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Problem

Energy is essential in almost every aspect of our lives and for the success of our economy. We face two long-term energy challenges:

1. tackling climate change by reducing carbon dioxide emissions both within the UK and abroad;
2. ensuring secure, clean and affordable energy as we become increasingly dependent on imported fuel.

The context in which we are seeking to meet these challenges is evolving, in particular:

- the growing evidence of the impact of climate change and wider international recognition that there needs to be a concerted global effort to cut greenhouse gas emissions, especially carbon dioxide;
- rising fossil fuel prices and slower than expected liberalisation of EU energy markets at a time when the UK is increasingly relying on imported energy;
- heightened awareness of the risks arising from the concentration of the world’s remaining oil and gas reserves in fewer regions around the world, namely the Middle East and North Africa, and Russia and Central Asia;
- in the UK, companies will need to make substantial new investment in power stations, the electricity grid, and gas infrastructure.

Climate change, as a result of rising greenhouse gas emissions, threatens the stability of the world’s climate, economy and population. More than two thirds of the world’s carbon dioxide emissions come from the way we produce and use energy, so energy policy has to play a major part in meeting this challenge.

At the same time energy demand worldwide continues to increase, particularly in the United States and emerging economies, such as China and India. On the basis of present policies, global energy demand will be more than 53% higher in 2030 than today\(^1\), with energy related greenhouse gas emissions around 55\% higher\(^2\).

Even if we realise more potential for increasing low carbon sources of energy, it is clear that coal, oil and gas will play a significant part in meeting the world’s energy needs for the foreseeable future. With the UK increasingly reliant on imported energy, there are risks arising from the concentration of fossil fuel reserves in fewer and further away places, some of them in less stable parts of the world.

Policy Objectives

The Government has four long-term goals for energy policy, which were first set out in the Energy White Paper 2003:

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\(^1\) P 66 World Energy Outlook, IEA, 2006
\(^2\) P 78 World Energy Outlook, IEA, 2006
1. to put the UK on a path to cut our carbon dioxide emissions by some 60% by about 2050, with real progress by 2020

2. to maintain reliable energy supplies

3. to promote competitive energy markets in the UK and beyond, helping to raise the rate of sustainable economic growth and thus improve our productivity

4. to ensure that every home is adequately and affordably heated

The Government launched an Energy Review in November 2005 to assess progress against these policy goals and to consider what further action was necessary to help make further progress. The Government published a report on the Energy Review in July 2006, setting out a series of proposals and consultations to help the UK make further progress towards its four policy goals. This further work, consultation and analysis culminated in an Energy White Paper, published in May 2007: “Meeting the Energy Challenge”.

Meeting the Energy Challenge set out the UK Government’s energy strategy for tackling climate change and ensuring clean, secure affordable energy as we become increasingly dependent on imported fuel. The strategy is based on the principle that independently regulated, competitive energy markets are the most cost-effective and efficient way of delivering our energy goals. The framework combines competition where it is desirable with regulation where it is necessary. The White Paper sets out how we will strengthen the existing policy and regulatory framework governing energy markets: it will be for companies to make investments in power stations, gas pipelines, gas storage and other energy infrastructure within the framework set down by Government.

The strategy set out in the Energy White Paper is being taken forward through a broad programme of activities and new measures, both legislative and non-legislative. Details of each of these elements can be found in chapter 11 of the White Paper3. This Impact Assessment concerns those measures that are being brought forward in the Energy Bill.

**Fit with the Climate Change and Planning Bills**

In addition to the Energy Bill, two other Bills - the Climate Change and Planning Bills – will include legislative measures that will help contribute to the implementation of the UK’s overall energy strategy:

- The Climate Change Bill will create a new legal framework for achieving, through domestic and international action, at least a 60% reduction in carbon dioxide emissions by 2050, and a 26-32% reduction by 2020, against a 1990 baseline. By putting the UK’s carbon reduction goals on a statutory basis, we can give business increased certainty for the long term about the Government’s commitment to carbon dioxide emissions reductions. The Climate Change Bill also includes, among other things, measures aimed at enabling climate change adaptation.

- The Planning Bill contains proposals to reform the planning regime for large scale infrastructure, including nationally significant energy projects. The Bill proposes the establishment of a new infrastructure planning commission which will examine and take decisions on applications for nationally significant infrastructure projects on the basis of clear national policy statements. The

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improvements to the planning regime should help to reduce cost, delay and uncertainty in decision-making and enable more timely private sector investment in energy infrastructure.

**Intended Effect**

The UK has a well established energy market regulatory framework within which companies make investments in energy infrastructure. The purpose of this Bill is to strengthen and modernise certain elements of this framework in order to support our overall energy strategy and help us make further progress against our long term challenges of:

- tackling climate change by reducing carbon emissions; and
- ensuring secure, clean and affordable energy, as we become increasingly dependent on imported energy.

Through the Energy Bill, we plan further to develop and/or introduce regulatory regimes to enable private sector investment in new electricity generation and other energy infrastructure. Many of the proposed measures are about creating the right conditions for investment through greater regulatory certainty and clarity and creating a wider range of available investment options for companies.

**Policy Proposals**

The Energy Bill is working towards multiple policy objectives and therefore brings forward a number of different measures. Most of the policy proposals have an individual Impact Assessment (IA) which discusses the options, rationale and costs and benefits in more detail. Where there is no impact assessment the measures have been summarised in this introduction. The individual IAs are set out in the sections following the introduction.

In many cases, individual proposals contribute to more than one policy objective. However, for the purposes of this Impact Assessment, we have brigaded individual measures under the primary policy objective that they target, while referring to any additional benefits in the text.

1. **Carbon Reduction**

The proposals with a primary objective of helping to make progress against the carbon reduction goal are:

- Carbon Capture and Storage (CCS), and;
- Strengthening and banding the Renewables Obligation.

A brief summary of the proposals is set out in Table 1.

These proposals will help further develop the regulatory and licensing framework for investment in low carbon, mainly large scale electricity generation. They will thereby help to expand the range of low carbon options available to companies making investments in the UK energy market. In setting the market framework in which these decisions are taken, the Government needs to ensure that, over time, we make the transition to a lower carbon mix.
The effective deployment of renewables is an important part of our strategy to tackle climate change and deploy cleaner sources of energy. However, companies need as broad a range of low carbon investment options as possible if we are to reduce carbon emissions whilst ensuring secure energy supplies in the most cost effective way. We are therefore also bringing forward proposals that will enable private sector investment in Carbon Capture and Storage (CCS) with electricity generation. CCS is an emerging combination of technologies which could reduce emissions from fossil fuel power stations by as much as 90%.

These policies will bring benefits to society in the form of carbon savings. Furthermore, by helping to increase the diversity of the UK’s electricity generation mix, new low carbon investments will also contribute to the UK’s security of supply. The amount of carbon saved from the measures in the Energy Bill will depend on amongst other things:

- the size of the CCS demonstration that comes forward as a result of the competition the Government launched in November 2007;
- market decisions on the use of CCS at a commercial level following the demonstration;
- the rate and scale of additional renewables investment and deployment as a result of our proposals to strengthen and modify the Renewables Obligation.
### TABLE 1

<table>
<thead>
<tr>
<th>Policy</th>
<th>Summary of Policy</th>
<th>Benefits/Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCS</td>
<td>The provisions will create a regulatory framework to enable a licensing regime for the storage offshore of carbon dioxide from electricity generation. The framework is required for the CCS demonstration competition which was launched in November 2007.</td>
<td>+ Enable investment in new electricity generation projects that will reduce the amount of carbon dioxide released into the atmosphere by up to 90% compared to conventional fossil fuel-fired power generation &lt;br&gt; + Demonstrate the technology to enable UK and international deployment &lt;br&gt; - no costs at present as the Bill only contains enabling powers</td>
</tr>
<tr>
<td>Banding of the Renewables Obligation</td>
<td>This policy strengthens and modifies the Renewables Obligation (RO) to include the power to create bands within the RO to bring on additional deployable technologies by providing appropriate levels of support. To maintain stability in the existing market, we are also proposing to allow certain types of generating stations to retain their entitlement of 1ROC/MWh if planning permission is received before banding is introduced.</td>
<td>+ increase the efficiency of the RO &lt;br&gt; + seeks to minimise over-subsidisation of more economic forms of renewable energy &lt;br&gt; + we predict this will encourage additional investment in renewables generation – particularly in emerging technologies &lt;br&gt; - predicted to cost consumers an additional £1.7 billion over the lifetime of the RO relative to current system &lt;br&gt; - increased administration costs of changing the RO</td>
</tr>
</tbody>
</table>

### Nuclear

The Government is also bringing forward proposals in this Bill to ensure energy companies make adequate provision to cover the full costs of decommissioning and their full share of the waste costs from any new nuclear power stations. If companies invest in new nuclear power stations, this will lead to carbon savings by displacing higher carbon emission power generation. Our analysis indicates that for every 1GW of new nuclear power generation that displaces gas fired power stations, around 700,000 tonnes of carbon would be saved.
2. Security of Supply

The main legislative proposal in the context of security of supply concerns Offshore Gas Infrastructure. The proposal will allow the UK to create a new licensing regime to enable private sector investment in new offshore gas storage facilities and offshore unloading of Liquefied Natural Gas (LNG) infrastructure. A brief summary of the proposals is set out in Table 2.

<table>
<thead>
<tr>
<th>Policy</th>
<th>Summary of Policy</th>
<th>Benefits/Costs</th>
</tr>
</thead>
</table>
| Offshore Gas Infrastructure | This policy simplifies the consents regime for investing into offshore natural gas storage and liquefied natural gas import facilities. | + improvements in the security of supply of gas by enabling new projects to come forward as well as speeding up of planned projects  
+ savings for developers from reduced delays for projects  
+ potential profits to business from the market opportunity of new offshore projects  
+ revenue for Crown Estate from resources not previously exploited  
- One-off Licensing regime costs for new projects |

As already mentioned, proposals to enable investment in Carbon Capture and Storage, Renewables and new nuclear power stations will also help the UK’s security of electricity supply by contributing to the diversity of the generation mix.

3. Competitive Energy Markets and Strengthening the Regulatory Framework

The Energy Bill also brings forward a number of proposals aimed at strengthening the regulatory framework for energy markets. The main proposals cover:

- Nuclear Waste and Decommissioning;
- Oil and Gas Decommissioning;
- Offshore Renewables Decommissioning;
- Other Oil and Gas licensing;
- Third Party Access to oil and gas infrastructure;
- Offshore Electricity Transmission Regime.

A brief summary of the proposals is set out in Table 3.
<table>
<thead>
<tr>
<th>Policy</th>
<th>Summary of Policy</th>
<th>Benefits/Costs</th>
</tr>
</thead>
</table>
| Nuclear Waste and Decommissioning | This policy aims to minimise the risk of the cost of an operator’s decommissioning and waste management costs of any new nuclear power station by ensuring that energy companies accumulate sufficient funds to meet their future liabilities. | + minimises the risk to the government of having to pay any part of the decommissioning and waste management costs of any new nuclear power stations.  
- costs to the operators are likely to include creating, maintaining and administering funds to cover decommissioning and waste management costs |
| Oil and Gas Decommissioning   | This policy aims to minimise the risk of the cost of decommissioning oil and gas installations falling to the tax payer, by ensuring that companies, in higher risk cases, will be required to put up security to meet their future liabilities. | + reduces the risk of the Government being liable for decommissioning costs in the event a relevant company becomes insolvent  
- additional administration costs to the operators  
- loss of potential access to segregated decommissioning funds for general creditors |
| Offshore Renewables Decommissioning | This policy aims to minimise the risk of the cost of decommissioning of offshore renewable energy installations falling to the tax payer, by ensuring that operators accumulate sufficient funds to meet their future liabilities. | + reduces the risk of the Government being liable for decommissioning costs in the event a relevant company becomes insolvent  
- additional administration costs to the operators  
- loss of potential access to segregated decommissioning funds for general creditors |
| Other Oil and Gas licensing    | This policy allows the Secretary of State to:  
Partially revoke a petroleum licence  
Ensure abandoned wells are not left ‘suspended’ indefinitely  
Deal with unconsented transfers of licence interests | + could save consortiums from having to reapply for a licence (and all the costs and time associated with it), for example, if one party becomes insolvent  
+ could save time of enforcers who may no longer need to revoke and then reissue the licence.  
+ provides increased legal clarity, which may encourage investment  
- in some cases, it may result in the bringing forward of the cost to companies of plugging a well, if required by the Secretary of State |
| Third Party Access            | This policy extends the scope of existing dispute resolution legislation to encompass all upstream oil and gas infrastructure. The legislation allows the Secretary of State to intervene (on request) where there is a dispute between a party finding it difficult to negotiate access to oil and gas pipelines, processing facilities or other upstream infrastructure owned by another company. | + users should get more timely, lower cost access to infrastructure resulting in faster/greater oil and gas production  
- some enforcement costs if disputes require resolution by the Secretary of State |
### Policy Summary of Policy Benefits/Costs

<table>
<thead>
<tr>
<th>Policy</th>
<th>Summary of Policy</th>
<th>Benefits/Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore Electricity Transmission Regime</td>
<td>This policy: Extends Ofgem’s powers to allow it to levy fees or charges on parties participating in the proposed transmission licence tender process in order to recover its costs Extends the existing legislation to provide for a statutory transfer scheme to provide a mechanism on application for compulsory transfer of property rights and liabilities between parties if commercial negotiations fails</td>
<td>+ will help to realise full benefits of competitive tendering + Ofgem will be able to fulfil its role effectively by recovering its costs in running the competitive tender exercises to appoint Offshore Transmission Owners + brings greater participant commitment and investor and participant confidence in the process. + brings environmental and societal benefits from avoiding delays in transferring property - the cost of providing financial commitments (refundable in certain circumstances) and bid costs of tender participants. - the loss or part loss of financial commitments by those parties not complying with the tender process, e.g. withdrawing. - costs associated with participating in the property transfer scheme appeals process.</td>
</tr>
</tbody>
</table>

### 4. Smart Meters

The Government is committed to improving the information customers receive on their energy bills to assist them in managing their use and reduce their carbon emissions. It believes that a key contribution to providing better metering and billing could be made by the introduction of smart meters.

Smart meters allow energy suppliers to communicate directly with their customers, removing the need for meter readings and ensuring entirely accurate bills with no estimates. They tell people about their energy use through either linked display units or other ways, such as through the internet or television. They could offer gas and electricity customers:

- more accurate - and fewer - estimated bills;
- information that could help them use less energy and encourage energy efficiency;
- lower costs through reduced peak consumption, because this would reduce the need for new network investment;
- increased security of supply, because the less energy we use, the less we need;
- more sustainable consumption through reduced carbon emissions.
The Bill contains an enabling power which puts in place the necessary legal powers to enable a roll out of smart meters via modified licence conditions. It is important to note therefore that the enabling power in the clauses only has effect when used. As such the impact assessments presented here do not assess the power itself, but a number of options for its potential use.

5. Updating legislation

The Bill brings forward a number of proposals to update and/or simplify the energy legislative framework. The policy proposals in this section of the Bill are:

- **5.1 Updating Reporting Requirements**
- **5.2 Transfer of Electricity Safety Functions to HSE**
- **5.3 Electricity and Gas meters - transfer of functions from Ofgem to NWML**
- **5.4 Nuclear Security Amendments**

These areas of the Bill have minimal impacts on business, and small impacts on the public sector. However, for completeness, we provide a brief explanation of the policy proposals below.

5.1 **Updating Reporting Requirements**

This area of the Bill deals with statutory obligations to report on a variety of energy related subjects. As the energy market has developed and diversified in recent years, various initiatives and legislative changes have resulted in a growing number of requirements on the Secretary of State to produce annual reports.

Many of these requirements remain valid; however, some have been superseded or do not align with ongoing developments in the context of energy and climate change policy. One example in the climate change context is the new requirement for a carbon budget reporting system which is being introduced through the Climate Change Bill. This part of the Bill on energy reports makes various amendments and repeals we are proposing to some of the energy related reporting obligations placed on the Secretary of State.

5.2 **Transfer of Electricity Safety Functions to HSE**

This area of the Bill relates to the enforcement of public safety requirements on electricity companies, following the transfer of electricity safety functions from BERR (then DTI) to HSE (Health and Safety Executive) in 2006. The purpose of the proposal is to complete the legislative implementation of one of Hampton's recommendations set out in his report “Reducing Administrative Burdens: Effective Inspection and Enforcement” (March 2005).

Hampton recommended that the electricity safety functions of BERR's Engineering Inspectorate be transferred to HSE. The electricity industry was consulted and supported the change. Accordingly, functions and resources were transferred from BERR to HSE in October 2006 with Ministerial approval by way of an agency agreement. The Inspectorate's other functions relating to electricity and gas planning proposals and enforcement of electricity quality and continuity requirements have been retained by BERR.
At present under the agency agreement the HSE inspectors have to operate using different enforcement procedures and lighter sanctions in the area of electricity safety of transmission and distribution than for similar enforcement work for other sectors carried out under the Health and Safety at Work Act.

The proposal will make changes to legislation in order to allow HSE to use the enforcement powers and sanctions available under the Health and Safety at Work Act when enforcing electricity safety standards.

There will be no impact on business acting lawfully. Businesses acting unlawfully will now be subject to a greater penalty. There are no administrative burdens from this proposal, and there is no change in the cost of enforcement - the function and resources have simply transferred from BERR to HSE.

5.3 Electricity and Gas Meters – transfer of functions from Ofgem to NWML

At present Ofgem has a statutory responsibility for inspecting electricity and gas meters, although in practice those functions relating to the standards and accuracy of meters are undertaken on its behalf by the National Weights and Measures Laboratory (NWML) following an administrative transfer in April 2006. The transfer was made to allow Ofgem to concentrate on its core role of economic regulation and to give companies a single point of contact on issues of legal metrology. New legislation is needed to complete the statutory transfer.

NWML’s role is to ensure UK measurement is accurate, fair and legal, and inspecting gas and electricity meters fits well with NWML’s existing functions. The objective of this proposal is to transfer statutory responsibility for the metrology regulation from Ofgem to the Secretary of State (i.e. NWML).

The proposal will not have any impacts on business since the administrative transfer has already been made. Business supports this proposed statutory transfer.

5.4 Nuclear Security Amendments

The proposals in this context are aimed at ensuring the nuclear security regulator (the Office of Civil Nuclear Security (OCNS)) is properly able to carry out its functions. Procedures around nuclear security and safety are a matter of national importance. The proposals will:

1. Introduce appropriate criminal sanctions on any person who steals (or attempts to steal) sensitive nuclear information from designated sites; and

2. Ensure OCNS’s continuing access to Civil Nuclear Police Authority sites following OCNS’s transfer to HSE.

• Ensuring appropriate sanctions for theft of sensitive nuclear information

The need for this change has arisen as a result of restructuring in the UK nuclear industry since the Energy Act 2004. Previously, sensitive nuclear information relating to uranium enrichment could only be kept on licensed nuclear sites which also held a permit to undertake the enrichment of uranium. Restructuring means that type of sensitive nuclear information may, in specific circumstances, now be taken and stored away from those licensed sites (for example at research facilities). The regulator (OCNS) is satisfied that the requirements on the holders of that information are sufficient to ensure the satisfactory
protection and safety of the information. The proposed change only seeks to ensure that persons stealing or attempting to steal sensitive nuclear material relating to uranium enrichment from these limited number of premises, can be prosecuted with stronger sanctions. The provisions apply to individuals stealing or attempting to steal sensitive information and have no impact on business.

- **OCNS Access to Civil Nuclear Police Authority sites**

  Responsibility for ensuring the security of nuclear sites rests with the OCNS. However, the specific power to oversee Civil Nuclear Police Authority (CNPA) premises sits with “officers of the Secretary of State’s department”.

  Following the transfer from DTI to HSE in April 2007, the OCNS are no longer considered to be officers of the Secretary of State’s department, and therefore do not have statutory authority to oversee CNPA premises. This amendment therefore looks to ensure that, as before, the OCNS – as the nuclear security regulator – has full access to all parts of a nuclear site, including CNPA premises.

  The provisions only allow authorised persons to access CNPA premises and have no impact on business.
1. Carbon Reduction

Climate change, as a result of rising greenhouse gas emissions, threatens the stability of the world’s climate, economy and population. More than two thirds of the world’s carbon dioxide emissions come from the way we produce and use energy, so energy policy will need to play a major part in meeting this challenge. Emitting carbon dioxide is an externality – a side effect that is not taken into account by the market, and therefore government intervention is necessary.

One of the energy policy goals is ‘to put the UK on a path to cut our carbon dioxide emissions by some 60% by about 2050, with real progress by 2020.’ The intended effect of the policy proposals in this section of the Bill is to work towards this goal by creating a wider range of low carbon electricity generation investment options.

The Impact Assessments for proposals on Carbon Capture and Storage (CCS), and strengthening and banding the Renewables Obligation follow.
What is the problem under consideration? Why is government intervention necessary?
Current legislative powers do not cover, and are not adequate to regulate the long-term storage of carbon dioxide below the seabed.
Government intervention is necessary in order to claim rights to store carbon dioxide beneath the continental shelf, to extend existing offshore legislation to CCS, and to regulate the storage process.

What are the policy objectives and the intended effects?
The development of a proportionate regulatory regime for Carbon Capture and Storage (CCS) so that a demonstration project can proceed.
The intended effect will be to allow carbon dioxide that would otherwise be released to the atmosphere and contribute to climate change to be permanently stored below the surface of the UK seabed in a way that protects the local environment and other users of the sea and seabed.
We aim to do this without giving rise to disproportionate regulatory costs.

What policy options have been considered? Please justify any preferred option.
Legislation is the only policy option. This is required to confer legal rights on the Crown to licence the offshore sub-surface space, to apply general offshore law and rights and obligations on operators of offshore CCS facilities, and to set up a regulatory regime, the details of which will be contained in licences and secondary legislation. Without legislation the storage of carbon dioxide would not be possible beyond territorial waters.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
This policy should be reviewed once EU legislation covering carbon dioxide storage is adopted (this is likely to be after 2010). Furthermore, when the impact assessment on the secondary legislation is published, it will include further information on monitoring and evaluation.

Ministerial Sign-off
For final proposal/implementation stage Impact Assessments:
I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:
[Signature]
Date: 09.01.08
### Summary: Analysis & Evidence

**Policy Option:** Carbon Capture and Storage  
**Description:** Energy Bill provisions

#### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description and scale of key monetised costs by ‘main affected groups’</th>
<th>Left blank because the provisions in the Bill do not create any costs. The licensing arrangements will be subject to full impact assessment during their development.</th>
</tr>
</thead>
</table>

#### ANNUAL BENEFITS

| Description and scale of key monetised benefits by ‘main affected groups’ | Left blank because the provisions in the Bill do not themselves create any benefits. The licensing arrangements will be subject to full impact assessment during its development.  
Using the shadow price of carbon in 2007 of £25/tCO2 gives an annual benefit of £28m - £92m using the Energy White Paper data of 0.3 - 1.0 MtC abated in 2020 (based on 0.3GW - 1.9GW of demonstration plant displacing equivalent fossil fuel-fired generation without CCS) |
|---|---|

### Key Assumptions/Sensitivities/Risks

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
</tr>
</thead>
</table>

- **What is the geographic coverage of the policy/option?** UK
- **On what date will the policy be implemented?** Dec 2008
- **Which organisation(s) will enforce the policy?** SoS
- **What is the total annual cost of enforcement for these organisations?** £ Figure not currently available
- **Does enforcement comply with Hampton principles?** Yes
- **Will implementation go beyond minimum EU requirements?** N/A
- **What is the value of the proposed offsetting measure per year?** £ 0
- **What is the value of changes in greenhouse gas emissions?** £ see benefits
- **Will the proposal have a significant impact on competition?** No
- **Annual cost (£-£) per organisation (excluding one-off)** | Micro | Small | Medium | Large |
- **Are any of these organisations exempt?** No | No | N/A | N/A

### Impact on Admin Burdens Baseline (2005 Prices) (Increase - Decrease)

<table>
<thead>
<tr>
<th>Increase of £</th>
<th>Decrease of £</th>
<th>Net Impact £</th>
</tr>
</thead>
</table>

**Key:**  
- Annual costs and benefits: Constant Prices  
- (Net) Present Value

20
A. The Issue

1. A power station with carbon capture and storage (CCS) will generate electricity from fossil fuels and capture the carbon dioxide that would otherwise be released to the atmosphere, and permanently store it deep underground. The aim of combining power generation with CCS is to reduce emissions of carbon dioxide to the atmosphere, where it would otherwise contribute to climate change.

2. A number of geological structures are thought to be suitable for the long-term storage of carbon dioxide. The most important of these from a UK perspective are the oil and gas fields in the North Sea. Many of these are coming to the end of their productive lives and it is possible that much of the infrastructure (e.g., pipelines, offshore facilities) could be suitable for use for carbon dioxide storage without major modification. Whilst described as carbon storage, the intention is actually permanent deposition of carbon dioxide in a contained, benign environment. There is no intention to recover the carbon dioxide once it has been placed into store, and indeed the regulatory regime (and in particular inclusion of CCS within the EU-ETS) will financially penalise the loss of carbon dioxide from a store. Work is in hand in Europe to amend the EU Emissions Trading Scheme (EU-ETS) to incorporate CCS, so that captured carbon is recognised by the scheme.

3. CCS associated with power generation is not a proven process at commercial scale. A number of initiatives are underway to facilitate the development of CCS. On 19 November 2007 a competition to support a CCS demonstration project in the UK was launched. This will be one of the first demonstrations anywhere in the world. When operational early in the next decade, this will make the UK a world leader in this globally important new technology. This project cannot go ahead without satisfactory regulatory arrangements.

4. Most of the activities involved in CCS are standard industrial processes and can be readily regulated without the need for new primary legislation. However, the storage of carbon dioxide underground is not well suited to carbon dioxide storage.

5. The Government set up a Task Force in 2006 to examine the regulatory framework that will facilitate CCS. The Task Force identified the need for new regulation, including:
   - The licensing of carbon dioxide storage sites and activities; and
   - The decommissioning and long-term liabilities associated with storage facilities.

B. Objectives

6. This impact assessment covers the intention to create an enabling framework in primary legislation that will allow the government to regulate the offshore storage with a view to its permanent disposal of carbon dioxide. There are four basic parts to what is proposed:

   i. Rights will be claimed to enable carbon dioxide to be stored beneath the seabed from 12 nmi to 200 nmi. No such right currently exists. This provision will therefore allow this activity to proceed on a secure legal basis. It imposes no regulatory burden. These rights will be vested in the Crown, and administered by The Crown Estate, which will in turn lease areas for carbon dioxide storage to potential developers.
ii. Existing offshore legislation will be extended to facilities undertaking carbon dioxide injection. Generally these do not impose new regulatory burdens, but there will be an obligation placed on operators to decommission structures that are no longer in use. These obligations will be similar or identical to those imposed on all other offshore structures, and derive from the UK’s obligations under international maritime conventions (OSPAR and the London Convention). There is considerable uncertainty about the cost of decommissioning a structure used for the injection of carbon dioxide. This is because no such structures currently exist and there are a number of engineering options available. However, the cost of decommissioning an ‘oil rig’ type structure could be something of the order of £5m to £300m, and the associated pipeline an additional £4m to £15m. Whilst the Bill provides the means to require the decommissioning of offshore structures used for carbon dioxide, the obligation to do so stems from commitments on the UK as a member of the OSPAR and London Conventions.

iii. There will be a prohibition on the offshore storage of carbon dioxide without a licence from the appropriate regulatory authority. Licence conditions will be imposed, which will in particular take account of our duty to protect the marine environment. The details of the regulatory framework for carbon dioxide storage will be set out in licences and subject to an Impact Assessment at the time we consult on the scope of the licence.

iv. There will be a power for government to incur expenditure in the Bill. These provisions are contingent in the event expenditure becomes necessary after the store has been delicensed.

7. The benefits of CCS as described below will not be realised without the change in legislation discussed in this Impact Assessment.

8. There is a strong case for the UK demonstration of CCS on power generation. The UK is well served with potential carbon dioxide storage sites, particularly under the seabed in the North Sea. Providing financial support and hosting UK-based CCS demonstration will help the Government meet its aims for climate change and wider energy policy goals by:

- reducing risks and demonstrating the costs of CCS, and taking the first step towards longer term cost reductions and the deployment of CCS on a wide scale nationally and more importantly, internationally;

- reinforcing the UK’s international leadership on climate change by investing in CCS technology that in time has the potential to make substantial reductions in global carbon dioxide emissions;

- helping to gain global agreement for a more ambitious drive to reduce emissions by demonstrating that CCS can safely deliver large reductions in emissions, and the extent to which it is affordable and reliable;

- giving the UK a lead in the design, construction and operation of CCS technologies. This will have the advantage of helping to build the skills base and demonstrate supply chains in the UK building on the existing experience and expertise in the UK of operating in the UK Continental Shelf. This should help put the UK in a stronger position to take advantage of future CCS investment opportunities; and

- enabling the UK to develop a comprehensive regulatory framework for CCS.
9. The legislation will create an enabling power, to allow actions to take place that previously could not. Therefore, at this stage there are no costs to business. A full IA with costs and administrative burdens estimated for those businesses wanting to take CCS forward will be estimated when developing the detailed licence requirements.

10. When this power is used to allow carbon dioxide to be stored, it will deliver savings in greenhouse gases. The capture and storage facility removes carbon dioxide that would otherwise be emitted to the atmosphere. The carbon dioxide produced is not ‘pure’, but may contain trace impurities that would otherwise be released to the atmosphere as well as by-products from the separation process. The total amount of carbon that is saved from this type of power generation will depend on the success of the demonstration project and whether the technology is taken forward by potential developers. As an illustration of the proportion of savings that could be made, 0.3 - 1.9 GW of demonstration that displaced the equivalent size of gas fired generation without CCS, would result in 0.3 - 1.0 million tonnes of carbon savings (as presented in the Energy White Paper). Using the shadow price of carbon in 2007 of £25/tCO₂ gives a benefit of £28m - £92m.

C. Specific Impact Tests

Competition Assessment

11. This enabling power will not have an impact on competition, as the legislation will impact equally on all organisations.

Small Firms Impact Test

12. This enabling power will not impact differently on small businesses.
## Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Carbon Assessment</td>
<td>No</td>
<td>No</td>
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<tr>
<td>Other Environment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Health Impact Assessment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Race Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Disability Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Gender Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Human Rights</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
Annexes

Annex A Equality Impact Tests

Race Equality
This enabling power will not impact on race equality, as the legislation will not affect individuals, and it will impact equally on all organisations.

Disability Equality
This enabling power will not impact on race equality, as the legislation will not affect individuals, and it will impact equally on all organisations.

Gender Equality
This enabling power will not impact on race equality, as the legislation will not affect individuals, and it will impact equally on all organisations.
Summary: Intervention & Options

<table>
<thead>
<tr>
<th>Department /Agency:</th>
<th>Title:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Department of Business, Enterprise and Regulatory Reform</td>
<td>Impact Assessment of Increasing renewables deployment in the UK and Banding of the Renewables Obligation (RO)</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Stage:</th>
<th>Version:</th>
<th>Date:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Final</td>
<td>Final</td>
<td>9th January 2008</td>
</tr>
</tbody>
</table>

Related Publications: (1) Banding of the Renewables Consultation, (2) Reform of the Renewables Consultation (May 2007) (3) Oxera Report

Available to view or download at:

Contact for enquiries: Stephen Clark  Telephone: 020 7215 5014

What is the problem under consideration? Why is government intervention necessary?
This policy addresses two problems. The first is how to increase renewables deployment in the UK, and the second is how to increase the efficiency of the Renewables Obligation (RO). Government intervention is necessary to support certain emerging renewable technologies further from commercialisation, to help establish a broad range of potential renewable technologies in the UK.

What are the policy objectives and the intended effects? The intended effects are to:
- Bring on emerging technologies through providing appropriate levels of support.
- Protect the position of most existing renewable energy projects and investors and also those projects under construction or active development.
- Allow adjustments to the Renewables Obligation to seek to minimise over-subsidisation of more economic forms of renewable energy, to increase value for money for consumers within the proposed 20% renewables obligation cap.

What policy options have been considered? Please justify any preferred option.
During policy development alternative options considered were: banding the RO to provide further support to new and emerging technologies; capping Renewables Obligation Certificates (ROC) prices and re-distributing excess funds to emerging technology projects; Government backed ROC contracts for emerging technologies and leaving the existing policy unchanged.
The Government's preferred option is to band the RO. Using a market mechanism means Government sets levels of support but leaves it up to the market to decide on the appropriate generation mix.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
The Government has proposed that the first two reviews of the RO banding levels should take place in time for any changes to the banding levels to be introduced on 1 April 2013 and 1 April 2018. This presumes there are no delays to timetable and introducing the secondary legislation.

Ministerial Sign-off For final proposal/implementation stage Impact Assessments:

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Date: 09.01.08
**Summary: Analysis & Evidence**

**Policy Option:** Renewables  

**Description:** The additional resource costs to the economy of generating additional electricity from renewables relative to gas-fired CCGT for a given mix of renewables.

### Annual Costs

<table>
<thead>
<tr>
<th>One-off (Transition)</th>
<th>Yrs</th>
<th>£</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Average Annual Cost (excluding one-off)**

- £ 105-110m over 38 years

**Total Cost (PV)**: £ 3.9bn – 4.1bn

**Other key non-monetised costs by ‘main affected groups’**

### Annual Benefits

<table>
<thead>
<tr>
<th>One-off</th>
<th>Yrs</th>
<th>£</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Average Annual Benefit (excluding one-off)**

- £ 26m over 38 years

**Total Benefit (PV)**: £ 1bn

**Other key non-monetised benefits by ‘main affected groups’**

- There are many benefits to increasing our deployment of renewables including: diversifying the electricity mix, reducing dependency on fossil fuels, and a reduction in carbon emissions.

**Key Assumptions/Sensitivities/Risks**

- Estimates are based on independent modelling of the Renewable Obligation.
- Estimates are sensitive to the projected costs of the technologies, which is uncertain, and the lifetimes of the technology which is 38 years – so whilst the RO runs to 2027 the benefits extend beyond this.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>38 Years</td>
<td>£ -2.9bn to - 3.1bn</td>
<td>£ -3.0bn</td>
</tr>
</tbody>
</table>

- What is the geographic coverage of the policy/option? UK
- On what date will the policy be implemented? 1 April 2009
- Which organisation(s) will enforce the policy? Ofgem
- What is the total annual cost of enforcement for these organisations? £ 1.3m
- Does enforcement comply with Hampton principles? Yes
- Will implementation go beyond minimum EU requirements? No
- What is the value of the proposed offsetting measure per year? £ N/A
- What is the value of changes in greenhouse gas emissions? £ 1bn
- Will the proposal have a significant impact on competition? No
- Annual cost (£-£) per organisation (excluding one-off) Micro: No, Small: No, Medium: No, Large: No
- Are any of these organisations exempt? No

**Impact on Admin Burdens Baseline (2005 Prices)**

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>Net Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 0.00</td>
<td>£ 0.00</td>
<td>£ 0.00</td>
</tr>
</tbody>
</table>

**Key:** Cost and benefits: Constant Prices (Net) Present Value
### Analysis & Evidence

#### Policy Option: Banding The Renewables Obligation

**Description:** IMPROVEMENTS IN THE COST EFFECTIVENESS OF THE RO FROM OUR PROPOSALS

**ANNUAL COSTS**

<table>
<thead>
<tr>
<th>One-off (Transition)</th>
<th>Yrs</th>
<th>£ --</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Cost (excluding one-off)</td>
<td>£ ---</td>
<td></td>
</tr>
</tbody>
</table>

**Total Cost (PV) £ (as per resource cost for this level of deployment and this mix under any policy, page 26)**

**ANNUAL BENEFITS**

<table>
<thead>
<tr>
<th>One-off</th>
<th>Yrs</th>
<th>£ ---</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Benefit (excluding one-off)</td>
<td>£ ---</td>
<td></td>
</tr>
</tbody>
</table>

**Total Benefit (PV) £ (as per resource cost for this level of deployment and this mix under any policy, page 26)**

**Key non-monetised costs** by ‘main affected groups’

- Description and scale of **key monetised costs** by ‘main affected groups’ Under our central scenario, the changes to strengthen and modify the Renewables Obligation will lead to an increase in consumer subsidy of £1.7bn over the lifetime of RO relative to the existing regime – around £85m annual average. This will result in a £3.6bn increase in renewables investment. Estimated system balancing costs of £330-530m over the lifetime of the RO.

- **Total Cost (PV) £**

- **Total Benefit (PV) £**

**Key non-monetised benefits** by ‘main affected groups’

- There will also be economic benefits to UK associated with the reduced dependency on fossil fuels and from the innovation stimulated in the renewables sector (to be offset against the costs of higher intermittency costed above).

- **As deployment of renewable technologies increases, is expected that costs of technologies will reduce over time. The increased investment in newer technologies should produce spillover effects in the rest of the economy in terms of improving the skill base, and international trade potential.**

**Key Assumptions/Sensitivities/Risks** as before

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
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<tbody>
<tr>
<td>2007</td>
<td>38 Years</td>
<td>£</td>
<td>£ (as per resource cost for this level of deployment and this mix under any policy, page 26)</td>
</tr>
</tbody>
</table>

- **What is the geographic coverage of the policy/option?** UK
- **On what date will the policy be implemented?** 1 April 2009
- **Which organisation(s) will enforce the policy?** Ofgem
- **What is the total annual cost of enforcement for these organisations?** £ N/A
- **Does enforcement comply with Hampton principles?** Yes
- **Will implementation go beyond minimum EU requirements?** N/A
- **What is the value of the proposed offsetting measure per year?** £ N/A
- **What is the value of changes in greenhouse gas emissions?** £ 1bn
- **Will the proposal have a significant impact on competition?** No
- **Annual cost (£-£) per organisation (excluding one-off)** Micro: No, Small: No, Medium: No, Large: No
- **Are any of these organisations exempt?** No

**Impact on Admin Burdens Baseline (2005 Prices) (Increase - Decrease)**

| Increase of | £ 0.00 | Decrease of | £ 0.00 | Net Impact | £ 0.00 |

**Key:** Annual costs and benefits: Constant Prices (Net) Present Value
A. Strategic Overview

1. Alongside the Energy White Paper, Meeting the Energy Challenge, published on 23 May 2007 a consultation document was published which sets out our plans to reform the Renewables Obligation (RO) (which closed 6 September) following an earlier Government consultation, “Reform of the Renewables Obligation and Statutory Consultation on the Renewables Obligation Order 2007”.

2. The recent renewables consultation set out, and sought views on, the detailed implementation of the changes which will need to be implemented through secondary legislation. Responses to this consultation have been analysed and conclusions will be published in a Government response outlining the further development of the policy.

Consultation

3. The proposals outlined in this impact assessment will be subject to the normal processes and parliamentary scrutiny for bringing forward primary legislation. There will then be a statutory consultation on the secondary legislation needed to implement the proposals. A further more detailed IA on the proposed changes will be developed for this statutory consultation.

B. The Issue

4. The existing RO, introduced in 2002, is the Government’s main policy mechanism to encourage the deployment of electricity generation capacity using renewable energy sources in the UK. It is underpinned by a substantial package of financial and non-financial supporting mechanisms and active assistance to the industry to develop its competitive potential. The RO has already provided, and will continue to provide, an impetus for the new renewable generating capacity that will be needed to meet the UK’s current 10% by 2010 target for electricity produced from renewable energy sources and as a basis for further reductions in carbon dioxide emissions.

5. The RO requires licensed electricity suppliers to ensure specified amounts of the electricity they supply are from renewable sources. For 2007/08, this level is 7.9% and rises to 15.4% in 2015/16. Without the financial support provided by the RO, most forms of renewable electricity would not be economic.

6. The RO does not operate in a vacuum. Movement in a number of external factors affect the effectiveness of the RO in supporting renewables technologies. An example of this is the cost of wind generation which has risen by some 25% over the past two years due in large part to the increased prices of wind turbines driven by international increases in demand, as well as underlying rises in costs of raw materials.

Regulatory Burdens and Compensatory Simplification

7. The details of the RO are set out in secondary legislation, introduced in 2002, with subsequent amendments in 2004, 2005, 2006 and 2007. The major regulatory burden imposed by the RO is that, in order to provide additional support for the generation of electricity from renewable sources, costs to all electricity consumers are increased. These costs are capped by the levels of the RO and the “buy-out” price in the RO. Previous
Impact Assessments considered the costs and benefits of the introduction and subsequent extension of the RO at the time that those measures were introduced.

8. The RO also imposes some regulatory burdens on renewable generators and the electricity supply industry in relation to the administration required to benefit from and comply with the scheme. The measures to introduce banding of the RO aim to improve the performance of the RO and make it easier for the renewables sector as a whole to benefit from the RO.

**Business sectors affected by the RO**

**General**

9. The main business sectors affected by the RO are:

- companies involved in the supply of electricity to all electricity consumers;
- companies involved in the generation of renewable electricity;
- large consumers of electricity who may be particularly affected, given that the RO increases the cost of electricity; and
- other users of biomass feedstock. Biomass users within the electricity generation industry are being banded up, this would increase the level of subsidy they ostensibly receive allowing them to potentially pay more for biomass compared with those industries not getting an additional subsidy under the RO (e.g. oleochemical users of tallow, wood panel industry for waste and new wood, paper industry for wood, animal feed, etc). These users of biomass materials for purposes other than electricity generation may be affected through the increased competition for these materials.

10. The Government’s proposals to band the Renewables Obligation are designed to bring forward more renewables generation by increasing the effectiveness of the RO. The proposals increase support to some forms of renewable generation, while reducing subsidy to others. It increases support and incentivises additional generation where there will be a cost to firms related to the technology costs over and above the costs of conventional technology. These costs include the cost of the technology, net of electricity revenues. Associated revenues such as payments from the buy-out fund recycling, being regarded as being internalised among firms.

11. The precise outcome of the proposed changes will depend on the impact of the changes on renewables generation, which in turn rely on a number of external market forces. Among those factors external to the RO are future electricity prices, future carbon prices, and future capital and operating costs for renewables. Sensitivity analysis\(^4\) carried out indicates that, under the current RO structure, a 10% reduction in future generation costs could increase the level of ROC eligible renewable electricity generation by 15–20% in 2015. Improvements in grid and planning will provide an additional boost.

**Small Business**

12. The major impact of the RO on the large majority of small businesses is likely to come from increased costs of electricity which, while affecting all electricity consumers will represent a larger proportion of income for smaller companies.

\(^4\) Results are based on modelling by Oxera independent consultants, based on their economic model of the renewable electricity market.
13. The majority of small businesses involved in renewables generation are likely to be operating technologies which are further from deployment, as such they will benefit from banding up of their technologies. Those small businesses involved in supply who are unlicensed will benefit from changes to legislation proposed to ensure they can claim ROCs without having to enter into sale and buyback arrangements. Small businesses involved in licensed electricity supply should not experience any additional burdens from the introduction of banding. BERR has held meetings with many relevant interested parties, companies and trade associations in the renewable energy sector and the proposals to band the RO have received support from a number of smaller companies actively developing projects or supplying technologies in these areas.

14. Measures introduced as part of the Renewables Obligation Order 2006 (Amendment Order) 2007\(^5\) are aimed at making it easier for smaller generators of renewable electricity – in many cases small businesses – to participate in the RO. These changes have been generally welcomed. We are currently working with Ofgem to identify what other administrative simplifications can be brought forward in the proposed 2009 Order (the Order that will implement banding following the proposed RO legislation in the Energy Bill).

**Objectives**

15. The objectives of the enabling proposals in the Energy Bill are to:

- Amend the RO so more expensive renewable energy generation technologies, especially those at an earlier point in their development are awarded more than 1 Renewables Obligation Certificate (ROC)/MWh of electricity generation (multiple ROCs) while projects in more economic technologies are awarded less than 1 ROC/MWh (fractional ROCs);

- Increase the level of the Obligation above the level previously announced if actual generation requires it (known as ‘headroom’), to a maximum level equivalent to 20%\(^6\);

- Subject to the outcome of the cross-industry working group, introduce a mechanism to mitigate the risk of a collapse in the price of a ROC in the event of full compliance with the Obligation;

- The Government also wishes to increase investor confidence in the predictability of the value of RO. Existing projects and those operational prior to the introduction of banding, with the exception of co-firing (which requires comparatively low levels of capital investment), will be grandfathered at 1 ROC/MWh until 2027.

- Amend legislation on Permitted Ways which covers uses of electricity which can be awarded ROCs (other than the generation and subsequent supply of electricity by licensed electricity suppliers to customers) to include electricity supplied to customers by unlicensed suppliers through a private wire network;

- Introduce a power to allow funding of Ofgem Administrative Costs; and

- Allowing a threshold to be introduced for payments out of the Late Payments Fund.

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\(^6\) The aim of having a maximum level for headroom is to ensure that costs to consumers are constrained.
Way forward?

16. The RO was devised as a technology-neutral instrument designed to bring forward the most economic forms of renewable generation. The Government believes it has been broadly effective in achieving this goal; renewable generation has grown significantly and there is a large pipeline of projects under development. Total generation from RO eligible renewable sources was 4.4% of electricity sales in 2006, up from 1.8% in 2002.

17. However, due to, among other factors, increased costs for renewables generation the RO, in its current form, seems unlikely to achieve Government targets. Government work on how to bring forward additional renewables generation, without prejudicing the investment that has already been undertaken on the basis of an unreformed RO, has led to the proposal to band the RO.

18. In order to develop the work on a “banded” RO, the Government commissioned Ernst & Young to research the costs of different renewable generation technologies, and to provide levelised costs of technologies under the RO, taking into account their capital and operational costs. This data was then provided to Oxera and formed the basis of their modelling work of changes to the RO, including the introduction of banding, the ski-slope and headroom mechanisms, and changes to the planning regime. Reports from both of these consultants were published alongside the 2007 RO consultation document. The cost assumptions for certain technologies have been amended following a consultation process during 2007.

19. Oxera used their model of the renewable generation market, which simulates the future pattern of renewables investment, based on assumptions as to the future revenue stream and costs of various renewable generation technologies (based on the Ernst & Young report and subsequent changes). They analysed a number of scenarios of RO reform, examining the impact on the renewables generation market. The scenarios included: leaving the RO unchanged; giving each technology a separate band dependent on need; and various ways of grouping technologies in different bands with differing levels of support. Other elements such as the implementation of a headroom mechanism to mitigate the risk of ROC price crashes were also modelled.

20. This work allowed the Government to identify a short list of scenarios which begin to deliver on our policy goals of increasing renewables generation against the 10% target and aspiration of 20% by 2020, through incentivising new renewables technologies and increasing carbon emissions savings, whilst increasing value for money for the consumer and increasing the efficiency of the RO. Oxera ran a number of sensitivity tests on the electricity price, the carbon price and technology costs, as well as some assumptions about the impact of reduced capital costs due to reform of planning and grid connection.

Options Identified

21. Results were modelled by Oxera independent consultants, based on their model of the renewable electricity market. Model assumptions and methodology are presented in the Oxera Report, published alongside the 2007 Energy White Paper. The model has been updated since the publication of that report, taking into account updated estimates of electricity sales, and technology costs. Results presented here are on the basis of this updated model. The options selected highlight particular effects of banding at specific

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levels. All of the scenarios quoted use the central case and are discounted over the lifetime of the RO, in line with HMT Green Book methodology and discount rates.  

22. There are three options set out in this paper:

1. Do Nothing
2. Banding Package with Many Bands
3. Banding Package with Five Bands

**Analyse the Options**

**Option One – Do Nothing**

23. The assumptions made about the current Obligation scenario (the base case) are:

- each MWh generated earns one ROC (i.e. no banding);
- it is based on the current trajectory to an obligation of 15.4% by 2015/16;
- it includes RPI-indexation of the buy-out price for the lifetime of the RO (until 2027);
- that the energy crop co-firing remains uncapped from 1 April 2007, and existing caps on non-energy crop co-firing are maintained – implying a cap of 10% until 2010/11, 5% until 2015/16 and nothing thereafter

24. The modelling indicates that unchanged (the “do-nothing” scenario), the RO will deliver 7.9% electricity from ROC eligible renewables generation by 2010 against a target of 10% and 11.4% by 2015 and 12.0% by 2020. Under this option the level of generation does not come near to the maximum obligation level of 15.4%.

25. This level of generation\(^{10}\) is achieved at a total subsidy cost of £21.5 billion over the lifetime of the policy. This cost is assumed to equate to the cost to consumers, the figures in the table assume 100% cost pass-through (this represents an upper limit and the true cost is likely to be somewhat less than this). Over the lifetime of the technologies supported through the RO, this option saves 83.8 million tonnes of carbon (MtC).

26. The lifetime resource cost\(^{11}\) (i.e. the cost of the renewable technologies) is estimated at £13.1 billion. Assuming costs are passed through to electricity, we estimate that the RO under this option leads to increased electricity prices of around 4%. The difference between the subsidy cost and the resource cost is therefore estimated at £8.4 billion over the lifetime of the renewable technologies. This represents the maximum ‘deadweight’ cost of the RO – a measure of the efficiency of the instrument. As electricity demand is relatively inelastic to price, we have not assumed any reduction in demand as a result of increase in electricity prices.

27. The deadweight cost is due in part to the amount by which technologies receive subsidy under the RO which is greater than the level needed for them to be economic. For example co-firing and landfill gas technologies which have very low capital costs, are over-subsidised by the current model. Delivering higher levels of deployment in an

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\(^{9}\) The Green Book: Appraisal and Evaluation in Central Government - [http://www.hm-treasury.gov.uk/media/9/C/Green_Book_03.pdf](http://www.hm-treasury.gov.uk/media/9/C/Green_Book_03.pdf)

\(^{10}\) under central electricity price/central technology cost assumptions.

\(^{11}\) under central electricity price/central technology cost assumptions.
unbanded RO would lead to higher proportionate deadweight. It is in part this deadweight element that the RO reforms are aiming to address.

<table>
<thead>
<tr>
<th>Option One: Do Nothing</th>
<th>2015</th>
<th>Lifetime</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>Central</td>
</tr>
<tr>
<td>Resource Cost £bn</td>
<td>0.7</td>
<td>0.7</td>
</tr>
<tr>
<td>Carbon Saved MtC</td>
<td>3.1</td>
<td>3.5</td>
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<tr>
<td>NPV Cost-Benefit £bn</td>
<td>0.5</td>
<td>0.4</td>
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<tr>
<td>Cost-Effectiveness £/tC</td>
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<tr>
<td>RO Deadweight Cost £bn</td>
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</table>

Distributional Analysis

<table>
<thead>
<tr>
<th></th>
<th>Exchequer Cost £bn</th>
<th>Firms Cost £bn</th>
<th>Consumer Cost £bn</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.1</td>
<td>0.7</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>0.1</td>
<td>0.7</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>0.1</td>
<td>0.7</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>1.5</td>
<td>12.5</td>
<td>21.5</td>
</tr>
<tr>
<td></td>
<td>1.7</td>
<td>12.4</td>
<td>21.5</td>
</tr>
<tr>
<td></td>
<td>2.1</td>
<td>13.8</td>
<td>21.7</td>
</tr>
</tbody>
</table>

Notes:

1. All costs are at 2007 real prices, discounted. The low scenario is modelled assuming technology costs are 10% higher in the central case, with a lower level of renewable generation. High costs assume technology costs are 10% lower than in the central case, with a higher level of generation, and therefore costs.

Option Two – Banding Package with many Bands (Scenario One)

28. This scenario assumes a separate band for each technology, with bands set to make the central step of each individual technology supply curve economic. Co-firing is uncapped.

29. A headroom mechanism is included, which increases the level of the obligation when the headroom threshold is breached, ensuring that the actual number of ROCs is 6% higher than generated volumes from 2009/10 with a ski-slope mechanism included to prevent the ‘cliff-edge’ problem when ROC volumes exceed the obligation size.

30. The modelling\textsuperscript{12} indicates that this scenario would deliver 9.6% generation from ROC eligible renewables generation by 2010, 13.6% by 2015 and 13.8% by 2020. This option brings forward significant increases in the amount of generation from co-firing (due to the removal of the cap on co-firing), offshore wind, and to a lesser extent wave and tidal (due to the banding up of these technologies). The higher banding levels increase both the actual deployment for renewable electricity as well as leading to more ROCs being issued than the level of generation in MWh. If ROCs are converted on a one for one basis, the level of ROCs in 2027/28 is 65 TWh compared to a volume of generation of 45 TWh. Combined with the increase in absolute deployment, this has the impact of reducing the ROC price, and therefore expected revenues, which in turn is predicted to decrease investment in onshore wind, despite onshore wind continuing to receive one ROC.

31. This level of generation is achieved at a lifetime cost to consumers of £27 billion over the lifetime of projects supported by the RO technologies, saving 96 MtC emissions.

\textsuperscript{12} under central electricity price/central technology cost assumptions.
Overall therefore, this option increases the level of renewables generation but at considerable cost to the consumer. Over the lifetime of the RO, the cost to the consumer increases by £5.5 billion compared to option 1.

32. This option increases the overall resource cost incurred through the RO, and increases the cost/tonne of carbon, and the Net Present Value (NPV) cost, compared to option one. This is because the banding regime brings forward more expensive technologies (i.e. offshore wind and wave and tidal). The fact that the resource cost increases less than the consumer subsidy results in a reduction in the lifetime deadweight of £2.3 billion compared to option one – representing increased efficiency of the subsidy. The higher level of resource cost results in a higher estimated impact on electricity prices, of around 6%, compared to around 4% in option one. This option delivers higher intermittent generation than option one (wind and wave and tidal power) which means that this option will incur higher system balancing costs than under option one, at an estimated cost of between £50 to £100m over the lifetime of the technologies.

33. However, this scenario is complex, and is more precise than it is really possible to be when predicting future costs. This banding regime is likely to require banding levels to be reset on a more frequent basis than one with fewer bands, introducing increased uncertainty for investors, and leading to Government trying to predict the market and pick winners, something consultation responses have strongly advised against.

### Option Two: Scenario 1

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>Central</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Resource Cost £bn</strong></td>
<td>1.1</td>
<td>1.2</td>
<td>1.5</td>
</tr>
<tr>
<td><strong>Carbon Saved MtC</strong></td>
<td>3.4</td>
<td>4.3</td>
<td>5.5</td>
</tr>
<tr>
<td><strong>NPV Cost-Benefit £bn (cost+/benefit-)</strong></td>
<td>0.8</td>
<td>0.9</td>
<td>1.0</td>
</tr>
<tr>
<td><strong>Cost-Effectiveness £/tC</strong></td>
<td>250</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>RO Deadweight Cost £bn</strong></td>
<td>0.2</td>
<td>0.4</td>
<td>0.1</td>
</tr>
</tbody>
</table>

### Distributional Analysis

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>Central</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Exchequer Cost £bn</strong></td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Firms Cost £bn</strong></td>
<td>1.1</td>
<td>1.2</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>Consumer Cost £bn</strong></td>
<td>1.3</td>
<td>1.6</td>
<td>1.4</td>
</tr>
</tbody>
</table>

**Notes:**

1. All costs are at 2007 real prices, discounted. The low scenario is modelled assuming technology costs are 10% higher in the central case, with a lower level of renewable generation. High costs assume technology costs are 10% lower than in the central case, with a higher level of generation, and therefore costs.

### Option Three – Banding Package with Five Bands

34. This scenario is the same as option two, though it simplifies the number of bands to be introduced, with each technology being assigned to one of five banding levels:

- **Landfill Gas** will receive 0.25 ROCs/MWh
- **Sewage gas, and cofiring non energy crop (regular) biomass** will receive 0.5 ROCs/MWh from 2009. The level of ROC multiplier for cofiring is assumed to reduce over time.
- **Technologies in the Reference Band** will receive 1 ROC/MWh
- **Technologies in the Post-Demonstration Band** will receive 1.5 ROCs/MWh
Technologies in the Emerging Technologies Band will receive 2 ROCs/MWh.

35. One of the most important features of this option is that it reduces the level of subsidy to the most expensive technologies compared to option two. This in turn reduces the divergence between the number of ROCs and the level of generation, which was found under option two. Under this option ROC prices remain at a level which allows an increase in the level of onshore wind generation over option two, while retaining the level of support necessary to bring forward increases in generation from biomass and offshore wind. The smaller number of bands also allows greater flexibility, and reduces the need for frequent reviews of the banding structure and levels.

36. The modelling indicates that\(^\text{13}\) this scenario would deliver 8.8% ROC eligible renewables generation by 2010, 13.4% by 2015 and 13.9% by 2020. Actual deployment will depend on the validity of the modelling assumptions. Additional policy measures proposed by Government including reforms to the planning and grid access regimes are intended to remove regulatory barriers to the deployment of renewable electricity generation. These policies are still in development and it has not been possible to assess the impact of these changes in the assumptions in this modelling work.

37. Under the assumptions for option three, the total subsidy is estimated at £23.2 billion (an increase in total subsidy of £1.7 billion compared to option one) over the lifetime of the RO. This option saves 96.5 MtC of Carbon over the lifetime of the technologies, an increase of 12.7 MtC over option one.

38. This option is predicted to bring forward higher levels of new renewables generation to option two and does so for a much lower increase in the cost to consumers of roughly £1.7 billion compared to option two - £5.5bn.

39. Resource costs under this option are estimated at £16.7 billion over the lifetime, an increase of £3.6 billion over option one. Cost/tonne of carbon as outlined in cost effectiveness in table below is £173, higher than option one, but lower than option two. The estimated lifetime deadweight cost of this option is £6.5 billion. This is a reduced deadweight cost of £1.9 billion compared to option one. The higher resource cost implies higher electricity prices than under option one (an estimated 5% increase in 2015) but lower than under option two. This option leads to a higher level of intermittent generation than under option one, which will incur some additional system balancing costs. Using UK Energy Research Centre (UKERC) estimates of the costs of intermittent generation, this leads to an additional cost of approximately £330 to 530 million over the lifetime of the RO.

\(^{13}\) under central electricity price/central technology cost assumptions.
40. This is the Government’s favoured Option.

<table>
<thead>
<tr>
<th>Option Three: Five Bands</th>
<th>2015¹</th>
<th>Lifetime</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>Central</td>
</tr>
<tr>
<td>Resource Cost £bn</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Carbon Saved MtC</td>
<td>3.6</td>
<td>4.2</td>
</tr>
<tr>
<td>NPV Cost-Benefit £bn (cost+/benefit-)</td>
<td>0.7</td>
<td>0.6</td>
</tr>
<tr>
<td>Cost-Effectiveness £/tC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RO Deadweight Cost £bn</td>
<td>0.3</td>
<td>0.4</td>
</tr>
<tr>
<td>Exchequer Cost £bn</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Firms Cost £bn</td>
<td>0.9</td>
<td>0.9</td>
</tr>
<tr>
<td>Consumer Cost £bn</td>
<td>1.2</td>
<td>1.3</td>
</tr>
</tbody>
</table>

Notes:
1. All costs are at 2007 real prices, discounted. Low scenario is modelled assuming technology costs are 10% higher in the central case, with a lower level of renewable generation. High costs assume technology costs are 10% lower than in the central case, with a higher level of generation, and therefore costs.

What are the costs?

41. Introducing a banded obligation on its own will not increase the total amount of cost subsidy in the RO, and therefore the costs to consumers. The out-turn costs to the consumers will vary with the actual level of deployment – increased deployment will be accompanied by increased costs to consumers. Under the central assumptions option three is predicted to cost consumers an additional £1.7 billion, compared to option one, over the lifetime of the RO.

42. The change will result in additional investment in renewables generation, in particular in higher cost technologies and will result in an increased resource cost of £3.6 billion. This resource cost is the cost to the economy of producing renewable energy as opposed to conventional generation. However, the ability to target support more effectively in a banded RO, means that banding has the potential to significantly increase the efficiency of the RO (reducing the ‘deadweight’ element of the subsidy) through providing support levels more closely linked to the needs of different technologies.

43. Increased activity under the Renewables Obligation (RO), and the introduction of banding, will lead to increased administrative costs for Ofgem. In addition Ofgem have argued that there should be a change to the way their overall costs for administering the RO are funded so that those who participate in the RO should also pay for it. We are therefore introducing a mechanism whereby Ofgem’s costs for the administration of the RO are defrayed by a call on the buyout fund. Ofgem have provided estimated costs based on BERR’s current proposals being implemented in legislation from 1 April 2009:
<table>
<thead>
<tr>
<th></th>
<th>09/10 (£000s)</th>
<th>10/11 (£000s)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Cost</strong></td>
<td>1,010</td>
<td>1,040</td>
</tr>
<tr>
<td><strong>Additional costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2007 reforms – set up costs</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2007 reforms – ongoing costs</td>
<td>145</td>
<td>145</td>
</tr>
<tr>
<td>Long term reforms – set up costs</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Long term reforms – ongoing costs</td>
<td>150</td>
<td>155</td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td>1,305</td>
<td>1,340</td>
</tr>
</tbody>
</table>

Work carried out by BERR and Ofgem suggests if all costs were met from the buyout fund the impact would be a reduction of approximately £0.05/MWh or 0.15%.

**Enforcement**

44. The Renewables Obligation Order (ROO) is administered and enforced by Ofgem. Non-compliance is considered a breach of a ‘relevant requirement’ of the Electricity Act and Ofgem may impose appropriate sanctions. Ofgem reports annually on its administration of the RO and conducts regular audits in relation to compliance with the RO.

**Monitoring & Evaluation**

45. BERR is responsible for monitoring the impact of the RO on the development of renewable energy and collects detailed information on growth in renewable energy generation and projects under development.

46. The changes proposed do not introduce any new powers of sanction. There is an expectation that changes to the way the RO is administered will ease the administrative burden on business by reducing the need for Ofgem to audit returns. However, detail of this is currently being worked through as part of the work on the secondary legislation that will flow from the proposals in the Energy Bill.

**Post-Implementation Review**

47. The Government has undertaken to carry out reviews of the Banded RO on an agreed timetable. The Government has proposed that the first two reviews of the RO banding levels should take place in time for any changes to the banding levels to be introduced on 1 April 2013 and 1 April 2018.

48. The Government will continue to monitor the performance of the RO and liaise closely with Ofgem on issues relating to the administration of the RO and compliance with it.

**Specific Impact Tests**

**Competition Assessment**

49. The RO is a market-based instrument that operates in a competitive market for electricity. The rules of the RO apply in a non-discriminatory way to all participants¹⁴ in

¹⁴ Some technologies are excluded from the benefits of the RO: coal methane; CCS
the renewables industry and electricity sector. The Government’s intention is that this will remain the case. Due to the way in which the RO recycles money from the buyout fund it should act as a positive incentive to competition between suppliers.

Small Firms Impact Test

50. Please find in paragraphs 12 – 14.

Sustainable Development

51. We are currently consulting on sustainability measures for biomass and energy crops as part of the consultation. The Government response will outline conclusions.

Carbon Assessment

52. The carbon assessment can be found in the tables analysing the options above.

Rural Proofing

53. A large proportion of renewable energy is produced in rural areas, particularly for certain forms of renewables such as onshore wind and biomass. The Obligation seeks to increase the proportion of energy from renewable sources, and a significant proportion of new energy developments will occur in rural areas. The Obligation affects businesses involved in the generation of renewable energy, including farmers who produce energy crops. It also affects rural communities living in the vicinity of new developments (e.g. windfarms and biomass generators).

54. The Obligation also raises energy prices and this affects rural consumers (as well as urban consumers). However, it is likely that the impacts of this will be greater in urban than in rural areas, as this is where most energy intensive industries are located.

55. There has been no separate or explicit assessment of the needs of rural areas.

56. Certain forms of renewable development impact disproportionately on rural areas, and there is often resistance to new developments from rural communities. Any resistance to new renewables projects needs to be viewed in the light of Government’s commitment to source an increasing proportion of energy from renewable sources, in order to combat climate change. The planning system also has a role in ensuring that new developments are sited in suitable locations.

57. The reform of the RO is set within this wider policy context and aims to ensure that renewables are promoted efficiently, that emerging sources of renewable energy are encouraged, and that the impact on consumer prices is reasonable. The focus has been more on the economically efficient promotion of the renewables sector than on addressing environmental or social impacts. For example, the reforms have proposed banding different forms of renewable generation methods to provide added incentives to some and less support to others. This has been based on the need for efficient cost incentives to encourage expansion of capacity, rather than on any assessment of social or environmental impact.

58. Some particular issues affecting rural businesses have been identified. For example:

- Until recently the RO has discriminated against businesses that are off the grid, since it requires businesses to sell and buy back energy in order to gain Renewable Obligation Certificates. Most businesses off the grid are in rural areas. The
reforms have addressed this by removing the need for sale and buyback for eligibility for ROCs.

- The RO has also been burdensome and difficult to access for microgenerators, a large proportion of which are likely to be in rural areas (though this has not been quantified). Recent reforms have sought to reduce this burden and make the RO more accessible.

59. The policy has been subject to extensive consultation at different stages. This has included business interests within the renewables sector, and consumer interests. It has included relevant rural business groups (including NFU and CLA as well as wind sector) but has not sought to engage rural community groups in particular.

60. Policy is informed by advisory boards including a Renewables Advisory Board and a Biomass Implementation Advisory Group (BIAG). These are primarily industry groups and include rural business interests as appropriate (e.g. the NFU and CLA are represented on BIAG).
### Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Carbon Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Other Environment</td>
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<td>No</td>
</tr>
<tr>
<td>Health Impact Assessment</td>
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<tr>
<td>Race Equality</td>
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<tr>
<td>Disability Equality</td>
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</tr>
<tr>
<td>Gender Equality</td>
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<td>Annex A</td>
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<tr>
<td>Human Rights</td>
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<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>
Annexes

Annex A Equality Impact Tests

Race Equality

This policy area does not impact on race equality as it applies to businesses supplying electricity and not individuals.

Disability Equality

This policy area does not impact on disability equality as it applies to businesses supplying electricity and not individuals.

Gender Equality

This policy area does not impact on gender equality as it applies to businesses supplying electricity and not individuals.
2. Security of Supply

The supply of energy is essential to the working of the UK and this is reflected in our second energy policy goal: ‘to maintain reliable energy supplies.’

Within the UK’s energy market framework, it is companies who make the investments in energy infrastructure that the UK needs to help ensure reliable energy supplies. As the UK becomes increasingly dependent on gas imports to meet its needs, we need to ensure that our market framework is up to date and provides the regulatory clarity and certainty that companies need to invest in offshore gas import and storage infrastructure.

The policy proposal in this section of the Bill is aimed at enabling private sector investment in offshore gas infrastructure in particular improving the regulatory framework for offshore natural gas storage and offshore Liquified Natural Gas (LNG) unloading consents.

The Impact Assessment for this area follows.
## Summary: Intervention & Options

<table>
<thead>
<tr>
<th>Department /Agency: Department of Business, Enterprise and Regulatory Reform</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title: Impact Assessment of Improving regulatory framework for offshore natural gas storage and offshore LNG unloading consents</td>
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<tr>
<td>Stage: Final</td>
</tr>
</tbody>
</table>

### Related Publications:

### Available to view or download at:

### Contact for enquiries:
Joy Anderton / Ricki Kiff
Telephone: 5194 / 5032

| What is the problem under consideration? Why is government intervention necessary? | There is a complex set of consents for developers investing in offshore gas and liquefied natural gas infrastructure in UK waters. The consent system is currently a barrier to some potential investments in offshore natural gas storage and liquefied natural gas unloading facilities. |
| --- |

| What are the policy objectives and the intended effects? | The objective of the policy is to facilitate investment in offshore natural gas storage and liquefied natural gas unloading facilities. The intended effects are to simplify the consenting process for these developments with a clear fit for purpose consents route for investment decision making; reduction in administrative burdens on developers; and certainty over legal operation and construction of new facilities. This will encourage more timely investment and contribute to security of supply in the longer term. |
| --- |

| What policy options have been considered? Please justify any preferred option. | The government has considered three options for gas supply and unloading: (1) no change to regulatory framework with improvements to existing guidance only (2) extend the offshore area available for permitted use of the seabed and water column beyond UK territorial waters by asserting rights under the United Nations Convention on the Law of the Sea (UNCLOS) (3) extend offshore rights as in option 2 and introduce new regulatory framework for consents. Options 1 and 2 stop short of meeting the objectives of providing certainty and clarity for developers and investors. Nearly all respondents supported the proposal for a new fit-for-purpose regulatory framework to give both small and large developers the certainty needed to take forward projects and to attract investment to the UK. |
| --- |

### When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
This policy will be reviewed in 2011 to guarantee two full years of operation after the regulations come into force before they are reviewed.

### Ministerial Sign-off

For final proposal/implementation stage Impact Assessments:

> I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Signed: [Signature]
Date: 09.01.08
### Summary: Analysis & Evidence

**Policy Option:** Assert specific rights outside the UK's territorial waters and introduce a new regulatory framework

**Description:**

The policy option describes asserting specific rights outside the UK's territorial waters and introducing a new regulatory framework.

<table>
<thead>
<tr>
<th><strong>ANNUAL COSTS</strong></th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>One-off (Transition)</strong></td>
<td><strong>Yrs</strong></td>
<td><strong>£ 340,000</strong></td>
</tr>
<tr>
<td><strong>Average Annual Cost (excluding one-off)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>£ Nil</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total Cost** (PV) **£ 1.4m**

**Other key non-monetised costs** by 'main affected groups': The cost of familiarisation is expected to be offset by the avoided cost of understanding the current complex, unfit-for-purpose regime. The costs of conditions in the licence are no different from current Petroleum licences. Cost of lease of relevant offshore sites from The Crown Estates to be negotiated.

<table>
<thead>
<tr>
<th><strong>ANNUAL BENEFITS</strong></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>One-off</strong></td>
<td><strong>Yrs</strong></td>
<td><strong>£ 50,000-100,000</strong></td>
</tr>
<tr>
<td><strong>Average Annual Benefit (excluding one-off)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>£ 40m</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total Benefit** (PV) **£400m**

**Other key non-monetised benefits** by 'main affected groups': Extra gas available might reduce the tightness of the gas market in some winters, hence reducing gas prices with benefits for consumers. Other benefits include lower financing costs.

**Key Assumptions/Sensitivities/Risks**

Apart from the speeding up of projects, the key base case assumption underpinning the estimate of the benefit of this proposal is that there will be one additional project every year for the first 5 years (to reflect potential pent up demand) with additional gas flowing from 2010/11. Each additional project increases gas supply by 1mcm on the days when the UK is short of gas. Risk of interruptions in supply falls, reducing potential losses to GDP. The assumption of each new project coming on stream providing only an extra 1mcm per day of additional gas supply is a cautious one; the assumption of the number of projects affected is perhaps less cautious. If the volume of additional gas doubled, the benefit could rise to a NPV of some £700m. Were the number of new projects to be only one every other year for the first five years (i.e. three projects in total) at the original expected volumes the benefit would fall to £250m.

<table>
<thead>
<tr>
<th><strong>Price Base</strong></th>
<th><strong>Time Period</strong></th>
<th><strong>Net Benefit Range (NPV)</strong></th>
<th><strong>NET BENEFIT (NPV Best estimate)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Year 2007</td>
<td>Years 14</td>
<td>£ 250m to 700m</td>
<td>£ 400m</td>
</tr>
</tbody>
</table>

---

- What is the geographic coverage of the policy/option? **UK**
- On what date will the policy be implemented? **Early 2009**
- Which organisation(s) will enforce the policy? **BERR**
- What is the total annual cost of enforcement for these organisations? **£ Minimal**
- Does enforcement comply with Hampton principles? **Yes**
- Will implementation go beyond minimum EU requirements? **No**
- What is the value of the proposed offsetting measure per year? **£ N/A**
- What is the value of changes in greenhouse gas emissions? **£ negligible**
- Will the proposal have a significant impact on competition? **No**
- Are any of these organisations exempt? **No**

<table>
<thead>
<tr>
<th><strong>Impact on Admin Burdens Baseline</strong> (2005 Prices)</th>
<th><strong>(Increase - Decrease)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Increase of</strong></td>
<td><strong>Decrease of</strong></td>
</tr>
<tr>
<td>£ 34k</td>
<td>£ 50-100k</td>
</tr>
</tbody>
</table>

**Key:**

- Annual costs and benefits: Constant Prices
- (Net) Present Value

---

48
Evidence Base (for summary sheets)

A. Strategic Overview

1. The strategic aim of the policy is to encourage the development of new offshore infrastructure to supply the UK with imported gas as natural gas supplies from the UK Continental Shelf decline. From 24 November 2006 to 16 February 2007 the DTI (BERR from June 2007) sought views on options to improve the regulatory framework for offshore gas infrastructure activities. The consultation aimed to help assess the need for regulatory reform, specifically dealing with natural gas storage in sub-seabed geological features, and the offshore unloading of Liquefied Natural Gas. An Impact Assessment, assessing the potential costs, benefits and risks of different policy options, was published with the consultation. This Impact Assessment builds on that IA and views received in response to the consultation.

B. The Issue

2. Gas production from the United Kingdom Continental Shelf (UKCS) is declining. Great Britain again became a net importer of gas on an annual basis in 2004; by 2020 we could be importing 60-80% of our gas requirements (with the low end of the range dependent on such factors as the take-up of energy efficiency measures. Where the existing regulatory framework delays or deters new investment, in gas infrastructure - for example, in import facilities and storage, there could be an increased risk of undersupply of gas to the UK market.

3. To meet this challenge, and to help the market deliver the gas that the UK needs, the Government must ensure that the regulatory framework facilitates the gas infrastructure developments that will help provide secure gas supplies to the UK.

Evidence of need for a better regulatory framework

General

4. There is considerable market interest in pursuing projects to enable natural gas to be stored offshore, and to enable Liquefied Natural Gas (LNG) to be imported to UK waters and unloaded into offshore facilities, as well as to onshore terminals in harbours. But the current regulatory and consenting framework for such offshore projects is unclear. In some cases the framework could only provide consent to certain parts of some proposed developments, and therefore cannot adequately deal with the range of activities that the market is considering. This view was supported by responses to the consultation, one of which noted that:

“The private sector is investing considerable sums of money in new gas infrastructure to meet the future needs of the UK. However, the current legislative regime does not facilitate the infrastructure investment that is now required in respect of LNG import and offshore gas storage facilities and may be acting as a disincentive to further investment.” Interconnector UK Ltd

“The current arrangements are not ideal for new developers as there is a lack of clarity around the most appropriate route to obtain the necessary consents and licensing.” E.On UK
5. Sixteen respondents (out of 26) saw the current regulatory framework as a disincentive to offshore development of gas storage facilities.

6. The consultation responses supported the Government’s view that there is a strong case for a revised framework, comprehensively dealing with all types of offshore gas storage and offshore unloading of LNG

The case for change

7. There is no one single piece of legislation that explicitly covers offshore gas supply activities. Consents have to be sought under a number of pieces of legislation, with no guarantee of this being a straightforward process. Developers who are starting to assess consenting possibilities are faced with a complex picture. Consents might need to be obtained through a number of pieces of existing legislation, from a number of Government departments (including BERR, DEFRA, and HSE) depending on the type of project and its distance from shore. Required consents may need to be sought under some or all of the following (this list may not be exhaustive):

- The Petroleum Act 1998 (BERR)
- The Food and Environment Protection Act 1985 (DEFRA)
- The Coast Protection Act 1949 (DEFRA)
- The Transport and Works Act 1992 (DfT)

8. The UK’s current legislative regime offshore was chiefly designed for licensing oil and gas production. It does not easily lend itself to the types of gas supply project that will need to come on stream to meet the UK’s needs as natural gas production from the UKCS declines. The market is considering investing in diverse projects, including opportunities for gas storage in offshore hydrocarbon and non-hydrocarbon features offshore (for example man-made salt caverns beneath the seabed), and in LNG offshore unloading projects. The latter would see LNG tankers either re-gasifying onboard and piping ashore, or delivering liquefied gas to a floating or fixed platform for the purpose of re-gasification. Additionally there could be interest in LNG imports being stored in offshore structures until it is required.

9. The complexity of the existing regulatory framework (and gaps in certain parts of it) mean that developers face considerable uncertainties and barriers to bringing forward these types of investment. Although spaces under the seabed can be the subject of leases by The Crown Estate within the 12nml limit of the territorial sea, there is a lack of clarity as to the rights that can be granted on behalf of the Crown beyond the 12nml limit. In addition, there are no specific provisions governing the offshore unloading of Liquefied Natural Gas (LNG). The provisions of the Town and Country Planning Act 1990 would only apply in cases where gas is unloaded at an onshore terminal.

10. The Food and Environment Protection Act (FEPA) 1985 regulates the deposit of substances in the sea and under the seabed, and that Act extends to the continental shelf. However, the licensing scheme under FEPA is not suited to the operational control of gas storage, although regulation of the actual injection of gas would be possible.

11. Responses to the recent consultation revealed that the impact of the current regime was resulting in, or would be likely to result in:

- Higher risks for investment in offshore infrastructure;
• Barriers to entry for prospective market participants;
• Unnecessary time and additional expense to develop new projects;
• Projects being delayed, terminated or not even initiated; and
• Increased finance costs.

C. Objective

12. The objective of the proposal in the Energy Bill is to facilitate the development of new types of gas supply and storage infrastructure from 2008 onwards. To achieve this, we plan to develop a clear regulatory framework that explicitly provides for the development of new types of gas supply and storage infrastructure offshore.

13. The 2007 Energy White Paper set out a commitment to bring forward new legislation that will provide a simple consents procedure involving two determining authorities, BERR and The Crown Estate. The intended effects are a clear route to investment decision making; reduction in the administrative burdens on developers through simplifying the consents process; and certainty over the legal operation and construction of new facilities. The aim is to enable timely investment and contribute to security of supply in the longer term.

The Energy Bill: Offshore Gas Infrastructure; Summary of main provisions

14. The proposed approach that will be taken forward through a combination of primary and secondary legislation includes:

• Asserting sovereign rights under Part V of the United Nations Convention on the Law of the Sea (UNCLOS) to the seabed and water column beyond the territorial sea for storage and unloading of gas, within areas defined as “Gas Importation and Storage Zones”;

• Taking powers to grant a Gas Unloading and Storage Licence (GUSL) on such terms and conditions as deemed fit and to enforce the provisions of the licence; and to sanction or remedy licence breaches;

• Making the new licence the principal regulatory requirement for organisations wishing to undertake offshore gas storage and unloading;

• Creating powers to regulate detailed aspects of the licensing regime through secondary legislation;

• Prohibiting these defined types of storage and unloading activities for anyone who does not hold a new Gas Unloading and Storage Licence (GUSL), and creating a corresponding criminal offences for non compliance.

15. There will be a clear process set out in regulations on how to apply for a Gas Unloading and Storage Licence (GUSL). The types of activities covered by this type of licence will include:

• the construction of a platform for the unloading of Liquefied Natural Gas (LNG) imported by ship:

      - for its immediate transmission to the UK mainland by sub sea pipe; or
- for short term storage in tanks on board the platform; and
- where the gas is re-gasified aboard ship or on the platform.

• the conversion and use of a sub sea geological structure or feature for the purposes of gas storage.

• the use of a depleted or partially depleted hydrocarbon field for the purposes of gas storage.

**Costing the impact of the new regulatory framework**

16. The Bill creates a power to establish grant a new Gas Unloading and Storage Licence (GUSL) for people wishing to undertake the activities above, including a power to prescribe model clauses to be included in such licences. The terms which would be relevant to a Gas Unloading and Storage Licence (GUSL) would be similar to those found in Petroleum Production licences. The costs associated with the licence have been based on the costs of a Petroleum Production licence and may be further refined when the regulations are made.

17. By way of illustration, a Petroleum Production licence requires:

- The requirement to appoint an operator.
- The requirement for BERR approval to drilling operations.
- The requirement for BERR consent to the erection or construction of relevant production infrastructure.
- The appointment of a fisheries liaison officer.
- The requirement to maintain records and samples, and to provide them to the BERR if requested.
- the collection of injection and production data related to hydrocarbons which is published by BERR.
- BERR approval to assigning the licence (this is where a new party is added to the licence or a different company takes over the licence)
- BERR consent to injection profiles.

18. As part of making an application for a Gas Unloading and Storage Licence (GUSL), a developer will need to submit a field development plan which sets out how the facility will be constructed and developed. The cost of the submission of a field development plan is not an additional cost to developers under the new licensing regime because it would be needed under the existing regulatory framework, for example when preparing to submit the planned development to Defra to obtain a consent under the Food and Environmental Protection Act 1985 (FEPA). In this case the cost is transferred to the BERR scheme. Where the new licensing policy results in projects coming forward which would not otherwise have done so, the field development plan has been factored in as a cost of the new scheme, but equally delivering additional benefits.

19. We believe that the improved regulatory scheme has the potential to attract new investment and enable projects to be developed that would not otherwise have come forward. For the purposes of this impact assessment we have estimated that there could
be one new and additional project per year on this basis for a period of five years, in response to the potential pent-up demand in the current system, with the first additional gas flowing as a result of these projects from 2010/2011. We have estimated that for any projects that come forward, the new regulatory framework will enable them to get off the ground more quickly. For the purposes of this impact assessment we have estimated that there could be three projects which fit into this category. The estimated costs are necessarily speculative, given that ultimately the number of projects which go forward will be determined by the market.

20. One benefit for projects which would have gone ahead under the existing regime will be greater certainty and clarity about the planning and consents process, which will save time, delay and money for each project. In the planning stage we estimate this could represent a saving in time and professional input of £50k - £100k per project.

21. The wider benefits of an improved regime that increases and speeds up investment in import and storage infrastructure might be the reduced risk of the undersupply of gas to the UK market and thus the reduced need for demand side response or involuntary interruptions in gas supply to end users. Oxera, in a study for BERR, has calculated the expected level of involuntary interruptions as being 0.01-0.02% of UK demand per year up to 2020/2021. This range of interruptions has a potential cost for the UK economy of £1.3bn (Net Present Value (NPV) 2007/08-2020/21). If this new regime results in additional projects coming on stream, this might reduce the likelihood and/or size of such interruptions and reduce the costs to the UK economy by some £400m over the period 2007/08-2020/21 (or an annual average cost of around £40m)\(^{15}\). Similarly speeding up investments, which would have gone ahead under the existing regime, might make more gas available during an otherwise tight winter and again this will have benefits of fewer interruptions and lower gas prices. The assumption (see footnote) of each new project coming on stream providing only an extra 1mcm per day of additional gas supply is a cautious one; the assumption of the number of projects affected is perhaps less cautious. If the volume of additional gas doubled, the benefit could rise to a NPV of some £700m. Were the number of new projects to be only one every other year for the first five years (i.e. three projects in total) at the original expected volumes the benefit would fall to £250m.

**Impact on Devolved Administrations**

22. The new licensing arrangements for offshore gas storage and unloading will apply to developers planning new infrastructure in the UK territorial sea and Continental Shelf up to 200nmi.

23. The new licensing scheme will assess whether projects meet environmental protection standards. In the territorial waters adjacent to England, and in the Continental Shelf area not adjacent to Scotland, the requirement to obtain a licence under the Food

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\(^{15}\) This calculation assumes that: as a result of the proposal more investment in import and storage facilities in the UK would take place; whilst the risk of any one facility breaking down is unchanged the impact of such a break down is less as each facility would be supplying a smaller proportion of the UK’s total gas demand and/or another facility can respond by increasing supply. This reduces the likelihood and/or potential size of an involuntary interruption of gas supply to end users. It also assumes that the proposal results in: 1 new project pa for five years; each project increases gas supply to the UK by 1mcm on the days when interruptions are imminent/expected; these increases in gas flows start in 2011/2012. This increased flow reduces the size of any possible gas supply interruption and therefore reduces the cost to the economy (ie some companies’ gas is not switched off and hence their production is not stopped). After 5 years it is assumed that, within this appraisal period, no further additional projects are attracted to the UK (eg tight market conditions might have changed). The estimate of the additional available gas is conservative and reflects possible non-availability on the day it is needed (eg due to plant break down, no LNG being unloaded or empty storage facilities). The analysis takes no account of the possible changes to the risk of break downs nor the impacts on other investment plans (eg displacement).
and Environment Protection Act 1985 (FEPA) will be disapplied and it will be possible for a developer to apply to BERR for one licence (which will include any necessary element of environmental protection). In the case of the territorial waters adjacent to Scotland, Wales and Northern Ireland, and the Continental Shelf adjacent to Scotland, a FEPA consent will continue to be required, subject to the policy of each devolved administration who could agree to disapply FEPA under secondary legislation.

**Consultation across Government**

24. Discussions concerning the proposed policy have taken place with DEFRA, MoD, FCO, HMRC, HSE and HMT. The Devolved Administrations have been consulted on the development of the policy options.

**Public Consultations**

**Marine Bill consultation**

25. Initial consultation on an offshore licensing regime was carried out through the DEFRA Marine Bill consultation process, which closed in July 2006. Approximately 1250 responses were received in total. Although fewer than 5% responded to questions regarding the proposed licensing regime, the need to take steps that ensure security of gas supply was universally recognised. The activities were generally welcomed, and the industry’s previous safe history noted. Some environmental concerns were raised. In particular there was concern about the effect on water quality as a result of solution mining and the discharge of brine to create salt caverns. These activities will be subject to the standard environmental assessment procedures.

26. Where views were expressed on a regulatory regime, about 60% of respondents stated that they wished to see new legislation cover the storage of gas in sub-seabed geological features. Opinions were fairly evenly divided as to whether this should be achieved by a separate, fit for purpose regime or a reformed petroleum licensing regime where there was sufficient flexibility to deal with this activity.

27. Where new legislation was to be introduced, this should not be contrary to the objective of rationalisation. Developers were also concerned as to how this would dovetail with the current production licensing regime, and wished to ensure that it was designed so as to optimise the production of remaining reserves, and promote the use of existing fields and facilities for storage purposes.

**BERR (formerly DTI) Consultation on offshore natural gas storage and liquefied natural gas import facilities**

28. BERR consulted on three options – as set out below.


30. The Crown Estate and Ofgem have been involved in the consideration of policy options. Comments provided in the response document pertaining to issues in which The Crown Estate, Ofgem or HMRC have an interest, have been raised with those organisations.
D. Options Identified in the consultation

31. The consultation document considered two specific issues: Offshore natural gas storage in non-hydrocarbon and hydrocarbon features, and offshore unloading of LNG. The options put forward in the consultation are summarised below. Since the consultation responses were received it has been decided for practical reasons to merge the Gas Storage and Unloading licenses into one licence.

**Offshore gas storage and unloading of Liquefied Natural Gas (LNG)**

1. Do nothing

2. Extend area for developments authorised by The Crown Estate to beyond 12 nautical miles (nml)

3. Introduce in addition a new regulatory framework

**Costs and benefits, risks, and impacts on competition and small firms.**

32. The costs, benefits and likely risks associated with each measure are set out below, alongside any unintended consequences/risks, enforcement and monitoring, and the impacts on competition and small firms.

E. Analyse the Options

**Offshore gas storage and unloading of Liquefied Natural Gas (LNG)**

**Option 1: do nothing**

33. Gas storage developments and offshore unloading facilities are regulated, where possible, through existing legislation (including the Petroleum Act 1998, the Food and Environment Protection Act 1985 and the Coast Protection Act 1949 (as may be amended by the Marine Bill), or additional legislation as appropriate).

34. Consents for these projects would in practice only be granted where the development is within the 12 nautical limit of the territorial sea, or which The Crown Estate will be able to issue a lease. Newer technologies, such as developments in non-hydrocarbon features may not be able to proceed due to the uncertainty over whether the existing legislative provisions apply to them. In the case of offshore unloading of LNG, no rights to establish fixed or floating platforms are granted by The Crown Estate beyond the 12 nautical limit of the territorial sea.

35. Under this option, the Government would make no changes to the legislation. The option would be to improve the guidance available to market participants on the existing legislation which is applicable, the consents which might be sought, from whom, and on the process for doing so.

**Benefits**

36. There are no benefits for security of energy supply. However there are the avoided costs of familiarisation with a new regime, and the time savings, both for market participants and for Parliament, in not pursuing legislative change. These benefits are minimal. Arguably the costs of familiarisation with a new licensing scheme would be less than the effort required to cope with the uncertainties of the existing system. Government clarification could be helpful but would not clear up the uncertainties.
37. There are arguably fewer environmental impacts from this option because it would deter projects from going forward and give rise to less offshore drilling.

Costs

38. If we made no changes to the current framework, developers of storage projects in hydrocarbon features may be able to proceed under their Petroleum licences. Storage in hydrocarbon fields can at present be regulated by means a suitable modification of a petroleum licence, since in that case naturally-occurring hydrocarbons will inevitably be produced when the injected gas is recovered. However, this is an artificial expedient, given that the production of native petroleum will be a merely incidental by-product of the recovery of stored gas. A requirement to apply for consent to store gas, given under a modified petroleum licence, has no clear advantages over a requirement to apply for a licence under a tailor-made gas storage regime, and has the disadvantages of lack of certainty and transparency.

Developers looking to make use of non-hydrocarbon features would continue to struggle through the current, imperfect system, creating undue burden on business, or alternatively they could make the decision to invest elsewhere. In either case, some uncertainty would attach to developments beyond 12nml.

39. In the case of LNG unloading offshore, projects beyond 12nml would not be able to go ahead resulting in negative implications for security of supply (see previous sections above). There is a possibility that this void might be filled by other onshore projects. However if maintaining the current regime proved to be a disincentive to market participants, this would probably be at the expense of the diversity of gas supplies for the UK.

40. As well as doing nothing to aid in security of supply, a lack of offshore stored gas due to lack of investment or a delayed start to a project might lead to a tighter demand supply balance and this could lead to higher gas prices for around 0.5m industrial gas users and 21m household customers. Where the market is tight and gas prices rise, firms will consider voluntarily reducing their gas demand. For example, in the winter of 2005/06 when the market was tight, on the 100 highest demand days there was an average of 27mcm of demand reduction (at a cost of some £400m to the economy in lost production).

41. Where the market is even tighter, involuntary gas supply interruptions may result. The probability of an interruption is small. Oxera, in a study for BERR, has calculated the expected level of involuntary interruptions as being 0.01-0.02% of UK demand per year up to 2020/2021. This has a cost to the UK’s GDP of around £1.3bn (discounted over the period 2007/08-2020/21). Whilst the likelihood that one of the particular project types discussed here might prevent such an interruption is uncertain, the potential for reducing such costs is significant.

42. Deterring investment, where the firm’s project appraisal indicates that an investment would otherwise be positive, leads to a lost profitable opportunity. Delaying commissioning can mean that developers miss a key profitable year – for example in a winter when the market is potentially tight, it is possible that there will be high gas prices and a need for significant volumes of stored gas to be placed on the market; whereas a year or so later this need might be less.

43. Uncertainty in terms of whether a project might be allowed to go ahead, its timing or concern that a project might be being developed under an inadequate legislative regime could lead to a higher cost of finance to reflect the risks of high costs and uncertainty over the stream of income.
44. A delay of a year might cost an extra £50,000 - £100,000 per project in terms of management time, keeping up to speed with developments on the consents issues with different departments and agencies and retaining appropriate professional advice on the uncertainties of the system. Costs are likely to rise depending on the maturity of the project, and the costs of a year’s delay to a mature project could be substantially higher. In addition, significant legal advice will be required under the ill-fitting existing regime initially and throughout the development process.

Risks:

45. Developers are constrained to using sub-seabed features within the 12nml territorial waters as opposed to the wider range of options that might be feasible if development were permitted beyond this limit. This reduces the potential area for development. Within the 12nml limit there are few fields, and of these, there is then a question as to which are genuinely suitable for gas storage purposes. The big risk then, is that the UK denies itself access to any further meaningful offshore gas storage opportunities. Developers face added cost and uncertainty to their projects due to the complex legislative route that may be needed to seek consents. This could be a barrier to entry or prevent a project being viewed as feasible. Overall there could be fewer storage options for the UK, which may contribute to gas market tightness.

46. The offshore unloading of LNG imports would be limited to the 12nml limit of the territorial sea. There would be no fit for purpose regime for licensing this activity, resulting in increased burdens on business as they may experience delays in trying to gain consents for activities that are not expressly provided. Furthermore, developers may, on application for such consents, incur considerable legal and management costs trying to understand the applicability of current regimes to their project. Ultimately, they may not be granted consent, if the current legislation is not deemed suitable to consent to such activities.

Option 2: Extend the area in which such activities are permitted, but without revision of consents process

47. The UK could assert rights under Part V the United Nations Convention on the Law of the Sea (UNCLOS) to make exclusive use of the seabed, porous space under the seabed, and the water column, in areas of the continental shelf beyond the limit of the UK’s territorial waters. These rights would be vested in the Crown and authorised by The Crown Estate. This would not need legislation by Parliament and would extend the area of the sea and seabed in which gas storage and LNG unloading activities could be authorised by The Crown Estate.

48. By making provision for such activities beyond 12nmls, a number of additional sites with potential for gas storage and LNG unloading would be available to developers. Developers wishing to bring forward projects could then apply to The Crown Estate for an authorisation to do so, even where the feature in question lies beyond the 12nml limit of the territorial sea. In the case of gas storage projects in partially depleted hydrocarbon fields, it would also be necessary to obtain a licence under the Petroleum Act 1998 (or rely on an existing licence) with the legal issue explained in option 1 being the same. Developers would also have to apply for consents under existing legislation regulating deposits under the seabed, such as FEPA.

Benefit

49. There could be some limited benefits to security of supply as there would be an increased area of seabed available to be licensed for the purpose of storing gas in its
porous space. Asserting rights to use the continental shelf for the purpose of unloading LNG imports, would extend the area for the siting of such installations and increase the potential to benefit from utilising existing infrastructure in UK waters. But no realisable additional benefits would accrue if developers are not able to gain consents for their projects under current legislation. There would be unlikely to be any benefits for developers wanting to develop gas storage in non-hydrocarbon features and those wanting to make use of platforms offshore for LNG unloading.

Costs

50. The costs for this option would be largely the same as for option 1. Creating a larger area in which developers can pursue storage and unloading developments could be beneficial, but only if it outweighs the disadvantages that developers face in applying for appropriate consents. If more developers were not encouraged to apply, then the outcome could do little for security of supply. Administrative burden costs to the developer would be the same for option 1.

Risks

51. Whilst some developers may be able to realise the benefits of the extended area of the seabed for gas storage, there is a risk that for others there is simply an increase in uncertainty and frustration about the relevance of the existing legislation to help bring projects forward and the complex legislative route that developers would have to follow to seek consents. This is likely to continue to be a barrier to entry and prevent a project being viewed as feasible. Overall there could be insufficient increase in the numbers of gas storage and import options for the UK, which may contribute to gas market tightness.

Option 3: Introduce new regulatory framework

52. This option would introduce a new fit for purpose licensing scheme to provide to regulate all offshore gas storage and offshore LNG unloading in the UK’s territorial waters and continental shelf.

53. As for option 2, the Government would assert the rights of the UK under UNCLOS to make exclusive use of the seabed, the porous space under the seabed, or the water column, for storage or for establishing LNG unloading facilities, in areas beyond the limit of the UK’s territorial waters. The rights would be vested in the Crown, and authorised by The Crown Estate.

54. There would be a new requirement for developers to obtain a Gas Unloading and Storage Licence (GUSL) from the Secretary of State (to be given by the Department of Business, Enterprise and Regulatory Reform). Developers would have to seek an authorisation to use a particular space below the seabed from The Crown Estate, and would also apply to the Secretary of State for Business, Enterprise and Regulatory Reform for authorisation to store gas in that space. By enacting new legislative provisions (for example inserting new provisions into the Petroleum Act 1998) we would set out a new regulatory framework for gas storage in both hydrocarbon and non-hydrocarbon features.

55. The licence would also cover activities related to the construction of an offshore fixed or floating platform, and its ongoing operation (unless it is part of a Petroleum Licensed development). This type of platform could connect by submarine pipeline directly with the UK mainland or with an existing sub-sea pipeline for the purpose of unloading imported LNG. In line with oil and gas developments, we would remove the requirement for a FEPA Licence (which would be an unnecessary requirement) in English waters.
Scotland, Wales and Northern Ireland would also have the option to remove this duplicate requirement. As in the case of gas storage, an authorisation would have to be obtained from The Crown Estate to use a specific area of the seabed or sea for that purpose.

56. For gas storage in hydrocarbon features, a Petroleum Licence under Part 1 of the Petroleum Act 1998 would continue to be required, and would be complemented by a Gas Unloading and Storage Licence (GUSL) obtained from the Secretary of State for Business, Enterprise and Regulatory Reform that specifically provided for storage activities. The new licensing arrangements would not duplicate the conditions of the existing Petroleum Licence.

57. For gas storage in non-hydrocarbon features, a Gas Unloading and Storage Licence (GUSL) would need to be obtained from the Secretary of State for Business, Enterprise and Regulatory Reform. Under this option, The Crown Estate would conduct a gas storage tender process, where required, for the offshore methane storage in non-hydrocarbon features in close consultation with the BERR (as is the case with offshore renewable energy), and issue a geographically-bound exploration lease to successful applicants.

58. It would be a condition of The Crown Estate lease that the developer applies to the BERR for a Gas Unloading and Storage Licence (GUSL) in order that test drilling for the site could be undertaken. The GSL will be valid for the period covering exploration and production purposes so if the site proves suitable for gas storage, the developer will retain the licence; if it is not suitable, the licence will be relinquished.

59. A licence for gas storage in either scenario would only be issued if the developer could meet certain environmental and technical thresholds required by the BERR. It would be issued with terms similar to those held in Petroleum Production Licences (though noting that these would not be replicated in the case of existing Petroleum Licences being held).

60. The BERR licence would be given with conditions such as data reporting for the national hydrocarbon accounts and would only be approved after the considerations of other sea users had been taken into account.

Benefits

61. This option offers a clear consenting regime with appropriate controls on the siting of storage developments and offshore unloading platforms, environmental aspects of activities, and any associated infrastructure, including intra-field pipelines. Pipelines to the mainland will be covered by Part 3 of the Petroleum Act 1998 (and the decommissioning of infrastructure by Part 4). The increase in clarity and certainty may facilitate and encourage new projects to come forward thereby increasing security of supply. The new regime would offer clarity for developers as to which body consents to what, and how the consents are obtained, which reduces project costs and, importantly, project risk and therefore reduces the cost of overall financing projects.

62. The benefits are the avoided costs of option 1 (see above) – ie less management time (£50-100k per project that is speeded up under the proposed regime) and better security of supply (and hence fewer forced interruptions in gas supply) as a result of the increase gas flow from additional projects going ahead.

63. As LNG transportation ships become larger, for reasons of economy of scale, there may be justification for them being able to unload their cargo (and possibly store on the
facility for short periods) at distances further from the shore. This would also reduce their turn-around time with added economic benefit. These unloading facilities might be consented to more speedily than in the case of facilities constructed on land (which would require approval under the Town and Country Planning Act by the adjacent Local Planning Authority). An additional benefit would be the ability to obtain the necessary authorisations to construct such facilities beyond the 12nml limit and this might improve security of supply.

64. To the extent that the requirement for a FEPA consent can be disapplied across the constituent parts of the UK, developers would benefit from the removal of this additional consenting process, whilst environmental considerations are met within the process of awarding the Gas Unloading and Storage Licence.

Costs

65. Administrative burdens are intended to be low, as this legislation would be a simplification measure compared to the current framework, where one exists – the administrative cost of obtaining a licence for a new project might be some £31k per project (based on Petroleum Act costs) plus £3,000 for the cost of the licence itself. For additional projects, the cost of a field development licence (£306k per project) would be required. Whilst there will be the costs of initial familiarisation with a new regime (primarily by legally-trained staff at a cost of some thousands of pounds per potential new entrant), this will need to be balanced against the fact that developers are currently struggling to understand how they might proceed in the framework that exists, and whether the legislative gaps could prevent a project from commissioning ultimately. Developers have called for fit for purpose legislation to reduce risk, uncertainty and delays. There would be a light-touch monitoring regime by government to confirm that key licence conditions are being met.

Risks

66. The Energy Bill will introduce the new regulatory framework to put in place these licensing arrangements. Further details of the licensing scheme will be set out in regulations. There will be consultation on the draft regulations. There is a risk that the time taken to bring the new licensing scheme into effect will act as a disincentive to developers in the short term. The licensing scheme will need to be sufficiently widely drafted so as to capture the range of innovative new technologies which are being developed in this sector. The period of public consultation on the regulations will help to ensure the licensing scheme is fully fit for purpose.

Conclusion

67. Doing nothing would fail to address the existing barriers to the development of offshore storage and LNG unloading projects. Option 2 may provide some additional flexibility to developers with an interest in gas storage under the sea-bed in hydrocarbon features, but only if they could gain consents without undue burden, and with legal certainty, under the current system. Option 3 would provide a tailor-made solution for all developers of gas storage and offshore LNG import facilities, including encouraging the best use of innovative technologies. It would both provide a regulatory framework that specifically provided for such activities, reduce burden on business by streamlining processes, maximise the area of the sea-bed available for these activities and maintain appropriate environmental controls.
**Business sectors affected**

68. Whilst we have had discussions with a number of companies wishing to develop a variety of offshore projects, it would be inappropriate to provide exact details due to commercial sensitivities. We have spoken to both multinational players, and much smaller developers, British based and foreign companies. At this stage we would estimate that the number of interested parties who have discussed their plans with us would run to double figures. We have no way of knowing how many other companies may be in the early stages of project development, as companies are not obliged to discuss their plans with BERR. We are likely to find that as more companies become aware of the work to improve the offshore consents regime, they will approach BERR to discuss their plans.

69. Key sectors directly affected by the current situation and any proposals taken forward are likely to be gas producers, storage companies and LNG importers. It is likely that these will not be small firms, though there might be some small innovative firms wishing to take forward such projects, perhaps on a smaller scale. Indirectly, if interruptions are less frequent and/or gas prices lower with the proposed changes going ahead, all 0.5m industrial and commercial gas users (and 21m households on the gas network) will be positively affected. Public services, such as schools, hospitals, government offices etc will similarly be positively affected if they are gas users.

**Issues of equity and fairness**

70. The proposed legislation does not correct, or introduce, a new inequality. The beneficiaries of the proposed legislation will be the same commercial entities that also bear the cost of application: incurring capital expenditure, and payment of a commercial rent for the use of the licensed site. Therefore no negative aspects of equality and fairness are perceived in the proposed options. It could be argued that the new framework introduces mechanisms by which offshore developers can obtain fairer access to the UK gas market. It is important that all entrants to the market have equal opportunities for market access, and these changes may have benefits in this respect.

**Unintended consequences**

71. All gas users, domestic, industrial, commercial and the public sector would benefit from increased security of supply. Firms with proposed projects will benefit from the clarity and increased certainty that the changes will offer. Environmental assessments, embedded in the process, will ensure that full account is taken of the marine environment. Increased use of gas as a fuel may improve the environment in terms of lower CO2 emissions and better air quality if it replaces oil and coal; however where it replaces renewable energy, this effect may be reversed. Care will be taken in the drafting of primary and secondary legislation to ensure that the new regime does not unnecessarily impose a burden on business.

**Consultation with small business: the Small Firms’ Impact Test**

72. Whilst we expect that the main firms directly affected are unlikely to be small, there might be some firms with innovative solutions that could be affected. In view of the aim of the new legislation, which is to provide a clearer regulatory framework for industry, we believe that proposals would result in a smaller burden for all industry than is currently the case. Initial consultation was carried out through the DEFRA Marine Bill consultation process. We have also spoken to a range of firms with existing proposals. BERR officials are in continuous dialogue with the industry to ensure that industry concerns are reflected in the way the licensing scheme is developed.
Competition Assessment

73. Storage: The UK gas storage market consists of both offshore and onshore storage. It is quite concentrated with Rough, owned by Centrica Storage, being the major player accounting for some 75% of storage capacity. However it is envisaged that changes to concerning the regulatory frameworks onshore and offshore would facilitate new entry by increasing regulatory certainty and clarity and thereby reduce the level of concentration in the storage market. These proposals would only change the regime for offshore storage; reforms to planning consents for onshore gas storage and LNG import are being taken forward in the Planning Bill.

74. The two regimes (i.e. one for offshore gas storage and one for onshore gas storage) are not currently comparable in terms of costs or requirements, but they are comparable from the perspective of entry to the GB gas market. It is important that all participants, whether onshore or offshore, can obtain equal access to the market. This will remain a consideration in the development of any new regulatory framework, so that choices are not distorted and that customers ultimately gain the benefit of the most efficient sources of gas.

75. LNG Off-loading: The upstream gas production and supply market is not concentrated, with perhaps only one or two producers having more than 10% of the market. These proposals are designed to facilitate entry and hence reduce market concentration further. It is expected that this market will be quite innovative but the proposals are designed to ensure that the widest range of projects will be covered. The proposals only affect offshore unloading. There are already on-shore facilities in the UK in place, under construction and being planned. The new offshore licensing scheme will complement the reforms of planning consents for onshore projects and encourage greater competition.

F. Enforcement

76. The new licensing scheme will be enforced by BERR Offshore Environmental inspection Team. The legislation will place a prohibition on those not licensed to store gas, or construct a platform for unloading, backed up by a criminal offence. Once a licence has been granted, it will also be an offence to breach certain of its provisions. The penalties for any person found guilty of an offence under will be a fine of up to the statutory maximum (currently £5,000, or £10,000 in Scotland) on summary conviction (in the Magistrates’ court), or an unlimited fine for conviction on indictment (in the Crown Court).

G. Monitoring & Evaluation

77. BERR will monitor the take up of licences or consents issued under the legislation and seek feedback from industry as to the regime’s efficacy. The policy will be renewed in 2011 to guarantee two full years of operation after the regulations come into force.

H. Specific Impact Tests

Competition Assessment

78. See above. The new regulatory framework puts in place a clear framework which will benefit all entrants to the market. Together with parallel reforms to facilitate planning consents for onshore gas storage, the new framework will potentially open the market up to a wider number of players.
Small Firms Impact Test

79. Small developers, insofar as they exist, will benefit from the simplified licensing regime.

Carbon Assessment

80. In the short term, no change. Longer term, if there were a shift from reliance on coal to gas (due to lower prices and increase security of supply), this could contribute to reduced carbon emissions.
### Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Carbon Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Other Environment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Health Impact Assessment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Race Equality</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Disability Equality</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Gender Equality</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Human Rights</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
Annex A – Equality Impact Tests

Race Equality: Disability Equality; Gender Equality

The reforms affect the processes for gaining consent for offshore gas storage and unloading. There are no people equality issues.
3. Competitive Energy Markets and Strengthening the Framework

One of the Energy Goals is ‘to promote competitive energy markets in the UK and beyond, helping to raise the rate of sustainable economic growth and thus improve our productivity.’ The intended effect is an independently regulated, competitive energy market that delivers energy and meets the energy goals in the most cost-effective and efficient way. To ensure a competitive market there must be a level-playing field where all those participating work to the same framework, including, where applicable, making adequate provision for decommissioning.

The policy proposals in this section of the Bill are:

- Nuclear Waste and Decommissioning
- Oil and Gas Decommissioning
- Offshore Renewables Decommissioning
- Other Oil and Gas Licensing
- Third Party Access to Oil and Gas Infrastructure
- Offshore Electricity Transmission

The Impact Assessments follow.
Summary: Intervention & Options

<table>
<thead>
<tr>
<th>Department /Agency:</th>
<th>Department of Business, Enterprise and Regulatory Reform</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title:</td>
<td>Impact Assessment of Nuclear Waste and Decommissioning financing clauses of the Energy Bill</td>
</tr>
<tr>
<td>Stage:</td>
<td>Final</td>
</tr>
<tr>
<td>Version:</td>
<td>Final</td>
</tr>
<tr>
<td>Date:</td>
<td>9 January 2008</td>
</tr>
</tbody>
</table>

Available to view or download at:

Contact for enquiries: Matthew Taylor
Telephone: 0207 215 5000

What is the problem under consideration? Why is government intervention necessary?
Companies which operate nuclear power stations may not always make the necessary provisions to cover their full costs of decommissioning and full share of waste management costs, i.e. they may not fully internalise the cost of their decommissioning and clean up obligations. This could increase the risk that the policy of ensuring the polluter pays fails. Intervention is necessary to minimise the risk of such a failure so as to ensure energy companies pay for their obligations. This policy will only affect companies if they decide, after the government has introduced the proposed legislation, that it is economically viable to invest in new nuclear. This is an investment decision for the private sector.

What are the policy objectives and the intended effects?
The policy objectives are to ensure operators of new nuclear power stations accrue sufficient funds to meet the full costs of decommissioning and their full share of waste management costs; to ensure that funds cannot be used by operators for other purposes without approval; to ensure that the funds are secure in the event of insolvency; and to ensure that responsibility for waste and decommissioning remains with the operator. These objectives are balanced against the aim to allow operators flexibility to decide how they wish to manage their liabilities within the overarching framework set down by Government.

What policy options have been considered? Please justify any preferred option.
The preferred option is that an operator is required to submit a “decommissioning programme” setting out and costing the steps that the operator will take to decommission a nuclear power station and manage and dispose of waste. Government identified the following options to achieve the overall policy objective: (1) Do nothing, i.e. rely on existing licence conditions (and international accounting standards) to ensure that decommissioning and waste disposal liabilities are fully met.; (2) Rely on HSE’s existing vires to ensure operators make provision for financing decommissioning and waste disposal; (3) Require operators to submit a Decommissioning Programme to the Secretary of State with monies for decommissioning and waste disposal paid into a funding structure (three variants were examined) to ensure that: monies are protected from insolvency situations; monies can be released reasonably quickly as and when funding is required and to ensure that monies will accrue in a clear way.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
Government will hold further consultations in 2008 on regulations/guidance that flow from powers to be taken in the Energy Bill. This will enable the policy to be reviewed and actual costs and benefits to be established.

Ministerial Sign-off

For final proposal/implementation stage Impact Assessments:

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Date: 09.01.08
## Summary: Analysis & Evidence

**Policy Option:** 3  
**Description:** Fund approach – independent funding

### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description and scale of key monetised costs by ‘main affected groups’</th>
<th>Key annual costs are likely to include creating, maintaining and administering an independent funding structure that the Government will require operators to pay monies into to cover decommissioning and waste management costs. The requirement to maintain such a body may last up to 80yrs (40yr lifetime of the plant and 40 years decommissioning).</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>One-off (Transition) Yrs</strong></td>
<td>£</td>
</tr>
<tr>
<td><strong>Average Annual Cost (excluding one-off)</strong></td>
<td>£ 1.5m (per plant) 80</td>
</tr>
<tr>
<td><strong>Total Cost (PV)</strong></td>
<td>£ 44m</td>
</tr>
</tbody>
</table>

### ANNUAL BENEFITS

| Description and scale of key monetised benefits by ‘main affected groups’ £872m (per power station) – based on central assumptions in the nuclear consultation document- Social benefit because where an operator meets the full costs of decommissioning and full share of waste management costs the £872m falls to the operator. This estimate will be further revised as cost modelling exercises are completed. The policy aims to ensure the polluter pays. It is therefore a transfer of risk from the tax payer to the operator. As a transfer, the benefit is not included in the “total benefit” box, although society/the tax payer clearly benefits. |
|---|---|
| **One-off Yrs** | £ |
| **Average Annual Benefit (excluding one-off)** | Total Benefit (PV) £ |

### Key Assumptions/Sensitivities/Risks

Estimated cost of £44m is spread over an 80yr period. The proposed approach assumes the market can absorb the investment requirements needed to support the independent fund approach.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV) £</th>
<th>NET BENEFIT (NPV Best estimate) £</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>80</td>
<td></td>
<td>-44m</td>
</tr>
</tbody>
</table>

### Key:

- **Annual costs and benefits:** Constant Prices
- **(Net) Present Value**

---

**What is the geographic coverage of the policy(option)?** England, Wales, NI

**On what date will the policy be implemented?** December 2008

**Which organisation(s) will enforce the policy?** BERR, HSE, EA, DENI

**What is the total annual cost of enforcement for these organisations?** £ Nil

**Does enforcement comply with Hampton principles?** Yes

**Will implementation go beyond minimum EU requirements?** N/A

**What is the value of the proposed offsetting measure per year?** £ 0

**What is the value of changes in greenhouse gas emissions?** £233 million

**Will the proposal have a significant impact on competition?** No

### Annual cost (£-£) per organisation (excluding one-off)

<table>
<thead>
<tr>
<th>Micro N/A</th>
<th>Small N/A</th>
<th>Medium N/A</th>
<th>Large £1.5m</th>
</tr>
</thead>
</table>

| Are any of these organisations exempt? | No | No | No |

### Impact on Admin Burdens Baseline (2005 Prices) (Increase)

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>Net Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 1.5million</td>
<td>£ nil</td>
<td>£ 1.5 million p/a</td>
</tr>
</tbody>
</table>

**Key:**

- Annual costs and benefits: Constant Prices
- (Net) Present Value
A. Strategic overview

1. This impact assessment contributes to one strand of a number of measures that will take place now that the Government has decided that new nuclear power stations should be allowed as an investment option for energy companies. This package of measures is designed to clarify issues and reduce the uncertainties in the pre-construction period for new nuclear power stations and will contribute to improvements to regulatory and planning processes. These measures include action on the justification process, strategic siting assessment and the strategic environmental assessment.

2. This action is necessary because of the long lead in times and major capital investment requirements needed to build a new nuclear power station. The industry will need to have confidence in the regulatory framework in which they will operate and know that key decisions will be made in a timely manner.

3. The report of the Energy Review from 2006, “The Energy Challenge”\textsuperscript{16} described some of the difficulties that developers could face should they wish to build a new nuclear power station in the UK. One of the major concerns raised by the energy industry was that there was a lack of clarity over the regulatory and planning process. Respondents to “The Energy Challenge” and subsequent Nuclear Policy Framework\textsuperscript{17} consultation in July 2006 commented that they would not invest in nuclear power stations unless there was action to reduce the regulatory risks or create greater certainty in specific areas.

4. The areas in which the Government will take action to reduce this risk and regulatory uncertainty include:

- Improving the planning system for major electricity generating stations in England and Wales, including nuclear power stations, by ensuring it sets a framework for development consents that gives full weight to policy and regulatory issues that have already been subject to debate and consultation at a national level, and does not reopen these issues in relation to individual applications;

- Running a SSA process to develop criteria for determining the suitability of sites for new nuclear power stations. Subject to some European legislative requirements, this would enable the planning process to focus on the proposals rather than debate whether there are other more suitable sites for development;

- In conjunction with the SSA, taking further our consideration of the high-level environmental impacts in accordance with the Strategic Environmental Assessment (SEA) Directive. This would limit the need to consider such high-level environmental impacts of nuclear power stations during the planning process;

- Running a process of Justification (in accordance with the Justification of Practices Involving Ionising Radiation Regulations 2004) to test whether the economic, social or other benefits of specific new nuclear power technologies outweigh any health detriments;

\textsuperscript{16} http://www.dti.gov.uk/energy/review/page31995.html
\textsuperscript{17} http://www.berr.gov.uk/files/file31931.pdf
• Assisting the nuclear regulators to pursue a process of Generic Design Assessment of industry preferred designs of nuclear power stations, to complement the existing site-specific licensing process. This would involve assessing the safety, security and environmental impact of nuclear power reactor designs, including waste arisings and radioactive discharges to the environment. This would limit the need to discuss these issues in depth during the site-specific licensing process;

• Working with the regulators to review the regulatory regime to explore ways of enhancing its effectiveness in dealing with the challenges of new nuclear power stations;

• Pushing for a strengthening of the Emissions Trading Scheme so that investors have confidence in a continuing carbon price signal when making a decision.; and

• introducing arrangements to ensure that operators of new nuclear power stations accrue the funds to cover the full costs of decommissioning and their full share of waste management costs.

This impact assessment deals with the final action

B. The Issue

5. In its energy strategy the Government has stated that the two challenges the UK faces in developing energy policy are tackling climate change and ensuring the security of energy supplies. Government has said that it will meet these challenges by:

   a. Saving energy;
   b. Developing cleaner energy supplies; and
   c. Securing reliable energy supplies at prices set in competitive markets.

6. The Government’s consultation on the future of nuclear power\textsuperscript{18} set out the role that any new nuclear power stations could play in contributing to providing solutions to these two challenges. The Government believes that nuclear has a role to play in reducing carbon emissions, alongside other low carbon technologies. For example the annual carbon emissions reduction from investing in a GW of nuclear plant is approximately 2.6 million tonnes of CO\textsubscript{2} (around 700,000 tonnes of carbon) compared with investment in a gas-fired power station. This figure includes allowing for emissions from construction of nuclear power stations and mining / processing uranium (“lifecycle emissions”). As an illustrative figure, 6GW of new nuclear capacity could reduce annual emissions by around 16 million tonnes of CO\textsubscript{2} (around 4.3 million tonnes of carbon).

7. Carbon emissions reductions can be monetised using a carbon price, which can be regarded as a proxy for marginal emissions abatement cost. Valuing emissions savings at the shadow price of carbon in 2007 of €35 (or £25) per tonne of CO\textsubscript{2} would give a NPV benefit of around £1.4billion over forty years from nuclear new build of 6GW or £233m per GW\textsuperscript{19}. If new nuclear power station is added to the energy system, abatement costs elsewhere in the economy are reduced in order to meet a given overall target for carbon reduction. The reduction in abatement cost may be regarded as a benefit associated with

\textsuperscript{18} The Role of Nuclear Power in a Low Carbon UK Economy, DTI, May 2007

\textsuperscript{19} (Nuclear Power Generation Cost Benefit Analysis, DTI, 2006)
nuclear generation to be offset against any nuclear cost penalty (i.e. the additional cost penalty of nuclear power generation above gas-fired power generation).

8. This argument applies as long as a commitment to carbon emissions reduction remains. If commitment were to fall away, there would be less onerous targets for carbon emissions reduction, with lower related abatement costs. At the extreme where there is no commitment to carbon reduction and no abatement activity, there would be no abatement cost saving for nuclear generation.

9. The Government’s policy and the economic case for new nuclear is set out in The Energy White Paper 2007, the nuclear consultation document and the 2008 Nuclear White Paper. As a result this impact assessment does not cover those arguments already set out there but instead describes the range of options that were investigated when developing a framework that would ensure that an operator would accrue the full costs of decommissioning and their full share of waste management in a clear way; ensure that funds cannot be used by the operator for use on anything other than decommissioning and waste management and also ensure that the monies set aside can be protected in the event of an operator becoming insolvent.

10. Arguably, the policy being pursued in this impact assessment is not a new one. It is the Government’s principle that the polluter should pay and examples of this principle can be found in activities across the energy sector such as in the decommissioning of offshore installations. However the much larger scale (in terms of both cost and time) of dealing with nuclear waste and decommissioning liabilities means the arrangements that the Government is putting in place need to be a proportionate response when compared to the policies already in place for other forms of energy infrastructure decommissioning projects.

C. Objectives

11. The primary objective of this policy is to ensure that any potential new nuclear power station operators meet the full costs of decommissioning and their full share of waste management costs. Government has said that if there were to be new nuclear power stations in the UK then the Government would put in place a robust structure according to the following principles20:

Decommissioning principles

a. There should be an upfront assessment of decommissioning costs;

b. Full responsibility for decommissioning costs is to be retained by the private sector operator(s);

c. Protection will be given to the public sector regarding credit risk and reduced reactor life;

d. The framework should be robust and transparent through time;

e. That these principles will form the basis of arrangements which will apply consistently to all new build operators and reactor types.

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20 The Role of Nuclear Power in a Low Carbon UK Economy, DTI, May 2007
Waste management principles

f. Delivering and paying for the construction of a long-term waste management solution for legacy waste is a responsibility that falls to the public sector. Any such long-term waste management solution developed by Government would factor in waste from new build;

g. There will be an assessment of how new build affects the cost of delivering the national waste management solution;

h. The private sector will pay a charge covering the full share and equitable costs of managing the waste generated over the expected life of each new power station. The level of this charge will be informed by work on the Government’s long-term waste management solution;

i. The commercial nature of the arrangements in relation to waste disposal will incentivise participants to operate power stations in a way that seeks the optimal balance between performance and waste generation;

j. Protection will be given to the public sector regarding changes in reactor life;

k. Provision of interim storage over the life of the plant will be the responsibility of the operator;

l. The framework should be robust and transparent through time;

m. These principles will form the basis of arrangements which will apply to all new nuclear build operators and reactor types.

12. For the purposes of this impact assessment it is assumed that a new nuclear plant would have a 40 year lifespan and a 40 year decommissioning period. It is expected that a funding structure as described under the preferred option paragraph would be in existence for the totality of this period. This is because the funding structure’s role would be to accrue monies until the power station ceases to generate electricity and then to ensure that monies leaving the funding structure are being spent in accordance with the decommissioning programme once decommissioning starts.

D. Options Identified

13. To achieve the overall policy objective the Government considered a number of options. These were:

<table>
<thead>
<tr>
<th>Option Number</th>
<th>Proposal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>Do nothing, relying on existing licence conditions and accounting standards to ensure decommissioning and waste disposal liabilities are met.</td>
</tr>
<tr>
<td>Option 2</td>
<td>Rely on existing vires for HSE to make new requirements of operators, to ensure financing for decommissioning and waste disposal overseen by the HSE.</td>
</tr>
<tr>
<td>Option 3</td>
<td>Funded Decommissioning Programme</td>
</tr>
<tr>
<td>Option 3a</td>
<td>Within company funding (monies ring fenced on the company’s balance sheet)</td>
</tr>
<tr>
<td>Option 3b</td>
<td>Payments direct to Government over life of the power station</td>
</tr>
<tr>
<td>Option 3c</td>
<td>Independent structure i.e. a trust fund, contributions from the operator who is the ultimate beneficiary but not owned by the operator, with governance of the fund outside of the operator’s control</td>
</tr>
</tbody>
</table>
E. Analyse the Options

Option 1. Do nothing

14. Under this approach operators would not be required to set aside monies for liabilities by law and the sole requirement would be to ensure that they could fulfil the conditions under Licence 35 (see Option 2 for further detail on Licence 35 conditions) and reflect these liabilities in their accounting information in accordance with established accounting procedures. Although the operator would still be required to meet the full costs of decommissioning and their full share of waste management costs. It was felt that in practice this would be able to mean that the operator would show the costs of waste management and decommissioning as a liability on the balance sheet and that as long as they could show assets to match those liabilities then it would be assumed that the operator would have the funds to pay for waste and decommissioning.

Benefits/Costs

15. Benefits – such an approach would make for a light touch regulatory regime with little or no increase to the existing regulatory burden other than ensuring that costs of decommissioning and waste management were built into investment strategy when applying for a licence to operate.

16. Costs – Ultimately where the operator failed to ensure that its assets covered its liabilities the cost of decommissioning could fall to the taxpayer to ensure the protection of the public and the environment. This is because this approach would not place an adequately robust regulatory requirement upon the operator to demonstrate that it could cover its liabilities so there would be no sanction in the event the operator failed to do so.

Risks

17. Under this approach the Government could not guarantee that operators would ensure that they could cover the immediate or future waste and decommissioning costs.

Option 2. That the HSE would absorb the responsibility for ensuring that operators accrued funds to meet waste and decommissioning costs under existing vires.

18. Under the Nuclear Installations Act 1965 the HSE has powers to attach certain conditions to site licences. The licences define the areas of nuclear safety to which an operator should pay particular attention to ensure the safe operation of the site. Some licences impose specific restrictions whilst others require the licensee to devise and implement specific arrangements. These may cover the design, siting, construction, commissioning, operation, and modification through to eventual completion of decommissioning.

19. Licence 35 covers decommissioning and requires the licensee to have particular arrangements in place for the safe decommissioning of the facilities. The licence conditions also give the HSE the power to direct the holder of the licence to commence the decommissioning of any plant or facility, to prevent it being left in a dangerous condition or to ensure decommissioning takes place in accordance with any national strategy. The licence conditions also give the HSE the power to halt any decommissioning activities. Licence condition 33 gives it the power to ensure that waste stored on site is disposed of safely as it may specify and in accordance with an

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21 As well as reclaiming costs associated with inspections of nuclear installations.
authorisation issued by the Environment Agency (or the Department of the Environment in Northern Ireland) under the Radioactive Substances Act 1993.

20. Under this option HSE would use existing vires to ensure that operators meet the decommissioning requirements under Licence 35 and that disposal is carried out in accordance with any specification under licence condition 33. They would also have been given the additional responsibility for ensuring that operators had made provision for the full funding of the waste management and decommissioning of the plant or facility. Whilst this is similar to Option 1, the key difference is that under this option, the HSE would take on the responsibility of ensuring that not only were safety requirements met, but that the financing requirements to meet the full costs of waste management and decommissioning were in place and monies accrued accordingly.

Cost/benefit

21. Under this option the responsibility for ensuring that the operator accrued monies to fund their full share of waste management costs and full costs of decommissioning would have fallen to the HSE. It was felt that creating this role for the HSE was likely to be a distraction from the HSE’s primary regulatory function of safety.

Risks

22. The risks under this option were raised early on in discussions with HSE. Their concerns were around potential conflicts of interest between assessing both the technical route to decommissioning and the operator’s investment strategies for accruing monies to meet their full share of waste costs. HSE’s focus and expertise rests in health and safety and not in commercial and financial matters.

23. Having reviewed these options and assessed them as not fit for purpose a third option was developed that grew into the Government’s preferred option. As part of the preferred option government assessed three alternative models for ensuring that operators met their full share of waste management costs and full share of decommissioning costs. These sub-options are described below.

Options 3a, 3b, 3c - Background

24. Under these options an operator would be required to submit to the Secretary of State a Funded Decommissioning Programme which would consist of a technical plan (see Annex A) setting out proposals for decommissioning a plant and managing its waste and a financial plan (see Annex B). The financial plan would contain information setting out how the operator will meet the costs of the actions set out in the technical plan. The content of the technical plan would be referenced to a “base case” which will be developed by Government. The Funded Decommissioning Programme will be separate from the licensing requirements that operators will have to achieve under existing legislation because its core function is a financial one to ensure operators accrue the necessary funds to meet the full costs of decommissioning and their full share of waste management costs. However to minimise the regulatory burden our intention is that an operator will be able to submit a technical plan as part of its safety case in the site license application to the HSE.

Nature of fund structure

25. Government investigated a number of structures whose purpose was to ensure that monies could be accrued in a way that fulfilled the decommissioning and waste management principles set out in the objectives section of this impact assessment. The
structures investigated by the Government were: “within-company” funding; payments to a fund controlled by government; and payments to a fund independent of the operator and government. These are discussed in detail below.

**Option 3a - within company funding**

26. This option i.e. one controlled by the company, is an approach used elsewhere in Europe. Funds are directly managed by the operator and the liabilities are shown as provisions on the operator’s balance sheet. In practice the funds might be reinvested within the business to develop other assets which in turn provide a cash flow to pay for waste management and decommissioning costs at a later date. Operators have tended to favour this approach as it allows for the revenue to be reinvested in the business.

**Benefits/costs**

27. This initially appeared to be an attractive fund structure; it is a method used for generating funds that is already in use by some operators who are also responsible for the means of meeting the liability, backed up with a guarantee from the operator to underpin the liabilities. For Government, the key benefit of this option is that the fund and the liability would fall firmly with the operator.

**Risks**

28. With this approach the key concern was that there was still a risk that sufficient funds would not, in practice, be available. In particular, in a company undergoing a restructuring programme, the assets could be diverted and be made unavailable to fund the liability. It was felt this could ultimately mean that Government might be called on to meet the cost of clean up. This approach also relies on the continuing successful growth of the company to fund liabilities from future cash flows. If the operator were to go into liquidation the funds are unlikely to be available to cover the costs of liabilities.

**Option 3b - payments to Government**

29. Under this option, the operator would make payments into an external fund which is in turn administered by Government or direct to the Government’s Consolidated Fund.\(^2\)

**Benefits/costs**

30. The key benefit of this approach is the security of the structure over time; there are few institutions as long lived or credit worthy as national governments. However whilst the sustainability and reliability of the Government as the holder of the funding structure is attractive, the downside is the low rate of return when compared with other investment options. For example, looking historically at the real returns on gilts there has been approximately a 1% return, whereas for equity, the assumed return has been around 4%. It is evident that for operators, contributions would have to be much higher to grow (compounding) to the same target amount over a 40 year period. Additionally whilst this option may appear attractive in terms of security, for any potential operator it would have required a higher level of payments into the structure.

\(^2\) In Sweden such funds are invested in the Swedish Nuclear Waste Fund and in Spain they are managed by the state waste disposal company ENRESA. Finland and Belgium have a hybrid arrangement whereby the licensee can borrow back a percentage (usually 75%) of the contributions to the fund at a commercial interest rate. The US approach to spent fuel management also falls into this category, whereby the Operators make a $1 per MWh payment to the Federal Government to cover disposal costs.
Risks

31. The risks of this option include:

a. Funds held in the public sector are likely to assume a low, risk free, rate of return which could increase the overall cost to the operator of providing for liabilities significantly;

b. Less transparency than separate independent structures;

c. The possible public perception that Government is taking on the liability and removing risk from the operator whereas policy is that new build operators are responsible for paying the full costs of decommissioning and their full share of waste management costs.

Option 3c – Independent fund

32. Under this option the operator would be required to set up an independent structure in which the monies required for waste management and decommissioning would be accrued. Structures would have to be protected from insolvency.

Benefits/costs

33. The main benefits of this approach are that it is transparent and consistent with the policy of ensuring that energy companies, not Government, take full responsibility for meeting the costs of decommissioning and waste management and disposal. These independent funds would be insulated against the commercial fortunes of the operator and only available to pay for qualifying clean up costs. The funds would be invested prudently and could be liquidated reasonably readily as required to discharge the liabilities stemming from waste and decommissioning.

34. The Government will set the principles that an approvable funded decommissioning programme must comply with in legislation and guidance. Within these principles, Government will aim to allow companies maximum flexibility to design their funding structures. Examples of these principles might include:

- prescribing that the funding structure must be independent, i.e. outside of the control of the operator,

- placing restrictions on the use of the funds to prevent them being used for any purpose other than decommissioning and waste management; and

- putting in place a system of regular monitoring and review of the payment schedule.

35. At this stage it is difficult to estimate what the costs of submitting a funded decommissioning programme to the Secretary of State are likely to be as the management costs associated with the decommissioning and waste management plans of existing nuclear power stations are not directly comparable. The administrative costs for the Nuclear Liabilities Fund are in the region of £1.5m pa, and therefore we consider that this figure is a reasonable proxy.

36. An operator may be able to enjoy some economies of scale if co-locating the monies related to more than one site in a single structure, but it is likely that the monies for each power station will have to be separately monitored, scrutinised and recorded in a report for any review conducted by the Secretary of State.
Risks

37. There is a risk that due to fluctuations in the stock market, the monies may not accrue according to the investment strategy. However, Government believes that this can be mitigated by targeting the fund at greater than 100% of expected costs to build in a contingency, ensuring that the investment principles that each operator proposes are prudent, the regular monitoring of the size of the fund relative to the liability through regular reviews allowing for the contribution rate to be modified, and ensuring that operators swap to a low risk portfolio towards the end of the investment life.

F. Enforcement

38. The responsibility for enforcing, monitoring and in the event of non-compliance, imposition of sanctions in relation to the decommissioning programme will be the responsibility of BERR. The proposed legislation sets out the powers that the Secretary of State will have to approve decommissioning programmes, ensure compliance, monitor, require remedial action if required, charge a fee for any costs incurred in obtaining any information in relation to the decommissioning programme and ultimately seek redress in the courts.

G. Implementation

39. This legislation will become effective when the Bill receives Royal Assent but will not impact upon industry until an operator puts forward proposals to build a new nuclear power station.

H. Monitoring and evaluation

40. Operators will be required to submit a report to the Secretary of State setting out the status of the decommissioning programme on a regular basis. Further monitoring of the policy will take place on a case-by-case basis including when amendments are proposed to a funded decommissioning programmes are reviewed. This may lead the Government to modify guidance as the industry develops and progress allows us to reflect on lessons learned and best practice developed by companies.

I. Specific Impact Tests

Human Rights

41. The only impact test relevant to this policy is the Human Rights impact test. This has been taken into consideration during the drafting of the required legislation which has been worked on, on a contingent basis and set out in the ECHR Memorandum.
### Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Carbon Assessment</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Other Environment</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Health Impact Assessment</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Race Equality</td>
<td>Yes</td>
<td>N/A</td>
</tr>
<tr>
<td>Disability Equality</td>
<td>N/A</td>
<td>Annex C</td>
</tr>
<tr>
<td>Gender Equality</td>
<td>N/A</td>
<td>Annex C</td>
</tr>
<tr>
<td>Human Rights</td>
<td>N/A</td>
<td>Annex C</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Annexes

Annex A – Guidance on the technical plan
Annex B – Guidance on financing arrangements
Annex C – Equality Impact Tests
Annex A – Guidance on the technical plan

The Government will set out and publish in guidance a prudent means for waste management and decommissioning. This means will be called the “Base Case”. The Base Case will represent a prudent way to estimate the costs of waste management and decommissioning and will inform operators as to what an approvable decommissioning programme would look like. The types of areas that could be set out in the guidance may include:

- The need for operators to provide interim waste storage facilities, capable of being maintained or replaced to contain waste for an extended period of time until we expect a geological disposal facility to be in a position to accept waste from new nuclear power stations and beyond that date to provide some contingency;
- The treatment and disposal of low level waste;
- How soon decommissioning would take place after station closure; and
- When and on what terms we would assume that waste could be transferred to a geological disposal facility.

Operators will need to have regard to the Base Case when developing a decommissioning programme, although there will be flexibility to allow operators to suggest alternative approaches if they wish to do so. Alternative approaches may or may not be approved by the Secretary of State.

The guidance will be subject to reviews which will ensure that its content remains up to date with the latest developments in waste handling and decommissioning costs.

Government will consult on this work in 2008.
Annex B – Guidance on financing arrangements

- Guidance and regulations will set out the information that a nuclear power station operator must take into account when preparing proposals for accumulate funds to cover the costs of decommissioning and waste management and disposal. The proposals put forward by the operator as part of its ‘funded decommissioning programme’ must be approved by the Secretary of State for Business and Enterprise. Examples of areas that might be covered are set out below:
  a. The structure of a Fund in which to accumulate monies;
  b. How the fund will be governed;
  c. The investment principles for the fund;
  d. Proposals and arrangements for contributions to the fund;
  e. Target value for the fund and the timescale within which the fund should reach that target;
  f. How the fund size and performance will be monitored and audited;
  g. The basis for repairing a deficit in the fund;
  h. Arrangements for dealing with any disputes that might arise relating to the fund;
  i. What additional securities (such as parent company guarantee, insurance or financial instruments) will be in place to ensure that the costs of decommissioning and waste management and disposal are covered even if the fund proves insufficient (for example if the power station closes early and the liabilities crystallise before the fund is mature);
  j. Circumstances in which payments would be disbursed from the fund, and how those payments would be disbursed;
  k. Arrangements for the disbursement of any surplus funds after decommissioning is complete.

There will be flexibility to allow operators to suggest alternative approaches if they wish to do so, for the consideration of the Secretary of State. Alternative approaches may or may not be approved by the Secretary of State.

The guidance may be periodically reviewed to ensure that its content remains up to date with the latest best practice.

Government will consult on this work in 2008.
Annex C – Equality Impact Tests

Race Equality

This policy does not impact upon this area because it involves the creation of a new framework for the operators of any new nuclear power station.

Disability Equality

This policy does not impact upon this area because it involves the creation of a new framework for the operators of any new nuclear power station.

Gender Equality

This policy does not impact upon this area because it involves the creation of a new framework for the operators of any new nuclear power station.
What is the problem under consideration? Why is government intervention necessary?
The problem under consideration is that if the company responsible for decommissioning offshore oil and gas installations and pipelines defaulted, international obligations and public expectations mean that the Exchequer (and therefore taxpayers generally) would have to bear the cost of decommissioning. Intervention is needed to help to ensure that the costs of decommissioning offshore installations and pipelines are borne by those responsible for them.

What are the policy objectives and the intended effects?
The aim is to ensure that all those responsible for an installation or pipeline carry out their statutory responsibility for its decommissioning and that in high risk cases financial security is provided to protect the taxpayer throughout the life of the oil or gas field, even if the companies go into liquidation.

What policy options have been considered? Please justify any preferred option.
Option 1. Do nothing - leaves the taxpayer increasingly exposed to risks of up to £300m per structure.
Option 2. Security to be provided in high risk cases - a reasonable balance between the risk and the costs to industry - the preferred option.
Option 3. Security to be provided for all cases - the strongest protection for the taxpayer, but unreasonable costs for industry and probably would result in much lower oil and gas production.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
Within 2 years of implementation

Ministerial Sign-off For final proposal/implementation stage Impact Assessments:
I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Date: 09.01.08
### Summary: Analysis & Evidence

**Policy Option:** 2  
**Description:** Security in high risk cases

#### ANNUAL COSTS

| Description and scale of key monetised costs by 'main affected groups' | Additional financial security costs of £2,500,000  
admin & legal £140,000  
| Govt - admin & legal £50,000 which totals £2.69m as the estimated administration cost per installation |

**One-off (Transition)**  
**Yrs**  
**£ none**

**Average Annual Cost**  
(excluding one-off)  
**£ 2.69m**  
**30**  
**Total Cost (PV)**  
**£52 million**

**Other key non-monetised costs by 'main affected groups'**  
some companies will have increased contingent liabilities; loss of access to segregated funds for general creditors; no significant social or environmental costs

#### ANNUAL BENEFITS

| Description and scale of key monetised benefits by 'main affected groups' | There is a decreased risk of the cost of decommissioning defaulting to Government – and the taxpayer – as the risk is transferred back to the company. It is not feasible to predict benefits for the taxpayer/exchequer on an annual basis as they could occur at any time, however estimated defaults could be anything between £5m and £300m for each installation (this range is based on the default estimated costs of Ardmore at the lower end and Fairfield at the higher end). As a transfer this will not be counted in the Total Benefits. |

**One-off**  
**Yrs**  
**£**

**Average Annual Benefit**  
(excluding one-off)  
**£**  
**Total Benefit (PV)**  
**£**

**Other key non-monetised benefits by 'main affected groups'**  
The reduction in contingent liabilities for some companies;

---

### Key Assumptions/Sensitivities/Risks

Four developers of new fields have to put up security each year at a cost of up to 3% plus cash collateral costs of 7% of the value of security i.e the NPVs of estimated cost of decommissioning less future revenues. It is estimated that eleven companies could possibly default in next 30 years leaving the taxpayer to fund costs between £25m and £230m.

#### Price Base

<table>
<thead>
<tr>
<th>Year</th>
<th>Time Period</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>Years 30</td>
<td>£-52 million</td>
<td>£ -52 million</td>
</tr>
</tbody>
</table>

**What is the geographic coverage of the policy/option?**  
UK

**On what date will the policy be implemented?**  
2008

**Which organisation(s) will enforce the policy?**  
BERR

**What is the total annual cost of enforcement for these organisations?**  
£ 50k

**Does enforcement comply with Hampton principles?**  
Yes

**Will implementation go beyond minimum EU requirements?**  
No

**What is the value of the proposed offsetting measure per year?**  
£

**What is the value of changes in greenhouse gas emissions?**  
£ nil

**Will the proposal have a significant impact on competition?**  
No

<table>
<thead>
<tr>
<th>Annual cost (£-£) per organisation (excluding one-off)</th>
<th>Micro</th>
<th>Small</th>
<th>Medium</th>
<th>Large</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>nil</td>
<td>£2.69m</td>
<td>£2.69m</td>
<td>£2.69m</td>
</tr>
</tbody>
</table>

| Are any of these organisations exempt? | No | No | N/A | N/A |

### Impact on Admin Burdens Baseline (2005 Prices)

| Increase of | £ 50k | Decrease of | £ nil | Net Impact | £ 50k |

**Key:**  
Annual costs and benefits: Constant Prices  
(Net) Present Value
A. Strategic Overview

Petroleum Act 1998 Part IV – Abandonment of Offshore Installations

1. This Impact Assessment (IA) considers the potential impacts of a proposal to amend the provisions of Part IV of the Petroleum Act 1998. These provisions relate to the Secretary of State’s powers to ensure that adequate financial arrangements are put in place to carry out an abandonment programme for offshore oil and gas installations.

B. The Issue

2. Part IV of the Petroleum Act 1998 (which consolidates the relevant sections of the Petroleum Act 1987) is intended to ensure that companies responsible for the presence of oil and gas facilities in the marine environment carry out the decommissioning of those structures when they are no longer in operation. When the legislation was drafted in the 1980s, most developments were in the hands of major oil companies. In recent years there has been significant trading of UK oil and gas assets from large companies to smaller companies. The introduction of innovative licensing schemes designed to attract smaller investors has also brought a number of new companies to the UK Continental Shelf (UKCS). To meet the challenge of declining gas production from the UKCS there is considerable market interest in projects to enable gas to be stored offshore, and to enable liquefied natural gas to be imported to UK waters and unloaded into offshore facilities. Whilst wishing to encourage these activities, the Government also has a duty to ensure that the taxpayer is not exposed to an unacceptable risk of default in meeting the costs associated with the decommissioning of offshore installations and pipelines. The two aims must be carefully balanced.

3. The Government ensures that redundant facilities are decommissioned by serving notices under section 29 of the Petroleum Act 1998 on those persons with an interest of a kind set out in section 30(1) and 30(2) in respect of each offshore installation or each pipeline. Section 29 notices require the recipient to submit a decommissioning programme at such time as the Secretary of State may call for it. The obligation to carry out an approved decommissioning programme is joint and several. This means that if any one of those with a duty to carry out a programme is unable to do so, the other interested parties will be responsible for the defaulting party’s share. In addition, under section 34 of the Act, a company which had previously held an interest in an installation or pipeline may in certain circumstances be ‘called back’ and placed under a duty to carry out a decommissioning programme. The Secretary of State currently has a limited power to require companies to put up financial security if he is concerned about their ability to carry out a decommissioning programme, but this provision only applies once a programme has been approved. As it is the practice to draw up programmes at the end of the life of a field, the Secretary of State cannot currently require security under the Act before that time.

4. For installations, notices may be served on licensees, the company that manages the installation, the owners, and the parties to a Joint Operating Agreement. For pipelines, notices are served on the owners. Notices under section 29 may also be served on parent or associated companies where it is judged that satisfactory arrangements, including financial, are not being put in place to ensure that a decommissioning programme will be carried out.
5. There are generally two instances when the Department needs to make a judgement on the ability of companies to carry out decommissioning: either at the time of an assignment of interests in a licence affecting an existing field or at the time of submission of a development plan for a new project.

6. When a company sells a licence interest to another company, the Department would normally be minded to serve a section 29 notice on the new party. It will carry out a financial assessment to gauge whether the new group of licensees looks capable of meeting its decommissioning obligations. If there is concern that the group will be weakened by the departure of the selling company it is unlikely that the Secretary of State will exercise his discretion to withdraw the section 29 notice from the selling company. In these circumstances, the selling company often requires the buyer to provide a financial guarantee under a security agreement. The companies may also decide to invite the Secretary of State to become a party to the agreement; this will provide security for the taxpayer and the decision not to withdraw the section 29 notice from the selling company may then be reversed. There has been an industry initiative to develop a standard template for security agreements which was recently finalised. The aim has been to establish a model that will ensure that guaranteed funds (which may include future revenues in appropriate cases) will be available to cover decommissioning costs at all times and which can be endorsed by all parties.

7. When a developer puts forward proposals to the Department for development of a new oil or gas field, we assess the financial strength of the companies involved. If we have concerns about their ability to meet the cost of decommissioning we currently have no legal powers to require security at that point in time. The company may recognise the Department’s concerns and offer to provide security, usually in the form of a letter of credit. But we cannot enforce this action. To encourage voluntary action, the Department will suggest that the security need only cover the initial risk until it can be demonstrated that the reservoir will produce the expected revenues; security may also be required towards the end of field life as production and revenues decline.

8. Securities usually take the form of letters of credit for which the issuing bank will charge a fee ranging from 0.5% of the value for a major company to 3% for a small company with few assets. The bank will require an indemnity or cash collateral and the letter of credit will be set off against the total credit the bank is prepared to allow the company. We have been advised by one company that providing cash collateral equal to the amount of the security adds a further 7% of the value to the costs.

Consultation

9. For a number of years, consultations with the industry have been conducted within a government/industry task force “PILOT” and in informal contact with smaller developers. A group of smaller companies and their trade association was consulted last year and 8 companies have recently been consulted individually on a confidential basis about their experiences in negotiating transfers of licence interests. In addition, a full public consultation was also undertaken. This closed on 13 September 2007. This assessment takes account of information received.

C. Objective

10. To strengthen the Government’s ability to ensure that those responsible for offshore installations and pipelines can afford to remove them at the end of their life. The aim is
to minimise the risk that companies default on their decommissioning obligations leaving the tax payer to meet the costs.

11. The measures will affect companies responsible for existing offshore oil and gas facilities and those which develop new oil and gas fields or offshore gas storage or recovery infrastructure. The provision of security will only be necessary where we have concerns about the financial strength of the parties involved.

Devolution

12. It is proposed that the amendment to the Petroleum Act proposed in the Energy Bill will apply, like the original provisions of the Petroleum Act 1998, to all of the UK territorial waters and the UK Continental Shelf (UKCS).

D. Options Identified

13. We have considered the following options:

- Option 1: No change;
- Option 2: Amend the legislation to provide Government with the ability to require security when the risks of default are unacceptable, to ensure all relevant companies bear the decommissioning liability and to protect security funds from insolvency proceedings.
- Option 3: Require financial security in all cases; ensure all relevant companies bear the liability and protect funds from insolvency proceedings.

E. Analyse the Options

Option 1:

14. No change. Taking no action continues to expose us to an increasing risk that companies will default on their decommissioning obligations, particularly with new field developments involving smaller companies. As existing powers to require financial security are limited by the 1998 Act to the period after approval of a decommissioning programme, which is towards the end of field life, we would have to depend on companies voluntarily putting up financial security at the start of a field development or at any subsequent vulnerable stage. This is unlikely to be effective in protecting the taxpayer as there is little incentive to encourage companies to pay for security voluntarily.

Costs and Benefits

15. The do nothing option would not add to current industry costs but the potential costs to the taxpayer will grow due to the increasing number of smaller companies active on the UK Continental Shelf (UKCS). One industry study of decommissioning liabilities in July 2006 used credit rating agency data to support an estimate that 11 companies could potentially default in the next 30 years and that the decommissioning costs involved could be between £25 million and £230 million, after taking account of the defaulting companies’ potential assets and future revenues. This option also carries a resource cost to the Government in handling default situations; in the Ardmore case (see paragraph 32) this has amounted to 450 staff/days at a cost of at least £225,000 to date.

16. Not tackling the gaps in powers to make all relevant companies liable for decommissioning leaves those companies which do have the liability carrying an
increased share of the burden. If segregated funds are established for decommissioning liabilities but are liable to be taken over by an insolvency practitioner for distribution to general creditors, the Government may have to step in to pay for the work. Whilst the probability of companies becoming insolvent is low the likelihood that insolvency practitioners would attempt to access any segregated funds is generally seen as high and the industry sees this as a serious risk and has put considerable legal resource into drafting a model security agreement which will protect any funds from insolvency procedures. It is uncertain whether this model will be effective and difficult to establish any reasonable basis for quantifying this risk.

**Option 2:**

17. To ensure that the taxpayer is better protected against the increasing risk of default on decommissioning liabilities, we would extend the current provision of section 38 of the Petroleum Act to enable the Secretary of State to require security when the level of risk is judged to be unacceptable. The risk in each case would be calculated by assessing the financial strength of the companies concerned and comparing that to the decommissioning costs for the field in question as explained in paragraph 31. The 1998 Act would be amended so that cost information could be acquired when the risk first arises. The procedures used would be published to enable companies to understand the financial assessments and, if they wish, to determine in advance what the likely security costs would be for a potential project.

18. We would introduce a provision to ensure that funds put aside for decommissioning would be retained for that purpose if a company became insolvent and would not be taken for distribution to the company’s creditors. We recognise that potential investors in companies with oil and gas interests should be aware of this position, and as such a company will be required to publish information about funds set aside for decommissioning. We will also draw attention to this issue in our Guidance Notes for Industry.

19. Business practices on the UKCS have evolved since the original Act of 1987 and experience of implementation has shown that liabilities cannot always be shared fairly amongst all the companies responsible for the installation or pipeline. Spreading the liability reduces the burden on individual companies and the risk of default and we therefore propose to make the following liable, where appropriate:

- persons within the scope of section 30(1)(b) and (c) i.e. licensees and others with an interest when activity is intended to be carried on from an installation; the existing power only captures such persons after the oil or gas production activity has started;

- persons owning an interest in an installation, i.e. persons within the scope of section 30(1)(d) even if the Secretary of State might be satisfied with arrangements made by other persons, i.e. within section 30(1)(a) to (c). As an example, floating production systems may be owned by companies other than the licensees and may change hands occasionally. The initial owners are made liable for the removal of these facilities when the field development is approved, but the constraint in section 31(1) means that if the facility is sold whilst on station, the new owner cannot be made liable for its removal if the licensees are seen as able to afford the decommissioning. In effect, the legal liability for removing the floating facility lies with the users but not its new owner, which seems unreasonable;
• the corporate members of Limited Liability Partnerships (LLPs).  If the Secretary of State is concerned that a company may not be able to meet its decommissioning liabilities he can spread the obligation to its associate companies, e.g. a parent company.  It is uncertain whether this provision would apply to the corporate members of LLPs and it would provide clarity for industry and government if this uncertainty was corrected by bringing corporate members of LLPs clearly within the scope of the provision;

• persons who own or have an interest in a pipeline or are associated with such a company from the time at which they intend to establish the pipeline rather than after it has been established as in the current legislation, i.e the definition of pipeline (section 45) It should be possible to establish decommissioning liabilities for a pipeline once construction starts;

20. In addition, the Secretary of State is required to act reasonably in serving section 29 notices establishing decommissioning liabilities. To ensure he does so, he must be able to resolve any concerns about the financial position of a company. Creating a legal liability by serving a notice might in some cases have a serious impact on the viability of the company. However, the existing provision enabling the Secretary of State to obtain financial information (s38(1)) cannot be used before the serving of a notice; it is proposed that this provision be extended to cover the period prior to serving a notice to avoid the above concern.

Costs and Benefits

21. Information has been gathered on the new development projects approved by BERR for the 2 years from August 2005. Of the 53 projects considered, 7 would be regarded as higher risk under the assessment process mentioned at paragraph 31 below. The 7 cases involved estimated decommissioning costs of £50 million. Security would cost up to 3% of the value in bank fees plus 7% for the cost of cash collateral plus perhaps 0.25% for admin and legal work, which on £50m equals a total cost of around £5 million or £2.5 million a year. This figure would be reduced as security would usually be calculated after allowing for future revenues. However some projects under discussion are larger so on balance we have left the assumption at £2.5 million a year. Companies would also incur administrative and legal costs which we estimate at £40,000 a year per project i.e. an average of £140,000 a year (based on 3.5 projects per year).

22. We may also require security when a larger company sells its interest in an existing field to a smaller company with fewer financial resources. 17 asset sales were recorded by Wood Mackenzie in 2006 and security might be required in perhaps half of those with typical decommissioning costs of perhaps £25 million for the new company’s share. This would suggest a total cost for security to the industry of £8 million (10 cases @ £25m x 3%). However the sellers of such interests will already require the buyers to put up security under standard commercial practice so our proposals would not increase costs in these cases. Indeed, we understand that when a new company joins a licence group it may have to put up security for more than one of its new partners; this can result in duplication of securities. We envisage that if the new company provides security under a legal requirement, those partners would not need additional guarantees. It is therefore likely that there will be no overall increase in security costs to the industry for asset trades; indeed, the costs may actually be reduced.

23. Letters of credit can have an impact on companies by reducing the amount they can borrow from their bank and thus the amount they can invest in developments. The impact on companies will be dependent on their standing with their banks and their
Companies with very limited resources may have to provide cash collateral to back a letter of credit. The Department is therefore encouraging the use of other security instruments such as bonds or trust funds which do not have the same impact on a company’s ability to borrow funds.

24. The proposals (at paragraph 19) concerning the timing and sharing of liabilities and the protection of segregated funds should not add significant costs to the industry overall, either because they will be negligible or because any increase in the costs of managing contingent risks for one company will be balanced by a reduction in costs of its licence partners.

25. The benefit of this option is that the taxpayer would have a high level of protection from contingent liabilities of at least £5 million per project. We believe that costs to the industry of our proposals of perhaps £2.7 million a year are not unreasonable when compared to these contingency levels and the overall capital expenditure of the sector, e.g. £5.6 billion in 2006. There will be social benefits from this option as it will reduce their risks of the costs of decommissioning projects falling to the public purse; if BERR had to meet the liability its support for business budgets might have to be reduced to meet the liability. This option is the Department’s preferred choice.

**Option 3:**

26. We could amend the 1998 Act as for Option 2 but require decommissioning security to be put in place in all cases regardless of the financial strength of the participants. This would apply to new developments for the life of the field as well as for asset sales where the section 29 decommissioning liability would be retained on any exiting company.

**Costs and Benefits**

27. This option would impose the greatest cost burden upon the industry but would provide the highest level of certainty that decommissioning costs would be met. The costs to industry would rise substantially as a result of the need to provide security in all cases. As the overall decommissioning costs for the UKCS are estimated to be between £15 billion and £19 billion, and security in the form of letters of credit costs from 0.5% to 3% dependent on the standing of the companies concerned, the potential cost of security could be between £150 million and £200 million a year. This is based on an assumption that around 80% of the liabilities would be with larger, investment grade companies, which are likely to pay around 0.5% for letters of credit. Upon transfer of an asset we would retain section 29 notices on all exiting companies and they would continue to carry decommissioning liabilities in their accounts. The major oil companies would certainly object to a blanket requirement to provide security where they have not previously needed to because of their financial strength.

28. The benefit of this option is that the taxpayer would have the highest possible protection from defaults (thought only marginally higher than under Option 2) but at a very high cost to the industry. Securities would often be provided by some of the largest companies in the world where the risk of default is extremely low. The regime would be easier to administer in that it would no longer be necessary to make judgements about a company’s financial standing and there would be no withdrawal of notices establishing decommissioning liabilities; on the other hand significant resources would be needed to enforce this provision across some 130 companies. We do not regard this option as providing an appropriate balance of costs and benefits.
Business sectors affected

29. The impact of all of the options considered would be confined mainly to the oil and gas sector. Some 130 companies currently have decommissioning liabilities for their interests in developed UKCS fields. These companies include major international oil companies, mid-sized independent companies, subsidiaries of other groups and smaller independents. The preferred option will impact principally on companies whose net worth is less than double their decommissioning liabilities.

30. There will be benefits to companies (both large and small) who are co-licensees with companies which have to provide security as their contingent risks under the joint and several responsibility will be reduced. There are also likely to be positive benefits for the financial sector, mostly banks, who would gain business from providing the securities required.

Equity and fairness

31. It is inevitable that the requirement to provide security will apply to companies with limited financial resources but we believe this is a necessary feature of a prudent business approach.

F. Risks

32. The total cost of decommissioning UKCS offshore infrastructure over the next 25 to 30 years is between £15 billion and £19 billion with costs for individual structures ranging from £5 million to £250 million. Companies are assessed by comparing their net worth with their decommissioning liabilities. If liabilities are more than 50% of net worth, a company may have some difficulty meeting its liabilities; if liabilities are more than 70% of net worth, the company could have considerable difficulty meeting its liabilities. Of the 133 companies currently carrying decommissioning liabilities, 29 (22%) are assessed as being in the highest risk category; in most cases the risk will be reduced by the presence of stronger partners in the licence groups and the joint and several nature of liabilities.

33. After almost 30 years of oil and gas activity the first case of companies defaulting on their obligations under the Act occurred in 2005 with the companies developing the Ardmore field. The decommissioning costs were around £5 million and considerable effort was required to ensure the costs did not fall to the taxpayer.

34. The Department has considered the lessons of the Ardmore case and concludes that the risk of such defaults will grow with the trend to smaller developments being handled by companies with limited financial resources. Experience of implementing the current legislation shows that there are cases where the decommissioning obligation cannot be put on all the parties responsible for placing an installation or pipeline in the marine environment. For instance, in some cases the obligation cannot be created at the right time, in others the business models that have evolved in the North Sea mean some parties are not within the scope of the 1998 Act as it stands. The numbers of companies concerned is small but the potential risks could be high and we believe these gaps should be closed.

35. It is important that if companies set money aside to cover their decommissioning obligations in a segregated fund over which they have no control, the whole of that fund should be available for the intended purpose if the company subsequently fails. We propose to ensure this outcome by disapplying certain provisions of insolvency legislation.
36. Extensive discussions with the industry have led us to focus on three options. These do not include a proposal brought up in PILOT by the industry for an automatic clean break from decommissioning liabilities for the sellers of licence interests if a standard security agreement is put in place. Under the PILOT proposal, the responsibility and costs for decommissioning if the company(ies) responsible defaulted would depend entirely on the effectiveness of the security agreement. If that failed in some way, the responsibility would pass to the government rather than the original builders of the installation or pipeline. The standard agreement has never been activated to cover a default situation; nor has it been tested in the courts. The effectiveness of the agreement would be heavily dependent on accurate predictions of the costs of decommissioning, which are currently not achievable given the lack of experience of such work. Although it was argued that the proposal would lead to more sales of licence interests and thus investment in the UKCS, it has not been possible to demonstrate that these benefits would outweigh the risks in transferring all the contingent liabilities to the public purse.

G. Enforcement

37. The responsibility for ensuring decommissioning obligations are met and that appropriate decommissioning security is put in place rests with BERR. This is fulfilled through the provisions of Part IV of the Petroleum Act 1998 and through Departmental guidance. Failure to comply with certain requirements of the 1998 Act can lead to criminal prosecution.

H. Recommendation

38. We recommend that:

   i) The 1998 Act be amended as proposed under Option 2 to allow the Secretary of State discretion to require decommissioning security at any time during the life of an oil or gas field if the risks to the public purse are assessed as unacceptable;

   ii) the Act be amended to provide protection for segregated decommissioning security funds from insolvency procedures;

   iii) the Act be amended to enable the Secretary of State to make all the relevant companies party to the decommissioning liabilities for an installation or pipeline.

I. Monitoring and Evaluation

39. Minister has agreed with the leading oil industry trade association, Oil & Gas UK, that the handling of decommissioning liabilities will be reviewed in 18 months time (from 30 Oct 2007). This will include consulting different sizes of companies on the impact of our security requirements. The primary objective of protecting the taxpayer from having to pay for decommissioning work will be continuously monitored as part of day to day work.

J. Specific Impact Tests

Competition assessment

40. We do not believe that the implementation of option 2 will have competition impacts. Activity on the UKCS is still dominated by major oil companies but there are increasing numbers of medium-sized independents, subsidiaries of utilities and smaller companies
entering the market and competing for opportunities to buy assets. The proposals will apply to all companies on the basis only of their financial strength relative to the related risks. The security requirements will apply equally to new and existing companies and do not relate to UK companies’ export activities. We do not believe the potential increases in the costs of security relative to the costs of oil and gas projects and the turnover of the companies concerned would be sufficient to affect the existing market structure.

Small Firm’s Impact Test

41. Whilst our proposals will have more impact on the less financially robust companies involved in the UKCS they are intended to be proportionate, relating the security requirement to the comparison of net worth and liabilities. Although we refer to small companies and some may well have fewer than 50 employees, they may well be backed by large investment trusts or venture capitalists and will be investing large sums in the development project. We do not believe that the cost of security when compared to the overall costs of oil and gas developments is an unreasonable burden. The average figures taken from 4 recent new projects were a development cost of £71 million and a decommissioning cost of £8 million; a letter of credit for that liability would cost about £900,000 a year (including fees and cash collateral costs) or 1.25% of the development costs. In the past year, 3 companies have recognised the Department’s concerns about their financial standing and have arranged security for the initial high risk start-up period of their projects.
## Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Carbon Assessment</td>
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<td>No</td>
</tr>
<tr>
<td>Other Environment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Health Impact Assessment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Race Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Disability Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Gender Equality</td>
<td>No</td>
<td>Annex A</td>
</tr>
<tr>
<td>Human Rights</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
Annex A Equality Impact Tests

Race, Disability and Gender Equality

This proposal does not impact on equality, because it applies to companies, not individuals and does not differentiate on the basis of race, gender or disability.
What is the problem under consideration? Why is government intervention necessary?
The scheme in the Energy Act 2004 for decommissioning offshore renewable energy installations does not specifically provide that decommissioning funds will be available for their purpose even if the developer becomes insolvent, nor does the Act enable the Secretary of State to require a decommissioning programme from a controlling associate of the developer when the developer does not make adequate arrangements for decommissioning. There are also limitations in the existing information gathering powers meaning that the Secretary of State may be unable to require the provision of necessary information.

What are the policy objectives and the intended effects?
The objective is to ensure that there is certainty about how our international obligations to decommission redundant offshore renewable energy installations will be met and that this will be done by the developer or his controlling associate, with minimised risk of recourse to the taxpayer, so that “the polluter pays”.

What policy options have been considered? Please justify any preferred option.
1. Do nothing
2. Introduce statutory trust insolvency protection; enable obligations to be placed on associates if not satisfied with decommissioning arrangements at any stage; and extend powers relating to acquisition of information (our proposal).
3. Introduce statutory trust insolvency protection and always put obligations on associated companies.
4. Introduce statutory trust insolvency protection and extend powers relating to acquisition of information without placing obligations on associate companies.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
Within 2 years of implementation

Ministerial Sign-off For final proposal/implementation stage Impact Assessments:
I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:
Date: 09.01.08
**Summary: Analysis & Evidence**

<table>
<thead>
<tr>
<th>Policy Option: 2</th>
<th>Description: Introduce statutory trust insolvency protection; enable obligations to be placed on associates; extend information gathering powers</th>
</tr>
</thead>
</table>

### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description and scale of key monetised costs by ‘main affected groups’</th>
<th>Costs to associated companies - but transfer rather than additional decommissioning costs - and only if the Secretary of State is not satisfied with decommissioning or financial security arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Admin costs to business estimated at £100-400k per annum.</td>
<td></td>
</tr>
<tr>
<td>Government – admin &amp; legal £50 000 (one off cost)</td>
<td></td>
</tr>
<tr>
<td><strong>One-off (Transition)</strong> Yrs £ 50k</td>
<td></td>
</tr>
<tr>
<td><strong>Average Annual Cost (excluding one-off)</strong> £ 100-400k 25</td>
<td></td>
</tr>
<tr>
<td><strong>Total Cost (PV)</strong> £1.7m – £6.6m</td>
<td></td>
</tr>
</tbody>
</table>

### ANNUAL BENEFITS

<table>
<thead>
<tr>
<th>Description and scale of key monetised benefits by ‘main affected groups’</th>
<th>The key benefit of this policy is the transfer of risk of the cost of decommissioning falling on the taxpayer, back to the companies.</th>
</tr>
</thead>
<tbody>
<tr>
<td>It is not possible to predict the benefits for the taxpayer/exchequer on an annual basis. Based on figures from the Climate Change Capital Report on Decommissioning Offshore Renewable Energy Installations commissioned by BERR in 2006 the total cost of decommissioning all consented and operating Round 1 and Round 2 windfarms could be up to £335m. Figures for decommissioning all wave and tidal devices range from £25m - £250m. An ‘average’ 240 MW Windfarm could attract decommissioning costs in the region of £8m based on decom costs of £40,000 per MW. 4-5 cases may cost the government £15m - £200m. As this is a transfer this will not be included in the Total Benefit.</td>
<td></td>
</tr>
<tr>
<td><strong>One-off</strong> £ N/A</td>
<td></td>
</tr>
<tr>
<td><strong>Average Annual Benefit (excluding one-off)</strong> £ N/A</td>
<td></td>
</tr>
<tr>
<td><strong>Total Benefit (PV)</strong> £</td>
<td></td>
</tr>
</tbody>
</table>

### Other key non-monetised costs by ‘main affected groups’

- The reduction in contingent liabilities for some companies

**Key Assumptions/Sensitivities/Risks**

We are assuming a total of around 40 offshore renewables projects by 2020, with a lifespan of about 25 years, an estimated 10% plus of which might be vulnerable to insolvency. Decommissioning costs for individual projects could vary from a few million to over £40m.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV) £ - (1.7m to 6.6m)</th>
<th>NET BENEFIT (NPV Best estimate) £ -4.9m</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>25</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

What is the geographic coverage of the policy/option? UK
On what date will the policy be implemented? 2008
Which organisation(s) will enforce the policy? BERR
What is the total annual cost of enforcement for these organisations? £ N/A
Does enforcement comply with Hampton principles? Yes/No
Will implementation go beyond minimum EU requirements? N/A
What is the value of the proposed offsetting measure per year? £ -
What is the value of changes in greenhouse gas emissions? £ -
Will the proposal have a significant impact on competition? No
Annual cost (£-£) per organisation (excluding one-off) Micro Small Medium Large £100k £400k £400k
Are any of these organisations exempt? No No N/A N/A

**Impact on Admin Burdens Baseline (2005 Prices)**

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>Net Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 50k</td>
<td>£ nil</td>
<td>£ 50k</td>
</tr>
</tbody>
</table>

**Key:**

- Annual costs and benefits: Constant Prices
- (Net) Present Value
A. Strategic Overview

1. This Impact Assessment (IA) considers the potential impact of proposals for legislative changes to the statutory decommissioning scheme for Offshore Renewable Energy Installations (OREIs). Under the Energy Act 2004, the Secretary of State can require developers of OREIs to submit and eventually carry out a decommissioning programme for their installation. The detail of the scheme is set out in guidance for business published in December 2006 and this includes decommissioning standards and financial security requirements.

B. The Issue

2. Experience of offshore decommissioning in the oil and gas sector, and of consulting on and beginning to implement the renewables decommissioning scheme, has highlighted areas where further legislative powers or safeguards are desirable to ensure that the scheme achieves its objectives. The proposals cover the protection of decommissioning funds in the event of insolvency; the ability to place decommissioning obligations on a controlling associate instead of on the developer himself (as can already be done in the oil and gas sector); and extending the information powers within the Act.

C. Objective

3. The objective is to ensure that funds are available for decommissioning even if the developer has inadequate resources but his controlling associate has sufficient resources, and even if the developer (or anyone else subject to a decommissioning liability) becomes insolvent. It is also to ensure that the Secretary of State has access to all relevant information necessary in order for him to make a judgement on the suitability of a decommissioning programme.

4. The policy will cover persons responsible for OREIs that are issued with a decommissioning notice under section 105 of the Energy Act 2004 (or otherwise made subject to a decommissioning liability), and their controlling associates. Decommissioning obligations, including the provision of financial security, will only be applied to associates where the Secretary of State has concerns that inadequate arrangements have been made to ensure a satisfactory decommissioning programme will be carried out.

Devolution

5. The offshore renewables decommissioning requirements in Part 2 of Chapter 3 of the Energy Act 2004 apply to territorial waters in or adjacent to England, Scotland and Wales (between the mean low water mark and the seaward limits of the territorial sea – i.e. GB internal and territorial waters) and to waters in the Renewable Energy Zone (including that part adjacent to Northern Ireland territorial waters, where Northern Ireland has fisheries interests). At present the decommissioning requirements do not cover Northern Ireland internal or territorial waters. The provisions on insolvency will apply to companies established in Northern Ireland as they do to those established elsewhere in the United Kingdom.
The proposal

6. The Energy Act 2004 already includes a statutory decommissioning scheme for OREIs. The proposals in the Energy Bill will not change developers’ existing obligations to submit a decommissioning programme, provide financial security and eventually decommission their installation. Their aim is to strengthen these arrangements so that:

- It is absolutely clear that funds set aside for decommissioning should only be used to meet decommissioning costs even in the event of the insolvency of a person subject to a decommissioning liability, so that they are not available to an insolvency office-holder for distribution to the general body of creditors. Our expectation is for these funds to be ring-fenced via trusts or other financial arrangements (such as secure escrow accounts) so that they will fall outside the scope of insolvency legislation. There is a precedent, in the Coal Industry Act 1994 (section 29), for exemption from the scope of the Insolvency Act 1986. We expect the safeguarded funds will be available to another developer who assumes responsibility for an installation, or to the developer’s controlling associate or, in the absence of another developer, by the Government in accordance with its international obligations.

- the Secretary of State can make a body corporate that is a controlling associate of a developer responsible for submitting and carrying out a decommissioning programme if he is not satisfied with the decommissioning arrangements (including financial arrangements) proposed by the developer. We have taken the opportunity to clarify the existing provisions in the Energy Act 2004 that controlling associate companies may also be made liable for decommissioning obligations through the decommissioning programme review process.

- decommissioning obligations will apply equally to all businesses that are bodies corporate, whatever their corporate form, whether it is a company, a limited liability partnership or another form of body corporate.

- the Secretary of State has sufficient information
  a. to be able to assess the financial viability of companies and/or their associates to carry out their decommissioning obligations; and
  b. to carry out his functions fully, fairly and transparently, thereby ensuring that the quality of decision-making is enhanced.

7. The legislative changes will be supported by modifications to the published guidance and, if required and appropriate, supported by the existing regulations.

Further information on OREIs and decommissioning costs

8. In 2001, the Crown Estate announced the grant of leases for offshore wind farm developments for “Round 1” of offshore wind-farm leasing. As of April 2007, 5 of those developments had been constructed with a generating capacity of 340 MW out of the (around) 1.3GW of capacity that has received consent in Round 1. Round 1 was a

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23 Escrow is a legal arrangement in which an asset (often but not always) money is delivered to a third party to be held in trust pending a contingency or the fulfilment of a condition or conditions in a contract such as payment of a purchase price. Upon that event occurring, the escrow agent will deliver the asset to the proper recipient, otherwise the escrow agent is bound by his or her fiduciary duty to maintain the escrow account.

“demonstration round” and the submission of an acceptable decommissioning programme was not a statutory requirement. The Crown Estate requires from Round 1 developers a decommissioning plan one year before the expiry of the lease and, for the purposes of decommissioning, a guarantor in the event of the project failing.

9. Under the “Round 2” issuing of Crown Estate leases, which ended in December 2003, 15 projects with a total generating capacity of between 5.4 and 7.2GW were offered Agreements for Lease by The Crown Estate. As of December 2007, four of these projects with a total generating capacity of 2.3GW have been consented while another 5 applications for consent are under consideration. The four Round 2 projects which have been consented have been issued with decommissioning notices under section 105 of the Energy Act 2004 under which they are required to submit a decommissioning programme prior to construction commencing. As of September 2007, two decommissioning programmes have been submitted to BERR for approval.

Rationale for Government intervention

10. The Government’s international obligations. Under the United Nations Convention on the Law of the Sea (UNCLOS), once disused or abandoned, installations are to be removed from the marine environment. Two of this convention’s aims are to ensure safety of navigation and protection of the marine environment. The Government has also ratified the Convention for the Protection of the Marine Environment of the North-East Atlantic (known as the OSPAR Convention25). If a developer should find it is unable to decommission its OREI, the Government is therefore under a duty to undertake the decommissioning (at its own expense if necessary) in order to comply with its international obligations. As a possible last resort payer and ultimate risk bearer, the Government has a duty to reduce the financial burden on the taxpayer and thus should endeavour to minimise the risk of default on decommissioning by developers.

11. Polluter Pays Principle. According to the “polluter pays” principle, polluters should pay for the pollution caused by their activity. As the OREI has to be removed at some point, the Government believes it should be the developer responsible for that installation, or the developer’s controlling associate, that should pay for its decommissioning.

12. The Government’s policy on promotion of renewables. The Government is committed to a target of 10% of electricity coming from renewable sources by 2010. The 2003 Energy White Paper recognised that a key contributor to this target would be offshore wind.26 Our proposals should help the offshore renewables sector by making it easier for developers, particularly smaller ones operating singly, by making it absolutely certain that funds will be available to meet decommissioning costs even in case of insolvency.

13. Potential for default on decommissioning. An offshore renewable energy developer has to submit a costed decommissioning programme. Research on offshore wind farms suggests that because of the potential revenue steam available for an offshore wind project and the way in which offshore wind in financed it is reasonable to expect that a the developer will be able to put forward sufficient funds to meet its decommissioning costs. However, there are several risks with non-negligible probabilities. First, developers could underestimate decommissioning costs in their decommissioning programme.

25 OSPAR is the current legislative instrument regulating international cooperation on environmental protection in the North-East Atlantic. It combines and updates the 1972 Oslo Convention on dumping waste at sea and the 1974 Paris Convention on land-based sources of marine pollution.

26 ‘Future Offshore’ calculated in 2002 that this could provide 40-50% of the target.
Second, revenues from the wind farm may not be sufficient to cover decommissioning costs due to underperformance of the technology (the wind farm may not perform as well as expected or the difficulty of the marine environment could make operation and maintenance slow and expensive). Third, offshore assets might be transferred in the future to smaller companies with less financial standing than the ones currently in the market. These risks provide reasons for requiring adequate and ring-fenced financial security - as provided for in the Energy Act 2004, and in the proposed Bill provisions.

14. The decommissioning guidance published in December 2006 set out the government’s approach to requiring financial security, including the principles that would be applied and examples of the types of financial security that would be likely to be acceptable. Given that the policy on requiring financial security has been widely consulted upon and agreed by government, it makes sense to take this opportunity to put beyond any doubt that security set up to meet decommissioning costs should only be available for that purpose in the event of a developer’s (or an associates) insolvency - precisely one of the circumstances when such a fund would be needed. Given the risks outlined above, it also follows that the ways in which companies choose to establish themselves, such as through the setting up of a Special Purpose Vehicle should not increase the risk that liabilities fall on the government and taxpayer.

Who would be affected?

15. This proposal would affect developers of OREIs and their associated companies. All projects (except those which received consent or were put into operation prior to June 2006) are required to submit a decommissioning programme to the Secretary of State in line with the principles laid out in the guidance. (Those not covered by The Energy Act 2004 scheme are required to submit decommissioning programmes to The Crown Estate.)

Consultation

16. A joint oil and gas/renewables “offshore energy decommissioning” formal public consultation took place from June - September 2007 for 12 weeks, and consultees included the renewables and oil and gas industry, business representatives, insolvency and company law specialists and those representing fishing, navigation and environmental interests.

D. Options Identified

17. The objective is to minimise the risk of default on decommissioning, whilst encouraging the development of the offshore renewable industry.

18. The Government has considered four options, which are:

Option 1: Do nothing

Option 2: Introduce statutory trust insolvency protection; enable obligations to be placed on associates if not satisfied with decommissioning arrangements at any stage; and extend provisions relating to acquisition of information (our proposal)

Option 3: Introduce statutory trust insolvency protection and always put obligations on associated companies.
Option 4: Introduce statutory trust insolvency protection and extend provisions relating to acquisition of information without placing obligations on associate companies

E. Analyse the Options

**Option 1: Do nothing**

19. The Government continues to rely on the Energy Act 2004 provisions. Under this option, the industry submits decommissioning programmes to the Secretary of State with proposed financial security arrangements which may, for example, include the accrual in a fund of security from the mid life of an installation. The developer would have had to pay for the cost of the security, to comply with the Energy Act 2004 provision but with no benefit to the government (taxpayer) in terms of funds to pay for decommissioning to meet international obligations, ensure the safety of navigation and protect the marine environment.

20. In practice, under the current arrangements – in line with the government’s published guidance – it is possible we would be unable to accept accrual funds unless a developer could demonstrate that funds would be secure in the event of insolvency. We could not rule out the possibility that an insolvency office-holder might be able to successfully challenge the purpose of such funds. Therefore, the otherwise attractive option of accruing funds from the mid life of an installation might therefore not be open to some developers and they would be required to provide potentially more costly forms of security. This would be detrimental to the government’s wish to encourage the further development of the industry. This option would also mean that the Secretary of State would be unable to impose decommissioning liabilities on an associate and gather additional information necessary for the approval of a decommissioning programme.

**Costs and Benefits**

21. The do nothing option would not add to current industry costs but the potential costs to the taxpayer will be higher than other options considered because there is a greater risk that if a developer defaults on his decommissioning obligations the government may have to pay. Under the current provisions of the Energy Act 2004, the Secretary of State does not have the power to give a decommissioning notice to an associate company when he feels that the primary developer does not have sufficient ability to meet its decommissioning obligations itself. This in effect means that the Secretary of State may have to reject some decommissioning programmes on the grounds that he is not satisfied that they have enough resource necessary to meet their obligations. The current system also has some unhelpful limitations to the information gathering provisions, which may result in the same effect, of the Secretary of State being unable to approve a decommissioning programme through a lack of relevant information.

22. The costs of financial security for some developers may rise if they cannot use a mid-life accrual fund due to the insolvency risk, i.e. the risk that funds will not be available for decommissioning as planned, in the event of a developer becoming insolvent. Developers will choose the most efficient financial security for their OREI, within the boundaries put in place by HMG.

23. The impact on companies depends on their standing with their banks and their financial strength. Companies with very limited resources may have to provide cash collateral to back a letter of credit. Oil and gas experience suggests that the direct cost of a letter of credit – not taking account of impact on borrowing would be between 0.5-3% of...
total decommissioning costs depending on the companies concerned. Smaller companies would be likely to pay higher rates of 2-3% of total decommissioning costs i.e. up to an additional total cost of £660k for a 100MW offshore wind farm assuming decommissioning costs of £4m and an incrementally increasing letter of credit over 10 years.

24. Developers might also face expensive legal costs in seeking to develop complex (and legally expensive) trust arrangements to try and demonstrate that funds will be secure in the event of insolvency. The outcome of developing such arrangements is not guaranteed to be successful in avoiding the application of the Insolvency Act 1986 and similar legislation, whereby a developer’s assets might be liable for distribution to creditors in the event of insolvency. Due to the relatively new and developing nature of the offshore renewables industry, there are currently no standard ‘off the shelf’ financial packages which financing companies have yet developed or offered to the market that we are aware of, however as the industry develops further it is likely that this situation will change.

25. The benefits to the industry of “doing nothing” are that decommissioning obligations cannot be placed on associated companies unless they are constructing, operating or using an offshore installation, or party to a proposal to do so. We would also not be extending information gathering powers so there would be less of a burden on companies through not having to provide information which the Secretary of State deemed necessary.

26. The benefits to government of doing nothing would be in resource terms: this approach would be the least resource intensive in present terms, requiring no legislative changes. It allows Government resources to be focused on other issues affecting the industry where alternatives do not exist. However, since it increases the risk that in the case of default liabilities could fall on HMG, this option is likely to take up increased resources in the longer term. The default of an oil and gas operator in 2005 has so far amounted to 450 staff days at a cost of at least £225k.

27. There is a small potential cost to the environment under this option in that default on decommissioning, should it occur, would be likely to delay decommissioning of the OREI, possibly harming the marine environment. This risk arises as we would look to exhaust all alternatives before decommissioning a site, such as transferring the licence to a new operator, unless there was a total failure of equipment which meant the site was effectively unable to continue operation.

Option 2: Introduce statutory trust insolvency protection; enable decommissioning obligations to be placed on associate companies; and extend information gathering powers

28. This is the option we are proposing. It puts beyond any doubt that security set up for the purpose of meeting decommissioning costs can only be used for that purpose in the event of the insolvency of the company with the decommissioning liability and is not available for distribution to the general body of creditors. It also enables the Secretary of State to place obligations on associated companies (such as parents) if he is not satisfied that adequate arrangements (including financial arrangements) have been made by the developer and to seek appropriate information at relevant times to enable him to carry out his functions under the decommissioning chapter of the Energy Act 2004 effectively. The proposal follows much the same approach taken for oil and gas decommissioning in respect of associated companies; and also follows the same approach as the insolvency protection proposals for oil and gas in the Energy Bill.
29. If companies are confident of the decommissioning programmes they submit and the financial projections underpinning them, the provision should provide a safety net for government whilst not being too onerous on the industry.

Costs and Benefits

30. Statutory protection of their decommissioning fund may make financial security easier and cheaper to arrange for developers and provide added security for joint ventures thus reducing risk and encouraging development of the sector.

31. The maximum cost of the proposal to make associated companies liable for decommissioning obligations if the Secretary of State is not satisfied that adequate arrangements have been made by the responsible developer is the cost of decommissioning itself, plus any financial security costs. Assuming (an unrealistic) worst case scenario for the industry where all developers defaulted leaving associated companies responsible, this would amount to a total estimated decommissioning cost of £335 million for offshore wind developers and £63-£250 million for the wave/tidal sector, using the assumptions from Climate Change Capital’s (CCC)’s report.

32. In reality, the costs would be much smaller because costs will only arise for associated companies in the event that the Secretary of State is not satisfied with the decommissioning arrangements put in place by the developer, i.e. the holder of the primary obligation. The likelihood of the industry defaulting en masse is very low. Taking account of CCC’s research and assumptions on capacity, credit ratings and the likelihood of default in relation to offshore wind, the expected default amount is estimated between £0-20 million across the industry. This is a measure of the total potential decommissioning costs weighted by the credit rating of the licensing applicants; £20 million is the expected defaulted value if all license applicants had a credit rating of CCC to C. If this default liability is passed onto associated companies of offshore wind developers, it will be a transfer of funds between the parent and the SPV/SPC, not an additional cost caused by the policy. We would also expect that the associate could take advantage of any security that had been set up so the figure could well be lower.

33. Decommissioning costs in the mid-life accrual scheme are between 0.4 and 0.7% of the total levelised cost of generating electricity from off-shore wind farms (see full RIA on the decommissioning guidance for offshore renewable energy installations). These decommissioning costs are set to fall on associated companies only when the developers themselves cannot meet their obligations in full or part. The proposal does not impose additional decommissioning costs but transfers costs from one company to its associate. We envisage that associated companies who become liable for decommissioning because a developer has become insolvent would be able to access, in stages, any funds set aside prior to default, as decommissioning is undertaken.

34. The benefits of safeguarding funds in the event of insolvency and being able to place obligations on associated companies would give certainty that funds could not be distributed to the insolvency office holder in the event of insolvency, and thus be 100% sure that the costs of decommissioning would not fall to the taxpayer. There are likely to be some costs associated with any administration of a trust or small fees relating to an

escrow account but developers would be able to choose the most attractive financial security option for them taking account of their own particular circumstances.

35. There are also likely to be costs on parents/associated companies relating to accounting provisions, for instance because this creates a potential contingent liability which they will need to account for; the closer monitoring of their associates (if they are not doing so already); and on companies in relation to legal advice to explain the proposals and handle any issues that may arise. These will vary depending on the day rates, how many additional days work are required and on the complexities of particular cases. Based on rough estimates of the additional accountancy and legal advice that a business may need in order to understand the proposals and their particular circumstances, and to make and monitor the appropriate accounting provisions, the additional administrative costs on business might be expected to be in the region of £100-£400k per annum (plus VAT) across the industry. However, as indicated previously, the risk and associated cost of liabilities falling on HMG is likely to be lower than under any of the other options.

Option 3: Introduce statutory trust insolvency protection; and always put obligations on associated companies

36. This option is similar to option 2 above but enables the Secretary of State to put decommissioning obligations – including financial security requirements - on associated companies (as well as the original companies) as a matter of course. It would minimise the risk of liabilities falling on HMG. However, it would impose an unnecessary added burden on the offshore renewable energy industry and take the renewables regime beyond the associated company requirements for oil and gas decommissioning. We are seeking to bring the renewables regime in line with the oil and gas regime in this regard, rather than to go beyond it.

Costs and Benefits

37. This is the highest cost option to industry. As for option 2, it provides statutory safeguards for funds set aside for decommissioning. It places decommissioning options on associated companies in addition to financial security requirements which developers are required to make, even if there are no concerns about the ability of the developer to meet its decommissioning obligations. It provides additional protection to government thus reducing significantly the risk of decommissioning costs falling to HMG. However, it effectively involves the industry putting forward a second tier of security irrespective of whether the initial tier of security offered is sufficient or not. This is incompatible with our objective to encourage the development of the sector. This option would not impose an extra burden on industry with regard to the information gathering requirements which are not included in this option, however this would also mean that the Secretary of State may not have access to all the relevant information he deems necessary in order to judge the suitability of a decommissioning plan.

Option 4: Introduce statutory trust insolvency protection and extend information gathering powers without placing obligations on associate companies

38. This option allows wind farm developers to propose mid life accrual funds which they can categorically demonstrate will be secure in the event of insolvency. It means

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29 Escrow is a legal arrangement in which an asset (often but not always) money is delivered to a third party to be held in trust pending a contingency or the fulfilment of a condition or conditions in a contract such as payment of a purchase price. Upon that event occurring, the escrow agent will deliver the asset to the proper recipient; otherwise the escrow agent is bound by his or her fiduciary duty to maintain the escrow account.
developers are responsible for their decommissioning obligations but these obligations cannot initially be imposed on associated companies (unless they are party to the proposal to construct, operate or use a wind farm under the existing provisions of the Energy Act 2004).

39. The downside of this approach is that it increases the risks of decommissioning liabilities falling on the taxpayer if companies default and have no assets the Secretary of State could recover, either because the financial security has not begun to accrue or it has not accrued sufficiently (e.g. because the fund has not been completed or costs are greater than estimated.)

Costs and Benefits

40. This is likely to be the least cost option for the offshore renewable industry. It has the benefit of enabling the industry to establish a cost-effective accrual fund which they can demonstrate will categorically be secure in the event of insolvency, whilst imposing no additional burdens on the industry. It sends a positive signal that we are keen to overcome issues to make it easier for developers to provide financial security, consistent with our wish not to impose a higher cost than necessary on the offshore renewable industry. There would also be an additional slight cost burden to industry relating to the proposed powers of information gathering.

41. The risk of liabilities falling on the public purse is higher than under our proposed option. A further potential cost is the resource cost in implementing the proposal through consultation and legislative change with no significant reduction in risk of liabilities falling to HMG. The industry may prefer resources to be focused on more imminent issues which are hindering the development of the sector.

F. Risks

42. In Climate Change Capital’s 2006 report the total magnitude of decommissioning costs was valued at up to £585 million (£335 million for all Round 1 and Round 2 offshore wind liabilities and up to £250 million for marine technologies). CCC used a range of company credit ratings as a proxy to estimate the probability of default and based on the proposed mid-life accrual decommissioning fund\(^30\), the risk adjusted exposure for this total liability was estimated at between £0-20 million in present value terms, up to 2020. The expected risk of default is built upon a range of companies’ credit ratings: if all companies involved in OREIs were credit rating C then the expected cost would be £20 million. Alternatively, if all companies were credit rating AAA then the expected cost would be £0 million. CCC and the industry recognised the estimated decommissioning costs of £40k/MW for offshore wind and £25-100k/MW for wave and tidal devices on which the analysis was undertaken were rough estimates which could change substantially once experience in OREI decommissioning were gained. The total potential liability on government would therefore increase as costs increased and/or if further capacity were built.

43. Some offshore renewable energy projects are being set up by Special Purpose Companies (SPCs) or Special Purpose Vehicles (SPVs). These are companies created for a single, well defined purpose and with the intention of seeking outside investors to

\(^{30}\) A mid-life accrual fund, where a developer would only commence putting money aside from the mid-life point of a developments operational life, is a scheme designed to account for the fact that the technology is most likely to be guaranteed during the first 3-5 years of operation, and so the risk of default is partially mitigated during the first half of the life of the plant. In addition, delaying payments into the decommissioning fund would reduce the burden on the developer, especially in the event that debt needs to be serviced for the first 10-15 years of operation.
assume a significant proportion of the risk. Of 15 Round 2 projects, 7 are believed to have set up special companies for taking forward their specific wind farm projects. The risk of default of SPV is likely to be higher than for parent companies, although the SPV may have a higher credit rating, particularly once a wind farm is operational as it is likely, especially in the case of project financed SPV’s, that the revenue stream from the project will have to stay within the SPV, thereby giving it a potentially higher credit rating than the parent. Credit reports from credit agency, Dun & Bradstreet demonstrate that 2 of the 3 consented Round 2 projects involve SPCs/SPVs, which have been issued with a decommissioning notice, and are currently assessed as having a higher risk of business failure than their owners. 75% (6 out of 8) of Round 2 projects which have been consented, or whose applications are under consideration, are currently rated by Dun and Bradstreet as having a “greater than average” risk of business failure. Whilst good business practice would suggest that some parents might cover the liabilities of their SPCs/SPVs in the event of default, there is no obligation for them to do so, unless the parents or associated companies are themselves subject to a decommissioning notice by virtue of being party to a proposal to construct, operate, use or extend an OREI. Indeed, one of the rationales for creating SPCs/SPVs may be to limit liabilities. However, SPCs/SPVs are often required by lenders to protect their revenues and enable them to match the risk and returns of their loans, rather than expose themselves to the risks associated with the parent. Such vehicles can therefore allow for the efficient allocation of capital.

Risks under Current Situation and Proposed Policy Compared

44. The current situation with regard to decommissioning policy arguably encourages developers to set up SPCs/SPVs which would bear the decommissioning liabilities (whilst recognising that there are other reasons for setting up SPCs/SPVs as highlighted above). Given that SPCs/SPVs may have a lower credit rating than their corporate parent or associated company, the risk adjusted exposure is more likely to move towards the upper end of Climate Change Capital’s (CCC’s) estimated £0-20 million range. The use of SPCs/SPVs may result in a greater number of applicants with a lower credit rating. The expected value of the decommissioning default is currently unknown within the £0-20 million range identified by CCC, but let us assume it is in the order of £15 million.

45. Under the proposed policy in which the Secretary of State will be able to approach parent firms if decommissioning funds are inadequate, the parent will have less incentive to allow their subsidiaries to fall behind or renge on decommissioning payments. Therefore, this influences the behaviour of companies with respect to default risk which will tend to reduce the overall expected default value. The value of the expected decommissioning default under the proposed policy is now lower as a result, perhaps in the region of £10 million. The end points of the distribution remains £0-£20 million as the CCC calculated range still applies - although if all firms were credit rated C without parents or associates being responsible, the range of the government’s risk-adjusted exposure would change to about £17-20 million. The proposed change of policy makes default at the top end of the scale less likely. Effectively, the policy maintains the agreed £0-20 million risk adjusted exposure to government, whereas without the change, the chances of the government having to pay would be higher.

Experience of decommissioning OREIs

46. As no decommissioning of an OREI in the UK has taken place yet, it is difficult to evaluate how effective the current policy has been (i.e. to rely on the current statutory provisions within the Energy Act 2004 in minimising the risk and consequences of default on decommissioning). It is, however, likely that – as indicated above – in the event of
The risk of the burden falling on the tax-payer will be higher than under our proposals because of the possible vulnerability of trust funds and escrow accounts in the event of insolvency; and the practice in the industry of setting up special companies for the construction of wind farms.

47. The offshore oil and gas sector is the nearest industry with which one can compare the OREI sector. It is partly regulated by the Petroleum Act 1998, which allows the obligation for decommissioning offshore infrastructure to be placed on the companies responsible and includes protection against default on decommissioning. Under the Petroleum Act 1998, BERR can require financial securities in certain limited situations to ensure decommissioning is carried out. The Secretary of State can place the liability for decommissioning on associated companies if he is not satisfied with the decommissioning arrangements (including financial) which have been put in place by companies with a duty to carry out an approved decommissioning programme. There has been one instance of default. In 2005, the Ardmore development failed and the developers went into receivership and were unable to meet their decommissioning liabilities. Contractors separately owned some of the facilities in the field; they had a decommissioning liability for that equipment, which they met. Liability for the remaining equipment was met by an associate company of one of the developers.

G. Enforcement

48. The responsibility for ensuring decommissioning obligations are met and that appropriate decommissioning security is in place rests with the Secretary of State. The Department with overall policy responsibility in this area is BERR. The decommissioning regime is implemented through the provisions of Chapter 3 of the Energy Act 2004 (sections 105-114) and published Departmental guidance. Failure to comply with certain requirements of the Act is a criminal offence and can lead to prosecution. Before construction of an OREI begins, the Secretary of State issues a notice requiring the submission of a costed decommissioning programme. This can then be approved, rejected, or modified by the Secretary of State in accordance with the provisions in the Act. The Secretary of State is also required to review decommissioning programmes from time to time (including financial security). These reviews will seek to ensure that sufficient funds will be available to meet decommissioning liabilities. Under our proposals, if concerns existed, or a default occurred, the Secretary of State would consider whether obligations should be placed on associated companies. Independent verification of decommissioning will be required (set out in the published guidance) to ensure that decommissioning has been carried out to the appropriate standard.

H. Recommendation

49. The option we are taking forward in this Energy Bill is Option 2 (introducing statutory trust insolvency protection and associate company provisions whilst taking the opportunity to extend the information gathering provisions).

50. Option 2 reduces the risk to Government without substantially hindering the development of the offshore renewable energy sector. It facilitates developers in providing appropriate financial security to demonstrate that their decommissioning liabilities can be met.
I. Implementation

Compensatory simplification

51. The Government has contingent liabilities by virtue of international obligations. It should be borne in mind that we are introducing amendments to the existing 2004 Energy Act (that is, we are not introducing a new decommissioning scheme but extending the powers of the Secretary of State to make the current scheme more effective at minimising the risk of liabilities falling on the taxpayer in the event of default of decommissioning obligations). The government will only impose obligations on associated companies if satisfactory arrangements have not been made by developers.

52. There will be no additional process for approval of decommissioning programmes. Bringing the offshore renewable decommissioning scheme more in line with the oil and gas decommissioning regime (and vice versa) should allow us to share knowledge and streamline the assessment of programmes and appropriate financial security.

53. Statutory trust protection for decommissioning funds should simplify the existing financial security obligations on developers. The Government will amend its guidance to help the industry concerned to understand its obligations and look to provide advice on standard or model trust arrangements to facilitate the provision of effective financial security by the industry.

J. Monitoring and Evaluation

54. The Government intends to review the operation of the statutory decommissioning scheme as a whole at an appropriate future date. This could be linked to any future licensing round for offshore renewable energy installations (but will be dependent on policy decisions about any future licensing round). The review will involve consulting interested parties for their views on the implementation of the policy and on whether there have been any unintended consequences. Proposed and accepted financial security provisions will also be reviewed, to assess whether estimated decommissioning costs are likely to be sufficiently well covered.

K. Specific Impact Tests

Small Firms Impact Test

55. Our proposal are intended to be proportionate, relating the security requirement to the comparison of net worth and liabilities. To the best of our knowledge, there are few small firms (i.e. firms that employ less than 250 people full time) that act as developers in the offshore wind farm sector at the moment. However, some firms set up SPVs or SPCs to take forward particular wind farm projects, most of which have significantly fewer than 250 full time employees and some have none.

56. There are around fifty firms in the UK involved in the development of wave/tidal devices. This industry comprises small and large companies

57. Impact on small firms in the wave/tidal sector: The proposal is not thought to have a disproportionate effect on small firms. The ability to categorically demonstrate that funds are secure in the event of insolvency may, in particular, benefit small firms who may not have the resources to enter into other financial security arrangements.
Distribution Impacts

58. The policy to make associated companies liable in the event of default will have an impact on companies in the following ways:

Company A – Can pay its own decommissioning liabilities. In this instance the policy will have no impact, as the Secretary of State will not require the associate company to pay as the company can cover its own decommissioning liabilities. This is the case if this company is an SPV or a stand-alone company.

Company B – Cannot pay its decommissioning liabilities; does not have an associate company. The proposed policy would not have an impact on this company because there is no associate company for the Secretary of State to require to cover its liabilities. HMG will be required to pay the remaining decommissioning costs in line with the status quo.

Company C – Cannot pay its decommissioning liabilities; has an associate company. This is the only scenario in which the proposed policy will have an impact; the Secretary of State will have the power to ensure that the associate company covers the decommissioning liabilities of its defaulting company. This will result in the associate having contingent liability, which is an inevitable consequence of the ‘Polluter Pays’ principle.

59. Our proposal will only have an impact on Company C’s associate as it increases the associates’ liabilities. However, these companies are likely to be larger and better capitalised, hence more able to absorb this risk than firms without parents, for example. The effect of the policy will be to encourage “parent” companies to behave in a less risky manner than otherwise as they will have to meet any default costs arising from their investments.

60. If the Secretary of State is able to collect decommissioning funds from the parent it will mean there is a reallocation of costs between HMG and industry. Where available, a parent will be required to cover the decommissioning liabilities of its subsidiary as opposed to the cost being borne by HMG.

Competition Assessment

61. The offshore wind energy industry is characterised by several large vertically integrated utility companies, a number of oil and gas companies seeking to diversify and several niche market players who specialise in renewable energy. It is a multinational industry with participation by a number of European-based energy companies. The sector is a dynamic one and has seen a number of recent acquisitions and mergers.

62. In the wave and tidal industry there are 50-odd companies actively developing the technology, which is not yet commercial. The wave and tidal sector is less developed than the offshore wind industry.

63. In the offshore wind industry developers tend to form consortiums when the size of the project is several hundreds of MW or more. Thus, for Round 1, (where the average size of projects is relatively small at below 100MW) the development of projects has tended to be undertaken by a single company. For Round 2, the size of projects averages several hundreds of MW and, possibly to minimise risks and costs, many but not all projects are being developed by a consortium of developers.
64. The proposed changes would apply only to developers that are subject to the Energy Act 2004 scheme as set out in the BERR guidance on the scheme, i.e. it will not apply to those that had not received consent for their projects before June 2006, which is presently around 20 companies who are taking forward projects either individually or in consortia.

65. The cost of the proposal is not thought to affect disproportionately the sector covered by the proposed policy as it represents a small proportion of total costs borne by developers. The proposal is not thought to lead to significantly higher set-up and ongoing costs for new developers. Finally, it is not considered likely that the proposal will change the current market structure.
## Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
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</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
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<td>No</td>
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<tr>
<td>Legal Aid</td>
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<td>Health Impact Assessment</td>
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<tr>
<td>Race Equality</td>
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<td>Annex A</td>
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<tr>
<td>Disability Equality</td>
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<tr>
<td>Gender Equality</td>
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<td>Annex A</td>
</tr>
<tr>
<td>Human Rights</td>
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<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
Annex A Equality Impact Tests

Race, Disability and Gender Equality

This proposal does not impact on equality, because it applies to companies, not individuals and does not differentiate on the basis of race, gender or disability.
What is the problem under consideration? Why is government intervention necessary?
The current legislative framework has shortcomings that may become more apparent as the commercial environment changes. For example, the increased risks to the taxpayer posed by a greater number of smaller companies mean that it is important that the regulator has the ability to take swift and decisive action (for example, to withdraw part of a licence) or have greater confidence in up to date licensee information (by sharing information from HRMC).

What are the policy objectives and the intended effects?
The overarching policy objective is to maximise economic recovery of oil and gas. A key part of this is to ensure a fair, competitive market supported by an effective and efficient regulatory framework.
Also it is important that there is compliance with the regulatory framework to ensure a level playing field in the market.

What policy options have been considered? Please justify any preferred option.
The proposals put forward are small housekeeping changes responding to the changed market circumstances. The proposals enable the Department to:

Item 1 – partially revoke an interest in a petroleum licence providing additional licensing flexibility;
Item 2 – ensure abandoned wells are not left ‘suspended’ (i.e. capped temporarily) indefinitely; and,
Item 3 – address the unconsented transfers of licence interests.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
The policy should be reviewed in 2010.

Ministerial Sign-off For final proposal/implementation stage Impact Assessments:

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Date: 09.01.08
**Summary: Analysis & Evidence**

**Policy Option:** Oil and Gas Licensing Proposals

**Description:**

Description and scale of key monetised costs by 'main affected groups'. Costs would be incurred only under item 2 (abandoned wells). They would be incurred by the licensees responsible for suspended wells.

### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description</th>
<th>Yrs</th>
<th>Cost Range (£)</th>
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<tr>
<td>One-off (Transition)</td>
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</tr>
<tr>
<td>Average Annual Cost</td>
<td>15</td>
<td>£16k – 23k</td>
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</table>

Total Cost (PV): £188k – 279k

Other key non-monetised costs by 'main affected groups' Costs of additional administration by the companies concerned or BERR are likely to be minimal since work associated with the policy measures is not anticipated to require additional resources.

### ANNUAL BENEFITS

<table>
<thead>
<tr>
<th>Description</th>
<th>Yrs</th>
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<tr>
<td>One-off</td>
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<tr>
<td>Average Annual Benefit</td>
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<td>£0.35m</td>
</tr>
</tbody>
</table>

Total Benefit (PV): £4.1 million

Other key non-monetised benefits by 'main affected groups' These proposals give those businesses involved and the regulator greater legal clarity and therefore the confidence to invest for the long term. Saved time of regulator staff.

**Key Assumptions/Sensitivities/Risks**

Events’ addressed by these proposals will be very rare, so frequency and impact are both difficult to predict. The central assumptions are an oil price of $60 per barrel (pb); production costs of $20pb, exchange rate of $2=£1 and real discount rate of 3.5%. We have assumed a small field (producing 2,000 barrels per day over 5 years) with one occurrence of a partial revocation of a licence resulting in a 1 year deferment of production every 10 years and deferment of production for a year owing to collapse of a licence consortium with an unconsented partner once every 20 years.

**Price Base Year:** 2007  
**Time Period Years:** 15  
**Net Benefit Range (NPV):** £3.8 – 3.9m  
**NET BENEFIT (NPV Best estimate):** £3.85m

**What is the geographic coverage of the policy/option?**  
UK

**On what date will the policy be implemented?**  
October 2008

**Which organisation(s) will enforce the policy?**  
BERR

**What is the total annual cost of enforcement for these organisations?**  
£ minimal

**Does enforcement comply with Hampton principles?**  
Yes

**Will implementation go beyond minimum EU requirements?**  
N/A

**What is the value of the proposed offsetting measure per year?**  
£ 0

**What is the value of changes in greenhouse gas emissions?**  
£ 0

**Will the proposal have a significant impact on competition?**  
No

**Annual cost (£-£) per organisation (excluding one-off):**  
<table>
<thead>
<tr>
<th>Micro</th>
<th>Small</th>
<th>Medium</th>
<th>Large</th>
</tr>
</thead>
<tbody>
<tr>
<td>No</td>
<td>No</td>
<td>No</td>
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</table>

**Are any of these organisations exempt?**  
No

**Impact on Admin Burdens Baseline (2005 Prices)**

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>£</th>
<th>Net Impact</th>
<th>£</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimal</td>
<td></td>
<td></td>
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</table>

**Key:**  
Annual costs and benefits: Constant Prices  
(Net) Present Value
A. The Issue

1. The background is that of the changing commercial environment of the North Sea as demonstrated by, for example: more smaller players taking an increasing number of licence interests; smaller finds; rising exploration and production costs and the growing need to ensure fair access. In short, the commercial environment is changing.

2. There are 4 proposed changes to the current oil and gas licensing regime involving the Department’s ability:

- to partially revoke a petroleum licence;
- to ensure abandoned wells are not left ‘suspended’ indefinitely;
- to deal with unconsented transfers of licence interests.

Partial revocation of licences

3. The North Sea now has a far wider range of players including a number of smaller companies; most licences have a number of parties that operate under a ‘Joint Operating Agreement’ for exploration and production. When one of the parties on the licence is involved in insolvency, a change of ownership, or a breach in residence requirement (i.e. where it no longer has a UK base) currently the Department can only revoke the licence interests of all the persons on the licence. This removes the licence interest from all parties rather than just the one ‘defaulting’ party. This can therefore act against the national interest when it may be better for the ‘non-defaulting’ licensees to remain on the licence and carry out the agreed work programme without disruption rather than withdrawing the licence and offering it in the next licensing round at a later date.

4. The proposal seeks to change this and provides for a power to partially revoke the licence interest of the ‘defaulting’ licensee whilst retaining the legal interest of the other parties. There may be advantages in the remaining licensees continuing to carry out work under the licence, both economically (since petroleum production generates revenues) and from an environmental perspective – for example, revoking an entire licence might cause practical problems for ensuring that there are no oil or gas leaks. In practice, the Secretary of State would expect to consult the non-defaulting parties before exercising this power of partial revocation.

Costs/benefits

5. Firstly, this proposal will reduce the administrative burden in the system that would arise if the remaining licensees were obliged to have to re-apply for a licence.

6. The main benefit derives from the ability to avoid the effective deferral of oil/gas production from the time the licence would have been revoked in full to when production recommences under the remaining/new licensees – a period of typically a year. There is also the risk that, in the case of marginally economic fields, production would not recommence at all. The benefit would accrue to the remaining parties on the licence and the Exchequer. There are no additional costs on business from this proposal. It would not have any impacts on competition, and will improve the situation for those smaller firms that are active explorers and developers on the UKCS.
7. In terms of estimates of benefit, the typical daily production of a small field with a partner in default might be in the region of 2,000 barrels (0.73m barrels pa) with a field life of 5 years. If we assume that a partial revocation is necessary once every 10 years and there is a deferment of production/revenue for a year then there is a NPV benefit over 15 years of £2.8m, assuming an oil price of $60 per barrel (pb), costs of $20pb, and an exchange rate of $2=£1; the average annual benefit in this case is £0.23 million. The NPV benefit rises to £4.8m if the oil price is $90pb, and falls to £0.7m if the oil price is $30pb. Similarly (with oil price of $60pb) if the event is once every 5 years then the NPV benefit rises to £5.5m.

Abandonment of wells

8. Oil and gas is extracted from the ground through a well which penetrates the earth’s surface so as to release the hydrocarbons. Wells may also be used for purposes of exploration and appraisal i.e. to see whether hydrocarbons are present. At present the licensee is required to meet the following conditions:

- a well must be plugged when it is abandoned permanently;
- any conditions as set out in the Minister’s written consent to the well being abandoned must be complied with;
- the plugging of the well must meet specifications, and;
- the well must be plugged and abandoned not less than one month before the end of the licensee’s licence.

9. In practice, wells are often “suspended” for a period of time before being finally abandoned. Abandoning and plugging a well is a costly exercise. Given that the interval between suspension and final abandonment of the well may be a number of years, there is a risk that licensees will not continue to be able to finance the final plugging of the well when the time comes, particularly given the market is no longer only made up of large multinationals. Government intervention is necessary to ensure that wells are properly plugged when abandoned and the taxpayer is protected from funding the action.

10. The proposal is two-fold. First, to give the Minister a new power in the terms of licences to direct that licensees plug and seal wells from which petroleum has not been extracted for at least 28 days at any time during the term of the licence. This will ensure licensees plug and seal wells in a timely manner, if the Government decides it is in the taxpayer’s best interests. Second, allowing the Minister to take action – including taking financial security from a licensee – in circumstances where it appears that the licensee will not be capable of plugging the well properly when the time comes. At present the Minister has a similar power, but this only applies to wells forming part of an offshore installation, not to exploratory or appraisal wells.

11. There is benefit to the taxpayer since the likelihood of the cost of plugging an abandoned well falling on them would decrease. The licensee is required to plug the abandoned well in the near future rather than at some point in the future when there is a possibility, albeit small, that the licensee will be unable to do so. This does mean that there is an additional cost to the licensee in bringing the cost of plugging the well forward in time, aside from the lack of choice and flexibility on the part of the licensee over the timing of such work. This will either be in the form of the Minister directing action or requiring financial security for the costs that the licensee is liable for. This proposal will support competition by helping to ensure a level playing field as all actors in the market will be subject to the cost of plugging the wells they abandon. This proposal does not add
new burdens to small businesses although it is inevitable that the fewer wells a licensee is required to plug and seal, the more that the costs associated with each well will impact on the company’s overall financial position. There will also be less scope for smaller players to benefit from ‘economies of scale’ from the costs of plugging and sealing several wells at a similar time or using the same contract/equipment. There is minimal administrative impact from this proposal: any work would be covered under existing resources.

12. In terms of estimates of costs, the typical cost of plugging and sealing an individual well is assumed to be, and to remain, about £1m ($2m). Assuming this cost is brought forward by an average of 5 years (the average length of time a suspended well remains suspended) and the likelihood of this event occurring is once every 10 years, the NPV over 15 years of the cost is £188k (3.5% discount rate); the average annual cost in this case is £16k. To a smaller player, the true cost is probably that of an opportunity cost – the scope to use funds in other ways that are required to fund the work now rather than later. In the event that the SoS requires the licensee to put in place funding for plugging and sealing the well when the time comes (on the consideration that there is sufficient uncertainty that the licensee will be unable to fund the work at that stage) the estimated cost for a Letter of Credit or similar is 5% of the required funds pa – for 5 years an additional sum amounting to an NPV over 15 years of £279k; the average annual cost in this case is £23k.

13. In terms of benefit to the taxpayer, this would arise from the loss of risk of having to pick up the bill to plug and seal the well in the event that the licensee lacks the necessary financial resources to do so at the appropriate time. If the bill is £1m (as above), discount rate 3.5%, and the frequency once in 10 years, then over a 15 year timeframe the NPV of this risk is £1.04m

Unconsented Licence Transfers

14. The licence to explore and bore oil and gas is a contract between the Minister and the licensee. At present, if the licensee wants to transfer the licence to another player in the market the Minister has to be informed and give prior consent. This ensures that licensees are suitable persons; for example, that they will do their best to efficiently maximise the UK’s petroleum resources. This also allows the Minister to regulate the market effectively and allows subsequent transfers of licences to take place.

15. The problem is that in certain cases transfers have occurred without the Minister giving consent or having any knowledge of the transfer. Where an unconsented transfer has occurred there could be situations where the transferee is not efficiently maximising the petroleum resources of the UKCS. Therefore government intervention is needed to provide legal clarity on the required legal process and to enable the Minister to regulate effectively.

16. There are three changes that would work together to resolve the problem. The first is to give the Minister power to direct that a licence interest revert back to the transferor where a transfer has been made without the Minister’s prior written consent. For example, the Department could use its powers in circumstances where the transferee is not considered suitable to act as a licensee (e.g. they may have a track record of not making efficient use of the UK’s petroleum resources). This power is likely to encourage companies to be particularly careful to seek permission before transferring interests to another party, since otherwise the Department has the ability to transfer the interest back to the original party. Transferees will be able to make representations to the Minister to ensure all information is considered before the interest is transferred back.
17. The second area of this proposal is a provision for an information gateway between HMRC and BERR so that specific information collected by HMRC in connection with petroleum revenue tax on the transfer of licence interests, may be provided to BERR. This will alert the Department to those transfers made without the necessary consent. The provision will provide limited data only to enable the BERR to carry out its regulatory duties.

18. The third area of this proposal is to give the Minister a power to require a licensee who has transferred their interests in a licence without the Minister’s consent to submit an abandonment programme. This provision is necessary as there are circumstances in which companies that have not obtained Ministerial consent to transfer their licence interests may not be caught by the decommissioning provisions.

19. Benefits occur to the taxpayer since the likelihood of the potential liabilities falling to the taxpayer decreases if licensees are fit to hold licences. Also there is the competition impact of creating a fair market with a level playing field, as only those deemed to be ‘suitable’ and who adhere to the licence can act in the market. To provide some quantitative indications of the case of the former, if there is a 5% pa year chance of a licence partnership collapsing that leads to a complete loss of production, then over a 15 year timeframe the NPV from a field producing 6000 barrels of oil equivalent per day, $60 pb, $20pb costs, $2=£1 and discount rate of 3.5%, the loss of value would be £6.6m, multiplied by the tax rate for the loss of revenue to the Exchequer (typically 50%, hence £3.3m)

20. The costs arising from this measure would apply to those not complying with the requirements of their licences – in effect the potential loss of revenue stream from their share of the licence interest. This cost will also avoid potential loss to the Exchequer, although this would be small and would only arise as a loss of tax revenue should the overall production levels by the licensed partnership fall as a direct result of the transferee being unsuitable (largely perhaps through financial collapse).

21. We estimate that a case of unconsented transfer where the Secretary of State considers there are grounds to ‘undo’ the transfer will arise perhaps once in 20 years, and the time between the defaulting party acquiring the licence interest and the licence being revoked about a year at most. This gives rise to an NPV over 15 years (assuming a field producing 2,000 barrels of oil equivalent per day over 5 years, $60 pb oil price, $20pb costs, $2=£1 and discount rate of 3.5%) of £1.4m; the average annual benefit in this case is £0.12 million. Any benefit to the ‘defaulting’ party has clearly arisen through a breach of the licence conditions and therefore a removal of that benefit is not a legitimate ‘cost’.

22. There would be a very low is no administrative burden from acting on this proposal; any actions would be met from existing resources.

Devolution

23. There are no devolution issues as oil and gas is a reserved matter under the Scotland Act 1998 and functions have not been transferred under the Government of Wales Act 1998.

B. Specific Impact Tests

Competition Assessment

24. Proposed changes will help ensure that all firms applying for licences (new applicants), or existing licence holders on the UKCS have the same obligations and do
not gain any unfair advantage over each other through their size, length of time they have held a licence, or through licence transfers without the SoS’s consent.

**Small Firms Impact Test**

25. Proposed changes will help ensure that none of the parties on the licence will, through either insolvency or an inherent inability to undertake their licence commitments, pose an unacknowledged threat to the planned work programme (via partial revocation and reversal of unconsented transfers) regardless of size of the various licence partner companies, or length of time they have held a licence, etc.

26. While it is expected that the power to require plugging and sealing of a well, or security to do so, will only be exercised rarely, it clearly will have a disproportionate effect on smaller firms simply on account of their fewer financial resources, and increased likelihood to be those from whom some form of financial security is required. However the overall licence obligations – to plug and seal wells - remains the same.
### Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
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</tr>
<tr>
<td>Other Environment</td>
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<td>No</td>
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<tr>
<td>Health Impact Assessment</td>
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<td>No</td>
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<tr>
<td>Race Equality</td>
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<tr>
<td>Disability Equality</td>
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</tr>
<tr>
<td>Human Rights</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
Annex A Equality Impact Tests

Race Equality

This proposal does not impact on race equality because it affects companies in the oil and gas sector, not individuals.

Disability Equality

This proposal does not impact on disability equality because it affects companies in the oil and gas sector, not individuals.

Gender Equality

This proposal does not impact on gender equality because it affects companies in the oil and gas sector, not individuals.
What is the problem under consideration? Why is government intervention necessary?

Businesses which own the upstream petroleum infrastructure (which includes upstream petroleum pipelines onshore and offshore, upstream gas processing facilities and upstream oil processing facilities) have a monopoly over their use and are in a position to abuse their monopoly power to charge higher access charges to third parties than is reasonable. In the current legislation there are gaps and uncertainties in the coverage of the Secretary of State’s powers to determine third party access (including determination of terms and charges) in case of disputes. This means that some parts of the upstream petroleum infrastructure are not covered. This lack of coverage could leave some of the infrastructure being inefficiently used, as disputes remain unresolved and potentially reduce the amount of recovery of oil and gas compared to the maximum economic levels. Government intervention is required to ensure Government can play a role to resolve disputes in all parts of the upstream infrastructure. Moreover, developers have said additional legal clarity would be helpful.

What are the policy objectives and the intended effects?

The overarching policy objective is to maximise economic recovery of oil and gas through the efficient use of existing infrastructure. The proposed extension and clarification of powers would restrict the monopoly power of owners, by extending the scope of the existing dispute resolution legislation to capture upstream infrastructure which currently falls outside the framework.

What policy options have been considered? Please justify any preferred option.

Without changes some of the upstream petroleum infrastructure would be left outside the regulatory framework i.e. the powers contained in the legislation which enable to Secretary of State to resolve disputes over access. The proposal put forward is to make small housekeeping changes that extend the powers that the Secretary of State presently has to the parts of the upstream petroleum infrastructure that are not presently covered (see Evidence Base for further details).

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?

It is suggested that the policy be reviewed every 3 years.
### Summary: Analysis & Evidence

<table>
<thead>
<tr>
<th>Policy Option: Third Party Access</th>
<th>Description: Extend Scope of Legislation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>COSTS</strong></td>
<td>Description and scale of key monetised costs by ‘main affected groups’</td>
</tr>
<tr>
<td><strong>ANNUAL COSTS</strong></td>
<td>There would be enforcement costs only if there are disputes requiring resolution by the Secretary of State. It is hoped that there will be no disputes requiring resolution by the Secretary of State as a result of the legislation.</td>
</tr>
<tr>
<td>One-off (Transition) Yrs</td>
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<tr>
<td><strong>£ 0</strong></td>
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<tr>
<td>Average Annual Cost (excluding one-off)</td>
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<tr>
<td><strong>£ 0</strong></td>
<td></td>
</tr>
<tr>
<td><strong>BENEFITS</strong></td>
<td>Description and scale of key monetised benefits by ‘main affected groups’</td>
</tr>
<tr>
<td><strong>ANNUAL BENEFITS</strong></td>
<td>Users should get more timely, lower cost access to infrastructure resulting in faster/greater oil and gas production. The benefit would accrue to the oil and gas companies concerned and to the Exchequer; there would also be transfers from infrastructure owners to users.</td>
</tr>
<tr>
<td>One-off</td>
<td></td>
</tr>
<tr>
<td><strong>£ 0</strong></td>
<td></td>
</tr>
<tr>
<td>Average Annual Benefit (excluding one-off)</td>
<td></td>
</tr>
<tr>
<td><strong>£ 5–20 million</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Other key non-monetised costs by ‘main affected groups’</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Other key non-monetised benefits by ‘main affected groups’</strong></td>
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</tbody>
</table>

#### Key Assumptions/Sensitivities/Risks

- **£5-20 million** is an estimate of the potential scale of annual benefit, with a central estimate of **£10 million**. The actual benefit will depend on which new fields are brought forward for development which might use the infrastructure in question, their size and prices when they are in production. Please see paragraph 9 for a more detailed explanation of the assumptions.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV)</th>
<th><strong>£ 55-230 million</strong></th>
<th><strong>£ 115 million</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>15</td>
<td></td>
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</tbody>
</table>

- **What is the geographic coverage of the policy/option?** UK
- **On what date will the policy be implemented?** October 2008
- **Which organisation(s) will enforce the policy?** BERR
- **What is the total annual cost of enforcement for these organisations?** **£ 0**
- **Does enforcement comply with Hampton principles?** Yes
- **Will implementation go beyond minimum EU requirements?** Yes
- **What is the value of the proposed offsetting measure per year?** **£ 0**
- **What is the value of changes in greenhouse gas emissions?** **£ 0**
- **Will the proposal have a significant impact on competition?** No

<table>
<thead>
<tr>
<th>Annual cost (£-£) per organisation (excluding one-off)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Micro 0</td>
</tr>
<tr>
<td>Small 0</td>
</tr>
<tr>
<td>Medium 0</td>
</tr>
<tr>
<td>Large 0</td>
</tr>
</tbody>
</table>

- **Are any of these organisations exempt?** No

<table>
<thead>
<tr>
<th>Impact on Admin Burdens Baseline (2005 Prices)</th>
<th>(Increase - Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase of £</td>
<td>Decrease of £</td>
</tr>
<tr>
<td>Key: Annual costs and benefits: Constant Prices</td>
<td>(Net) Present Value</td>
</tr>
</tbody>
</table>
A. The Issue

1. Access by third parties to upstream petroleum infrastructure i.e. oil and gas pipelines, FPSOs (i.e. Floating Production, Storage and Offtake vessels), oil processing facilities and gas processing facilities - in Great Britain and the territorial sea - is achieved by negotiation between the party wanting access and the owner of the infrastructure in question, regulated by a voluntary industry Code of Practice.

2. In the event that interested parties cannot reach a satisfactory negotiated deal, the party wanting access can, except in some limited circumstances, apply to the Secretary of State to determine that access should be granted and on what terms. In the current legislation there are gaps in the coverage of the Secretary of State’s powers to determine third party access that mean some parts of the upstream petroleum infrastructure are not covered. For example a party may seek access to all links in the chain of the infrastructure, but the Secretary of State could determine a dispute over only certain parts of it. This undermines the efficacy of the access regime as a whole; this is certainly true of access to oil processing facilities and, arguably, of access to certain gas processing facilities and control services.

B. Objectives

3. To ensure that the entirety of the upstream oil and gas infrastructure is brought within the reach of the Secretary of State’s powers to resolve disputes in this area if a prospective user of such infrastructure applies to the Secretary of State to do so.

Proposal

4. Without changes some upstream petroleum infrastructure would be left outside the regulatory framework. The proposal put forward is to make small housekeeping changes that extend the powers that the Secretary of State presently has to the parts of the upstream petroleum infrastructure that presently are not, or may not be, covered.

5. These technical changes are designed to address those limited circumstances, which relate to:

(i) access to onshore oil processing facilities and pipelines, and to Floating Production and Offloading Systems,

(ii) gas processing facilities such as the Shell/ExxonMobil facilities at Mossmorran and Braefoot Bay which may at present be unintentionally excluded from the scope of the relevant legislation; and

(iii) ancillary services required for the operation of the upstream petroleum pipeline infrastructure.

6. They should have no or minimal cost implications for industry, unless and until there is an application for intervention by the Secretary of State - there has been none to date. However, at least two previous prospective applications have been frustrated because of the restricted scope of the current legislation. Part of the benefit of having these elements fully covered by the regime will be to deter owners of the upstream infrastructure to which the dispute resolution powers would be extended from using their monopoly power to offer terms for access to their infrastructure which are significantly in excess of
a cost-reflective level. If there were to be an application for resolution of an access dispute to infrastructure/services not previously covered by the legislation then there would be some (relatively trivial) costs for the owners, most notably in providing information to the Secretary of State, and, in the case of gas processing facilities, publishing main commercial conditions for access. Equally, there would be minor costs for the Secretary of State in assessing the case. The Department expects that owners would factor these costs into their decisions on the terms that they would offer to prospective users since both parties would prefer access to be obtained through negotiation.

7. The benefits are enabling greater recovery of oil and gas, by effectively using the infrastructure that may previously have been avoided by users due to monopolistic pricing. There are minor competitiveness benefits by enabling the third party access to the market, and benefits to smaller firms if they are a third party that challenges successfully under the new legislation - the scale of those benefits would depend on the difference between the terms that were available from negotiation and the terms determined by the Secretary of State.

**Average Annual Benefit**

8. Users should get more timely, lower cost access to infrastructure resulting in faster/greater oil and gas production. The benefit would accrue to the oil and gas businesses concerned and to the Exchequer; there would also be transfers from infrastructure owners to users (these have not been quantified as they would be transfer payments).

9. The range of estimates of £5–20 million pa around a central estimate of £10 million pa (all in 2007 prices) derives from the following. If we assume that one development per year, with extra production of 3 million barrels for each of 5 years, benefits from the proposed change, then there is an NPV benefit of £9.5 million from bringing that production forward a year (assuming an oil price of $60/barrel, production costs of $20/barrel and exchange rate of $2:£1). If one development benefits only every second year the NPV benefit falls to around £5 million. If the typical beneficiary field has total production of 30 million barrels instead of 15 million barrels the NPV benefit would double to around £20 million. These are all indicative but, we believe, reasonable figures which give ballpark estimates. There are around 20 new field developments a year, some with higher/longer production profiles than those assumed, so the potential benefit is greater than indicated if more or even bigger fields benefit.

**Devolution**

10. No devolution issues are expected to arise as a result of these proposals as oil and gas is a reserved matter under the Scotland Act 1998.

**Enforcement costs**

11. It is hoped that the extension and clarification of the scope of the dispute resolution legislation will not result in any (more) disputes being referred to the Secretary of State. At present, some disputes cannot be determined by the Secretary of State because e.g. oil processing facilities are outside the scope of the legislation. While it is possible that such disputes could in future be referred to the Secretary of State it is hoped that, instead, the increased threat of referral from the fuller scope of the legislation will mean that infrastructure owners are more likely to offer acceptable terms to prospective users and to do so in a timely fashion. If, nevertheless, a dispute is referred, the enforcement costs would be low, involving a few existing staff for a small part of a year.
Industry Consultation

12. Industry representatives have been notified in advance of the proposed changes via correspondence and through meetings with industry groups.

EU requirements

13. Existing legislation on dispute resolution in relation to access to oil and gas pipelines and onshore gas processing facilities has already been amended to implement the Gas Directive. There is no similar EU requirement relating to resolution of disputes over access by third parties to oil processing facilities so, to that extent, the proposed legislation goes beyond minimum EU requirements. The current legislation is, however, not implementing an EU requirement.

C. Specific Impact Tests

Competition Assessment

14. Although it is intended to influence substantially the price that suppliers (i.e. affected infrastructure owners) would otherwise offer by limiting the extent of their monopoly power, the proposal would not directly limit the number or range of suppliers. Nor would it indirectly limit the number or range of suppliers, limit the ability of suppliers to compete or reduce suppliers' incentives to compete vigorously.

Small Firms Impact Test

15. Few if any of the infrastructure owners affected by the proposal are small firms. Even if their full-time employment in the UK were below 50, to own North Sea oil and gas infrastructure they must be substantial economic entities.

European Convention on Human Rights (ECHR).

16. It is considered that the proposals are fully legitimate and proportionate within the meaning of the appropriate Articles and Protocols of the European Convention on Human Rights (ECHR).
## Specific Impact Tests: Checklist

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Annex A – Equality Impact Tests

Race Equality

This proposal does not impact on race equality because it affects companies in the oil and gas sector, not individuals.

Disability Equality

This proposal does not impact on disability equality because it affects companies in the oil and gas sector, not individuals.

Gender Equality

This proposal does not impact on gender equality because it affects companies in the oil and gas sector, not individuals.
Summary: Intervention & Options

Department /Agency: Department of Business, Enterprise and Regulatory Reform
Title: Recovery of Offshore Electricity Licensing Regime Tender Costs and Transfer of Property Rights and Liabilities Scheme

Stage: Consultation Version: Final Date: 9th January 2008

Available to view or download at: http://www.berr.gov.uk/energy/sources/renewables/policy/offshore-transmission/page40532.html
Contact for enquiries: Paul Hawker Telephone: 020 7215 1125

What is the problem under consideration? Why is government intervention necessary?
The Government is currently working with the Gas and Electricity Markets Authority ("the Authority") to establish a licensing regime (offshore transmission licences) for high voltage lines (132kV and above) and associated plant and equipment which convey electricity from offshore generating devices such as wind farms to Great Britain’s electricity network. Once the regime is established, the Authority will award the licences via a competitive tendering exercise. Where the generator-developer of a wind farm has built, is building or has committed to build the transmission system for its project, the successful bidder for the licence will need to take over the transmission-related property, rights and liabilities from their current owner. The problem is that there is currently no compulsory transfer scheme if commercial negotiations fail between the current asset owner and the new transmission licence holder. The Department and the Authority are concerned this may result in unnecessary disruption or delay to offshore wind generation development, hence the proposed Government intervention. In addition, the Authority’s existing powers of cost recovery do not enable it to recover its costs from participants in running competitive tenders to identify an offshore transmission licensee. Government intervention is necessary in order to give the Authority the appropriate cost recovery mechanisms.

What are the policy objectives and the intended effects? The objective of the policy is to ensure that the Authority has the power to run tender processes for granting offshore transmission licences in an effective and efficient way. The intended effect is to enable offshore renewable electricity generation to connect to the onshore grid in an economic and efficient manner whilst maintaining the integrity of the whole system and delivering best value to consumers.

What policy options have been considered? Please justify any preferred option. The Government has considered (1) the option of proceeding without further powers for the Authority, i.e. do nothing. Its preferred option is (2) taking new legislative powers to establish mechanisms to enable Ofgem to run an efficient and effective tender process and avoid potential delay from commercial negotiations failing on transfer of property, rights and liabilities. Delays to establishing an effective transmission licensing regime would delay the further development of offshore renewable deployment. The proposed changes will also enable the Authority to recover its costs of running the tender process from participating parties.

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the desired effects?
3 years after the implementation of the regime.

Ministerial Sign-off For consultation stage Impact Assessments:
I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:

Date: 09.01.08
### Summary: Analysis & Evidence

#### Policy Option: Extend Scope of Legislation

**Description:**

The average cost for Ofgem to run a tender process is estimated at around £0.5m per project. The estimated internal OFTO bid costs are estimated at £0.25m-£1m. There would also be an estimated cost of £80k to the Competition Appeal Tribunal (CAT) of hearing one appeal against a property scheme per year. All costs are based on a 6-year period.

<table>
<thead>
<tr>
<th>COSTS</th>
<th>ANNUAL COSTS</th>
<th>Average Annual Cost</th>
<th>£5.3 – 22.3 million</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>One-off (Transition) Yrs</td>
<td>£ 0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Annual Cost (excluding one-off)</td>
<td>£5.3 – 22.3 million</td>
<td>6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Cost (PV)</td>
<td>£ 29.6m – 123.3 million</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**BENEFITS**

**ANNUAL BENEFITS**

<table>
<thead>
<tr>
<th>BENEFITS</th>
<th>Average Annual Benefit</th>
<th>£47.1 – 96.7m</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>One-off</td>
<td></td>
<td>£ 0</td>
<td></td>
</tr>
<tr>
<td>Average Annual Benefit (excluding one-off)</td>
<td>£47.1 – 96.7m</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Total Benefit (PV)</td>
<td>£ 259.6 – 530.9m</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Other key non-monetised costs by ‘main affected groups’ There would be small internal costs to the generator/developer to participate in the tender process. There would be the costs to Ofgem considering an application and making a property transfer scheme and for those parties affected by it including potential CAT appeals costs.

#### Key Assumptions/Sensitivities/Risks

For both costs and benefits we have assumed that without the provisions there would be no competitive tender process, although the provisions are not solely responsible for all the benefits and costs from competitive tendering. We have assumed 3-5 bidders per project and a possible 24 projects tendered over 6 years. For the transfer scheme we have assumed that without a transfer scheme one 200-500MW project per year would suffer a 3-month delay.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV)</th>
<th>£230 - £4407.6m</th>
<th>NET BENEFIT (NPV Best estimate)</th>
<th>£318.8m</th>
</tr>
</thead>
</table>

What is the geographic coverage of the policy/option? GB, territorial sea adjacent to GB and REZ

On what date will the policy be implemented? End of 2008

Which organisation(s) will enforce the policy? BERR/Ofgem/CAT

What is the total annual cost of enforcement for these organisations? £80,000

Does enforcement comply with Hampton principles? Yes

Will implementation go beyond minimum EU requirements? N/A

What is the value of the proposed offsetting measure per year? £ N/A

What is the value of changes in greenhouse gas emissions? £ N/A

Will the proposal have a significant impact on competition? Improves Competition

Annual cost (£-£) per organisation (excluding one-off) Micro 0 Small 0 Medium 0 Large 0

Are any of these organisations exempt? No No No No

Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of £</th>
<th>Decrease of £</th>
<th>Net Impact £</th>
<th>0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Key: Annual costs and benefits: Constant Prices (Net) Present Value</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
A. Strategic Overview

1. The Government is developing a regulatory regime for offshore electricity transmission to connect large scale offshore renewable generation projects to the onshore electricity network. At the core of this work is the policy objective of achieving a 60% reduction in carbon emissions by 2050, of which the development of renewable generation represents a key part. Under the proposed regime the Gas and Electricity Markets Authority (the “Authority”, of which the executive and policy-making arm is the Office of Gas and Electricity Markets (“Ofgem”)) would undertake tender exercises to award Offshore Transmission Owner (OFTO) licences. The licence would authorise the financing, building and maintaining of the connection and associated plant and equipment (transmission assets) through which the electricity generated offshore is conveyed. The combination of the offshore generating station and the transmission assets are described in this document as the “offshore project”. Such a licensing system offshore will bring similar benefits to the existing onshore licensing such as common standards, fair transmission charges, and consumer protection. The tender exercises will be governed by regulations made by the Authority, and approved by the Secretary of State, under section 6C of the Electricity Act 1989 to be inserted upon commencement of section 92 of the Energy Act 2004 anticipated to be at the end of 2008.

RECOVERY OF OFFSHORE ELECTRICITY LICENSING REGIME COSTS

2. The policy objective is to ensure that the Authority is able to use alternative cost recovery mechanisms from those which currently exist to cover its costs in running the tender process and ensure commitment to the tender process from different parties. We do not consider that the existing cost recovery mechanisms are appropriate for meeting this objective since they are limited to (i) licence application fees and (ii) licence fees charged to existing licence holders. These mechanisms will not necessarily enable the Authority to recover its costs from the persons who will cause the costs to be incurred.

B. The Issue

3. BERR and Ofgem have already undertaken a number of consultation rounds on the scope and operation of the offshore transmission regime. We have concluded from these consultations that the Authority is the most appropriate body to run the tender process. In the July 2007 consultation we highlighted the need for the Authority to cover its costs when running tenders, but have not yet consulted on the detailed mechanisms for recovering the costs incurred by the Authority in doing so (which will be set out in Regulations made by virtue of the new powers in the Bill). We have therefore set out in the following paragraphs benefits and costs based on one possible implementation of the powers we will be taking in the Energy Bill.

4. BERR and Ofgem wish to enable the Authority to have alternative cost recovery mechanisms for costs incurred in respect of offshore transmission tenders. We believe it is important that Ofgem are able to ensure that those who participate in the tender process provide some form of financial commitment to it. This may be required to discourage speculative participation and therefore reduce delay, reduce the risk of increased costs and ultimately reduce the risk of the tender process not being completed (for example, if a bidder withdraws at a late stage).
C. Objective

5. In summary, we are seeking powers to:

i. enable the Authority to recover its costs of running each tender exercise from the participants in the tender exercise and request payments in respect of those tender costs during each tender exercise (and therefore prior to the OFTO being identified) from any person who participates in the competitive tender for award of an OFTO licence;

ii. enable the Authority to request payments and other forms of financial commitment from the person who has applied for or has the benefit of connection to the onshore transmission system (in most cases the generator-developer);

iii. enable the Authority to request amounts from those potentially interested in participating in a tender exercise to cover certain costs incurred by the Authority before any tender exercise is commenced; and

iv. require the asset owner to pay costs incurred by the Authority in assessing the value of the assets transferred or to be transferred for a project.

D. Risk

6. There would be a greater risk that the generator-developer and/or bidders may withdraw from the tender process if the Authority does not have the powers to put in place mechanisms to ensure financial commitment to the process. Withdrawal of bidders and/or the generator-developer would require starting a new tender process with added delay and costs. The requirement for financial commitments from these persons would help mitigate this risk as the generator-developer and/or bidders would have to factor them into any consideration of the merits of withdrawing.

Example of how costs might be recovered

7. When reading the sections on benefits and costs, please note that the powers would be implemented in Regulations made by the Authority which are still subject to consultation. The method of implementation, including the level and basis for any refund, is also subject to consultation and may therefore ultimately lead to increased or reduced benefits and costs.

8. It is currently envisaged that the powers might be implemented on the basis that participants would provide financial commitments to cover Ofgem’s total costs at each stage of the tender process and they would be liable for the costs they cause Ofgem to incur. For the generator-developer this would involve an upfront commitment to cover Ofgem’s estimated projected tender costs for each stage of the tender process. The level of this commitment would increase as the process developed and Ofgem’s workload and subsequently its costs rose. There would be a separate payment to provide cash flow for Ofgem in preparing an Expression of Interest. If a generator caused the tender process to fail then Ofgem would recover its full costs from the payment(s) made by the generator and refund any residue. If a generator complied with the tender process then it would receive a refund of its payments minus any costs it had caused Ofgem to incur.

9. For bidders this would mean a payment when responding to an Expression of Interest notice followed by payments at the beginning of subsequent stages to cover Ofgem’s costs for that stage. As with the generator, should a bidder cause the process to fail then Ofgem would recover its full costs from that participant’s payment(s). If a bidder
complied with the tender process then it would have its payment(s) refunded minus any costs which Ofgem has incurred in considering its bid. As the process progressed payments would become greater to reflect the extra work involved.

**Average Annual Benefits**

10. The main benefit of the proposed cost recovery mechanisms is that they will enable Ofgem to run the tender process in an efficient and effective way. We have measured the benefits against not having competitive tenders as proposed, while recognising that the cost recovery powers are not solely responsible for the benefits which would accrue from competitive tenders. This would mean a price regulated approach which would remove the benefits of competition and add significantly to Ofgem’s (and ultimately the consumer’s) costs as Ofgem would have to review and adjust price controls on a regular basis.

11. We have assumed that competitive tenders would bring an efficiency gain of between 10-20%. This equates to the National Audit Office analysis from 2001 and 2002\(^1\) on average efficiency gain in projects tendered under the Private Finance Initiative. This gives a potential saving of £12m-£24m per project on transmission assets worth £120m per project (this is the estimated investment required to connect existing Rounds 1 & 2 offshore wind projects). Assuming a maximum of 24 projects (under Rounds 1 and 2) may be put out for tender and that these are spread over 6 years from the establishment of the regime. This gives a total benefit of £252m-£504m for the 6 year period which gives an average efficiency gain of £42m-£84m per annum. Table 1 shows the potential benefits from running competitive tenders:

**TABLE 1**

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of projects</th>
<th>Total transmission asset value (c£105m/project)</th>
<th>Potential efficiency gains of a competitive tender process (10%-20%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008/9</td>
<td>4</td>
<td>£420m</td>
<td>£42m – £84m</td>
</tr>
<tr>
<td>2009/10</td>
<td>4</td>
<td>£420m</td>
<td>£42m-£84m</td>
</tr>
<tr>
<td>2010/11</td>
<td>4</td>
<td>£420m</td>
<td>£42m – £84m</td>
</tr>
<tr>
<td>2011/12</td>
<td>4</td>
<td>£420m</td>
<td>£42m-£84m</td>
</tr>
<tr>
<td>2012/13</td>
<td>4</td>
<td>£420m</td>
<td>£42m – £84m</td>
</tr>
<tr>
<td>2013/14</td>
<td>4</td>
<td>£420m</td>
<td>£42m-£84m</td>
</tr>
<tr>
<td>Total</td>
<td>24</td>
<td>£2520m</td>
<td>£252m– £504m</td>
</tr>
</tbody>
</table>

**Average Annual Cost**

12. In running the tender process there will be costs to Ofgem (comprising standing tender costs and tender assessment costs) which will be recoverable from tender participants. We have also included the internal bid costs to OFTOs although we recognise (as with the potential benefits of cost recovery) that the cost recovery provisions would not be solely responsible for all the costs which would be incurred as a result of holding competitive tenders. OFTO internal bid costs are based on 3-5 bidders incurring costs of between £0.25m - £1m per bid per project. £1m has been estimated to be the maximum costs and the final costs are likely to be lower as a result of an effective

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and efficient tender process. It is estimated that the majority of costs will be at the ITT stage and it is envisaged that not all bidders will proceed to this stage. Ofgem will make assessments of the tender bids. Ofgem costs include standing running costs for a core team of c. £0.4m / year irrespective of number of tenders that are issued and tender assessment costs which include specialist technical, financial and legal costs as well as Ofgem case team costs. Ofgem’s costs are likely to reduce as experience of running the tender process increases and average out at c. £0.5m / project over 24 projects. The costs may also be less for transitional projects as bidders will not be bidding to build the assets. Ofgem costs in 2008/09 are also likely to be lower as they will not be for a full year and will likely only cover the lower cost early stages of tenders. These figures include the costs for the assessment of the revenue stream. Over a 6 year period the total estimated costs would be £37.7m-133.7m. Table 2 outlines the potential costs of the tender process:

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Projects per bidder</th>
<th>OFTO internal bid costs for 3-5 bidders</th>
<th>Ofgem tender costs</th>
<th>Total possible costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008/9</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£1.8m</td>
<td>£4.8m-£21.8m</td>
</tr>
<tr>
<td>2009/10</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£2.8m</td>
<td>£5.8m-£22.8m</td>
</tr>
<tr>
<td>2010/11</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£2.8m</td>
<td>£5.8m-22.8m</td>
</tr>
<tr>
<td>2011/12</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£2.1m</td>
<td>£5.1m-£22.1m</td>
</tr>
<tr>
<td>2012/13</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£2.1m</td>
<td>£5.1m-£22.1m</td>
</tr>
<tr>
<td>2013/14</td>
<td>4</td>
<td>£3m-£20m</td>
<td>£2.1m</td>
<td>£5.1m-£22.1m</td>
</tr>
<tr>
<td>Total</td>
<td>24</td>
<td>£24m£120m</td>
<td>£13.7m</td>
<td>£31.7m-£133.7m</td>
</tr>
</tbody>
</table>

13. There may also be an opportunity cost to those involved in the tender process as a result of Ofgem requiring to hold sufficient funds to cover the costs of running the tender process from each bidder. However, it is not currently possible to state what this is likely to be as we do not know how much will be required and returned and at what stages. There would also be some additional internal costs to the generator in participating in the tender process. These would mainly be to provide information for the tender process. However, as much of this information would already have been required for the connection application process the extra costs would be small.

**Monitoring & Evaluation**

14. The policy will be monitored by BERR and the Authority. The Authority will be running the tender process and it, along with BERR, will monitor and evaluate its effectiveness to ensure that OFTOs are appointed in a proper and timely manner and that all costs incurred by the Authority are fair and reasonable.

**E. Specific Impact Tests**

**Competition Assessment**

15. We believe the proposals would improve competition in the market. The Authority’s market knowledge and independence and the lower likelihood of other parties withdrawing would give potential bidders confidence in the tender process. If used, payment and financial commitment requirements would add to the costs of participation in tenders and therefore act as additional, though justifiable, barriers to entry in order to ensure bidders are committed and not participating on a speculative basis.
Small Firms Impact Test

16. We are not aware of any small firm who would be interested in bidding alone to be an OFTO. The sector directly affected is made up almost entirely of large businesses. However, we consider that the recovery of costs by the Authority would not place a disproportionate burden on any small firms genuinely interested in bidding. The deposits will reflect the Authority’s genuine costs in running a tender and are refundable to bidders, in certain circumstances.

Carbon Assessment

17. By helping to ensure a more efficient and timely connection of offshore power the proposals would quicken the substitution of generation plant with high levels of high carbon forms of generation with renewable sources of generation. Figures are provided under the Average Annual Benefits section.

Human Rights

18. We consider that the proposals would be fully legitimate, necessary, and proportionate within the meaning of the appropriate Protocols/Articles of the European Convention on Human Rights.

TRANSFER OF PROPERTY RIGHTS SCHEME

19. Some of the earliest projects to be tendered are projects where the generator-developer has funded and built the transmission assets, has funded and is part way through building the assets, or will be ready to construct the assets (in that all necessary finance is available to enable it to do so) by the time the regime comes into force. These are known as transitional projects.

20. Under the proposed new licensing regime, transmission-related property, rights and liabilities will be transferred from the asset owner (in most cases the generator-developer) to the OFTO. Although in the majority of cases we expect the transfer of these assets and liabilities to be agreed via commercial negotiations between the parties, we believe we need a mechanism to cover the possibility of such negotiations failing to ensure that property is transferred in a fair and effective way. The transfer of property must also be achieved in a timely manner because on a particular date, currently expected to be at the end of 2009, the prohibition against unlicensed participation in the transmission of electricity will extend to transmission on high voltage lines offshore (those of a nominal voltage of 132kV or more). On that date, any offshore transmission assets (whether new or existing) will need to be regulated under an OFTO licence and a generator-developer who has not transferred relevant property rights and liabilities to the licensed OFTO will be “stranded”, since the generator-developer will not be authorised to convey its electricity lawfully to the onshore network.

B. The Issue

21. BERR and Ofgem have already undertaken a number of consultation rounds since 2005 on the scope and operation of the offshore transmission regime. We have concluded from these consultations that the Authority is the most appropriate body to run the tender process and that we need specific arrangements to cover transitional projects. In the July 2007 consultation we highlighted the need for appropriate arrangements to ensure transmission assets could be transferred for projects which fall under the transitional arrangements.
22. Under existing legislation we could face the prospect of project delays as a consequence of relying upon commercial negotiations to deliver effective transfer of property, rights and liabilities. Without a compulsory power to transfer property in situations where agreement could not be reached, this might ultimately require a further tender to find an alternative OFTO. Such delays would have an adverse impact on costs for the energy system and the start of renewable generation.

C. Objective

23. We are seeking an extension to existing legislation to provide for a statutory transfer scheme to provide a mechanism for compulsory transfer of property, rights and liabilities between parties based on the determination of terms by the Authority. This would be used if parties were not able to reach commercial agreement on the transfer in a timely way.

D. Risk

24. The risk that the asset owner and winning OFTO are unable to reach agreement on the transfer of property is small as there will normally be commercial drivers to conclude an agreement. The asset owner (normally the generator-developer) will not want to keep property that it can’t utilise and the OFTO will wish to start carrying out its new function. However, if we do nothing there is more scope for negotiations to be lengthy, particularly if one party has a vested interest in the negotiations failing. The establishment of a compulsory property transfer scheme will provide a means for either the asset owner or relevant OFTO to avoid unreasonably prolonged negotiations and knowledge of its existence may also help the two parties reach agreement sooner.

25. It is perhaps more likely that negotiations could be impeded by the need to involve third parties, for example contractors who have given guarantees for their work and whose consent would be required for the transfer of that guarantee. There is a risk, particularly where there is a large number of such third parties, that negotiations could be hampered because third parties fail to engage or act reasonably in the negotiations.

Average Annual Benefits

26. The average annual benefit of our proposal is the costs of the delays that would be avoided by securing an effective transfer scheme. We have estimated that without the proposed extension of legislation to provide for a statutory transfer scheme one offshore renewable generation project per year would be delayed by 3 months. From society’s perspective, this is assumed to bring benefits in terms of the avoided fuel costs for alternative Combined Cycle Gas Turbine (CCGT) generation, and the associated CO₂e (carbon dioxide equivalent) savings.

27. To quantify these potential benefits we have assumed that a typical offshore wind project is around 200-500MegaWatts (MW) which generates at its rated capacity for approximately 30 per cent of the time.

The costs of fuel for alternative CCGT generation

28. A 3 month delay to the development of 200-500MW of offshore wind will mean costs to society of £3.93m - £9.84m in terms of additional gas burn if alternative CCGT generation is required to meet the same amount of electricity demand based on:
• An offshore wind farm’s variable cost of generation is zero
• The principle alternative is a CCGT power station whose variable costs are the gas consumed.
• The extra cost of CCGT generation is approximately £30/MWh given a year-ahead gas price of £0.50 / therm (November 2007) and thermal efficiency of around 50% as well as a deduction of some £3/MWh for wind power’s additional system balancing costs.

29. This estimate is calculated by taking the three month average output from an offshore wind farm (i.e. 131-328 GWh) and multiplying by the extra cost of CCGT generation (£30/MWh).

\[ \text{CO}_2 \text{e savings} \]

30. Every 1 MWh of renewable generation is assumed to displace 1 MWh of CCGT generation which would otherwise produce 0.35 tCO2/MWh). Consequently, an extra 131-328 GWh of renewable generation during this three month period would result in savings to society of around 46-115kt CO2e (carbon dioxide equivalent). Based on a shadow price of carbon of £25 per tonne in 2007 which increases by 2% every year thereafter, this equates to a monetary loss of roughly £1.15 – £2.87m per annum at today’s prices in the coming years.

The value of lost income to the generator-developer of a 3 month project delay

31. The value of lost income is estimated to be £12.5m-£31.4m per project over the 3 month period based upon the following electricity prices for a renewable generator:
• Year ahead (April 2008 – March 2009) electricity price of £51.7/MWh
• Renewables Obligation Certificate (ROC) “value” assumed to be around £44 per ROC (i.e. MWh). This value is determined by the sum of the current buy-out price (£34.30) and assumed return from buy-out fund (~£10 in 2006).
• This suggests that an offshore renewable electricity generator will (at the moment) receive an income of electricity plus ROC prices of £95.70/MWh.

32. This is calculated by taking the three month output from an offshore wind farm and (131-328 GWh) and multiplying by the income received (£95.70/MWh). However, this sum is not a loss to society as a whole because a CCGT generator (by assumption) would then produce the same volume of electricity and because ROC process would adjust to reflect this shortfall in renewable generation such that the incomes of existing renewable generators would be higher. In other words, this “loss” is only a distributional impact on the generator in question. This amount has therefore not been included in the Annual Benefits section of the summary sheet.

Average Annual Costs

33. If used, the transfer property rights scheme would add costs for the parties and any affected third parties, but it would also save the costs incurred if protracted commercial negotiation were to occur in the absence of the scheme. We have assumed these costs to be similar. The Authority would also incur costs, recoverable from parties, in establishing and running the scheme. If the Authority’s transfer scheme is appealed to the CAT, costs to the parties and any third parties would increase. These costs would vary for the participants from case to case. CAT estimates that its costs would be around £80,000 per
case and these have been factored in to the annual costs of the proposals on the basis of one appeal per year. CAT would be able to absorb these costs provided the number of appeals was as low as expected.

Monitoring & Evaluation

34. The policy will be monitored by BERR and the Authority. The Authority will be responsible for running any transfer scheme and it, along with BERR, will monitor and evaluate its effectiveness to ensure that assets are transferred in a fair, proper and timely manner.

E. Specific Impact Tests

Competition Assessment

35. We believe the proposals will improve competition in the market. The establishment of a compulsory transfer scheme will provide reassurance to potential bidders and investors that the tender process will reach a timely, effective and enduring conclusion. This should encourage more potential bidders to participate in the tender process.

Small Firms Impact Test

36. The Small Business Service were consulted prior to consultation in 2005 on the whole offshore transmission regime and agreed that it was unlikely to have a significant impact on small firms as the sectors directly affected are made up almost entirely of large businesses. Those small firms in the supply chain may be adversely affected by any delay in negotiations on transfer of property between the generator and winning OFTO, which the compulsory transfer of property scheme aims to avoid. Any small firms which hold property rights affected by the property transfer scheme, eg warranties, would have the benefit of an accessible, fair and transparent appeal procedure to protect their rights if required.

Carbon Assessment

37. By helping to ensure a more efficient and timely connection of offshore power the proposals will quicken the substitution of high carbon forms of generation with renewable sources of generation. Figures are provided under the “Average Annual Benefits section.

Human Rights

38. These provisions may engage Article 1 of the First Protocol to the European Convention on Human Rights (“ECHR”) (protection of property). However, the provisions pursue a legitimate aim and are proportionate to the achievement of that aim. The provisions may also involve a determination of a person’s civil rights and obligations and therefore engage Article 6(1) of the ECHR, which protects the right to a fair and public hearing within a reasonable time by an independent and impartial tribunal established by law. The Department considers that the opportunities to make representations and the remedies available will provide an adequate safeguard of the rights which may arise under Article 6(1). Finally, the Authority will have a power to obtain information to assist it in considering an application for a scheme, which may engage Article 8 of the ECHR (privacy). However, the Authority needs to be in possession of all relevant facts before making decisions concerning property, rights and liabilities which belong to others. This information power is therefore justified under the terms of Article 8(2) as being in the interests of protecting the rights and freedoms of others.
### Specific Impact Tests: Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base?</th>
<th>Results annexed?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td>No</td>
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<td>Sustainable Development</td>
<td>No</td>
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<td>Carbon Assessment</td>
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<td>Race Equality</td>
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<td>No</td>
</tr>
<tr>
<td>Disability Equality</td>
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<td>Gender Equality</td>
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<td>Human Rights</td>
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<tr>
<td>Rural Proofing</td>
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</table>
Annex A – Equality Impact Tests

**Race Equality**

The proposals affect all parties the same regardless of race.

**Disability Equality**

The proposals would have the same effect on all parties regardless of disabilities.

**Gender Equality**

The proposals affect all parties the same irrespective of gender.
4. Smart Meters

The consultation “Energy billing and metering: changing customer behaviour” closed in October 2007 and the Government has since undertaken a wide range of analysis and impact assessment work to fully understand the costs and benefits of smart metering. The Government response to this consultation was published in April 2008.

The proposed clauses which have been introduced to the Energy Bill contain an enabling power which puts in place the necessary legal powers to enable a roll out of smart meters via modified licence conditions.

It is important to note therefore that the enabling power in the clauses only has effect when used. As such the impact assessments presented here do not assess the power itself, but a number of options for its potential use. Before using the power to roll out smart meters, a final impact assessment would be done on the proposals.

We believe there is a positive business case for a roll out of advanced metering to medium businesses and have already announced, in the 2008 budget to proceed with this; it is our intention to use this power, in the first instance, to facilitate this roll out. The business case for a roll out to small businesses and the domestic sector needs further development before final decisions can be taken regarding our policy towards these two sectors. For this reason two impact assessments accompany these clauses:

1) Medium sized businesses

The October 2007 consultation provided an impact assessment on several things, including the provision of smart meters to medium sized business (in this context a ‘medium business’ is a business within meter profile class 5, 6, 7 or 8 and/or gas consumption of less than 2,196,000 kWh and more than 732,000 kWh). This extract from that impact assessment demonstrates a positive case for a roll out to these businesses and broad support for the Government’s policy proposals.

On the basis of the impact assessment and responses to the 2007 consultation we will undertake a short final consultation on the potential licence modifications to roll out smart metering to medium sized businesses a final impact assessment will be completed at this point when the final detail of the roll out has become clear. This will also deal with the commencement date for the policy. This consultation will take place as soon as possible.

2) Small businesses and domestic consumers

This is a consultation impact assessment, giving an initial cost-benefit analysis of the potential for a roll out of smart meters to small businesses and to domestic consumers. It analyses a range of potential options and further work will now be undertaken to refine this analysis and to explore in detail some of the issues raised. This work will be undertaken in discussion with stakeholders.

Powers to amend gas and electricity distribution and supply licences to require licence holders to install, or facilitate the installation of, smart meters to small businesses and domestic consumers will not be exercised until the completion of this work and final decisions. Further impact assessment(s) will be published as appropriate.
# Summary: Analysis & Evidence

## Policy Option:
Description: Provision of Smart Meters for Business

### ANNUAL COSTS

<table>
<thead>
<tr>
<th>One-off (Transition)</th>
<th>Yrs</th>
<th>Cost (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>£ 0.8m</td>
</tr>
</tbody>
</table>

**Average Annual Cost (excluding one-off)**

<table>
<thead>
<tr>
<th>Cost (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 6.1m</td>
</tr>
</tbody>
</table>

**Total Cost (PV) £ 170m**

**Other key non-monetised costs by 'main affected groups'**

### ANNUAL BENEFITS

<table>
<thead>
<tr>
<th>One-off</th>
<th>Yrs</th>
<th>Benefit (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

**Average Annual Benefit (excluding one-off)**

<table>
<thead>
<tr>
<th>Benefit (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 43.5m</td>
</tr>
</tbody>
</table>

**Total Benefit (PV) £ 1090m**

**Other key non-monetised benefits by 'main affected groups'**

### Key Assumptions/Sensitivities/Risks

Costs annuitised using lifespan of asset and 10% cost of capital. Behavioural responses (central case) 2.5% reduction in consumption, persisting for 15 years from installation. Effectively 99% of market dominated by large companies. Net of CRC overlap.

### Price Base

| Year 2005 | Cost £ 470m - 1465m | £ 915m |

### Time Period

| Years 25 | GB Coverage | Subject to consultation |

### Net Benefit Range (NPV)

| Net Benefit Range (NPV) | £ 470m - 1465m | £ 915m |

### NET BENEFIT (NPV Best estimate)

| NET BENEFIT (NPV Best estimate) | £ 915m |

### What is the geographic coverage of the policy/option?

GB Coverage

### On what date will the policy be implemented?

Subject to consultation

### Which organisation(s) will enforce the policy?

Orgem

### What is the total annual cost of enforcement for these organisations?

£ TBC

### Does enforcement comply with Hampton principles?


### Will implementation go beyond minimum EU requirements?

£ TBC

### What is the value of the proposed offsetting measure per year?

£ 150m

### What is the value of changes in greenhouse gas emissions?

£ 150m

### Will the proposal have a significant impact on competition?

No

### Annual cost (£-£) per organisation (excluding one-off)

<table>
<thead>
<tr>
<th>Micro TBC</th>
<th>Small TBC</th>
<th>Medium TBC</th>
<th>Large TBC</th>
</tr>
</thead>
<tbody>
<tr>
<td>No</td>
<td>No</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

### Are any of these organisations exempt?

No

### Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of £</th>
<th>Decrease of £</th>
<th>Net Impact £</th>
</tr>
</thead>
</table>

---
3. Provision of Smart Meters for Business

Introduction

Ensuring businesses have direct access to information about their energy use will enable them to manage that use more effectively and reduce their carbon emissions. The Government believes that the benefits that Smart Metering brings can help businesses reduce their energy consumption.

The Government proposes that energy suppliers should extend to all but the smallest business users in Great Britain and those larger businesses not already subject to half hourly metering, advanced and smart metering services within the next five years.

Description of Policy and Rationale for Government Intervention

This measure would see Smart Meters provided to all but the smallest business users over five years from 2008. The meters would apply to both electricity and gas use. Smart Meters offer the opportunity to provide business with direct, continuous feedback on how much electricity they use and how much it costs by transmitting this information to a display device easily accessible by the business, for example through a portable display, TV or computer link. The aim of this measure is to enable business to make better decisions on their energy use and raise awareness of the costs of their actions.

Assumptions

The assumptions used in this analysis are based on the Carbon Trust Advanced Metering Field Trials, details of which can be obtained from www.carbontrust.org.uk. These trialled the use of Smart Meters in the business sector, beginning in 2004, to better understand the potential for more efficient energy use in this sector, the potential carbon savings involved and the barriers which exist to the broader uptake of this technology. The Trials suggested that Smart Metering would be cost effective for firms with profile class 5 electricity meters and above and for non-daily read gas meters with consumption greater than 732MWh p.a.
The results from these trials, in terms of potential levels of energy reduction and costs, have formed the basis for the assumptions in this CBA.

Detailed Assumptions

- It is assumed that Smart Meters, together with the provision of data, will lead to a reduction in energy consumption of between 2.8 per cent (electricity) and 4.5 per cent (gas) per meter in the central case. This is in line with the changes observed in the Carbon Trust Trials. Sensitivities around the behavioural response have also been undertaken, and are detailed below.

- Smart Meters are rolled out to those businesses that do not have half hourly electricity metering or daily read gas metering, but excluding business electricity customers with profile class 3 and 4 meters and those gas customers whose consumption is less than 73.2MWh per year. This will cover approximately 200,000 meters.

- Energy consumption information for the different profile classes is taken from Elexon and Carbon Trust data for 2006-7. This forms the basis of the future path of energy used in the analysis. But the projected profile of use has been adjusted to take account of past trends of energy use in this sector, particularly energy efficiency measures that could be expected to apply going forward. This has been based on business as usual calculations produced in cooperation with Defra, based on NERA consultancy work.

- The persistence of consumption reductions have been modelled at 15 years in the central case with sensitivity around these of 10 and 20 years.

- The Carbon Trust trial information included high and low costs of Smart Meters and on installation and maintenance. These have been used in our analysis, with the central assumption being the mid-point between these.

- Smart Meters will reduce supplier costs in several respects – for example through avoided manual reads, lower disconnection charges, reduced losses and reduced contact centre time. These have been taken into account in the analysis.
Carbon savings from this measure are based on assuming the marginal generating technology (CCGT) is displaced for the electricity savings. Assumptions on the Social Cost of Carbon and the discount rate are in line with Defra assumptions and HMT Green Book guidance.

Assumptions have been combined to give the biggest range of costs and benefits – so that the low energy reduction scenario is associated with high supplier costs and vice-versa.

Overlaps with other policy measures

There are several measures aimed at Business that aim to address more efficient use of energy in this sector. Key among these are the Carbon Reduction Commitment (CRC) and the European Energy Performance of Buildings Directive (EPBD). There will be overlaps between these measures, and the CBA presents figures gross and net of these overlaps.
\section*{CBA Results}

(i) Smart Meters for Business Sector – gross of other policy measures

<table>
<thead>
<tr>
<th>Estimate</th>
<th>Central</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon saved per annum (MtCe) in 2020</td>
<td>0.27</td>
<td>0.11</td>
<td>0.32</td>
</tr>
<tr>
<td>Total net benefit (£m present value over lifetime)</td>
<td>-1520</td>
<td>-840</td>
<td>-2230</td>
</tr>
<tr>
<td>Cost-effectiveness (£/tCe saved)</td>
<td>-350</td>
<td>-340</td>
<td>-470</td>
</tr>
<tr>
<td>Distribution of net benefit (£m present value over lifetime)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exchequer</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Firms</td>
<td>-185</td>
<td>-40</td>
<td>-255</td>
</tr>
<tr>
<td>Consumers</td>
<td>-1055</td>
<td>-645</td>
<td>-1550</td>
</tr>
</tbody>
</table>

Note: Benefit (-) Cost (+)

(ii) Smart Meters for Business sector – net of other policy measures

<table>
<thead>
<tr>
<th>Estimate</th>
<th>Central</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon saved per annum (MtCe) in 2020</td>
<td>0.14</td>
<td>0.06</td>
<td>0.17</td>
</tr>
<tr>
<td>Total net benefit (£m present value over lifetime)</td>
<td>-915</td>
<td>-470</td>
<td>-1465</td>
</tr>
<tr>
<td>Cost-effectiveness (£/tCe saved)</td>
<td>-350</td>
<td>-340</td>
<td>-470</td>
</tr>
<tr>
<td>Distribution of net benefit (£m present value over lifetime)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exchequer</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Firms</td>
<td>-185</td>
<td>-40</td>
<td>-255</td>
</tr>
<tr>
<td>Consumers</td>
<td>-580</td>
<td>-350</td>
<td>-950</td>
</tr>
</tbody>
</table>

Note: Benefit (-) Cost (+)

Whereas in the previous two policies, a distinction has been made between the wholesale price and the retail price paid by consumers, the assumption is that the price used here is the retail price paid by business. There is less difference between business retail and wholesale prices than the residential retail and wholesale prices."
What is the problem under consideration? Why is government intervention necessary?
The lack of accurate, timely information on energy consumption may prevent consumers from taking
informed decisions on energy usage to reduce consumption and thereby bills and carbon emissions.
Smart meters will provide accurate and timely data on energy consumption to consumers and
suppliers enabling informed decisions on energy use. Currently, suppliers are only likely to roll-out
smart meters to 20-30% of the market where a commercial case exists. With Government intervention,
smart meters can be extended to the rest of the market capturing the benefits of increased energy
efficiency, improved customer experience, energy network benefits and the ability to respond to future
energy market and policy developments.

What are the policy objectives and the intended effects?
The overall objective of government intervention is to provide consumers with better information on
energy usage to encourage energy efficiency and to reduce carbon emissions. The policy is also
intended to fulfil the Government’s obligations on the provision of energy information under the EU
Energy Services Directive, in particular, Article 13 which requires Government to ensure that
customers have access to a range of improved energy consumption and billing information.

What policy options have been considered? Please justify any preferred option.
This policy focuses on the potential replacement of 46 million gas and electricity meters and a range of
policy options have been considered. The main variants in the policy options proposed are:
- Option 1: No domestic smart metering policy but better billing and displays policy
- Options 2a-d: Mandated rollout of smart meters in existing metering market structures with varying
  technology levels and varying roll out timescales; and
- Option 3: Mandated rollout of high specification smart meters with a regional franchise market model.
- Small Businesses: initial assessment of implications of smart metering for small businesses

When will the policy be reviewed to establish the actual costs and benefits and the achievement of the
desired effects? In the event of a roll out of smart metering for small businesses and/or domestic
consumers, the regulator would monitor the roll out process. The policy would be reviewed once the rollout
of smart meters had been completed and a medium term review undertaken within 5 years of roll out start.

Ministerial Sign-off For consultation stage Impact Assessments:
I have read the Impact Assessment and I am satisfied that, given the available
evidence, it represents a reasonable view of the likely costs, benefits and impact of
the leading options.

Signed by the responsible Minister:
## Summary: Analysis & Evidence

<table>
<thead>
<tr>
<th>Policy Option: 1</th>
<th>Description: No domestic smart metering mandate but a better billing and displays policy</th>
</tr>
</thead>
</table>

### ANNUAL COSTS

| Description and scale of key monetised costs by 'main affected groups' |
| Description: Transition costs are made up of real time displays and their installation on request for two years (2008-2009) and for new and replacement meters over a 20 year period (from 2010). These costs are annuitised over the life time of the display (7 years), and begin when a display is installed. The annual costs are made up of the maintenance costs and the energy use of the displays. |

#### One-off (Transition) Yrs

<table>
<thead>
<tr>
<th>Description:</th>
<th>£ 1.2bn</th>
</tr>
</thead>
</table>

#### Average Annual Cost (excluding one-off)

| Description and scale of key monetised costs by 'main affected groups' |
| Description: | £ 3m |

#### Total Cost (PV) £ 0.8bn

### ANNUAL BENEFITS

| Description and scale of key monetised benefits by 'main affected groups' |
| Description: Benefits made up of electricity bill reductions and carbon benefits |

#### One-off Yrs

| Description: | £ 0 |

#### Average Annual Benefit (excluding one-off)

| Description and scale of key monetised benefits by 'main affected groups' |
| Description: | £ 89m |

#### Total Benefit (PV) £ 0.6bn – 1.9bn

### Key Assumptions/Sensitivities/Risks

- Energy savings depend on consumers' behavioural response to the display; we have made a best estimate considering the current evidence. Changes in the energy savings have a big effect on the benefits.

### Price Base Year
- 2007

### Time Period Years
- 22

### Net Benefit Range (NPV)
- £ -0.13bn to 1.1bn

### NET BENEFIT (NPV Best estimate)
- £ 0.5bn (positive)

- **What is the geographic coverage of the policy/option?** GB
- **On what date will the policy be implemented?** To be determined
- **Which organisation(s) will enforce the policy?** Ofgem
- **What is the total annual cost of enforcement for these organisations?** £ N/A
- **Does enforcement comply with Hampton principles?** N/A
- **Will implementation go beyond minimum EU requirements?** No
- **What is the value of the proposed offsetting measure per year?** £ 0
- **What is the value of changes in greenhouse gas emissions?** £ 60m - 277m
- **Will the proposal have a significant impact on competition?** No

### Annual cost (£-£) per organisation (excluding one-off)

| Description: |
| Micro | Small | Medium | Large |
| N/A | n/a | n/a | n/a |

### Are any of these organisations exempt?

| Description: |
| no | N/A | N/A | N/A |

### Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of</th>
<th>£</th>
<th>Decrease of</th>
<th>£ 25m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Impact</td>
<td>£ -25m</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Key:** Annual costs and benefits: Constant Prices (Net) Present Value
### Summary: Analysis & Evidence

**Policy Option:** 2a  
**Description:** Mandated 10-year roll out of Automated Meter Management specification smart meters within existing market structures

#### ANNUAL COSTS

| Description and scale of key monetised costs by ‘main affected groups’ | Transition costs are made up of the asset costs of the meters (£5.4bn), their installation (£2.9bn), communications costs (‘Hybrid 2’) (£2.5bn) and IT costs. Rollout is expected to begin in 2010 and reduces to new and replacement in 2018, transition costs linked to the meters begin when a meter is installed and these costs are annuitised over the life time of the meter. Legal and IT costs are annuitised over the period. Transition costs include an optimism bias to account for potential risks and optimistic cost estimates. Annual costs are made up of maintainence costs, energy use by the equipment and expected pavement reading inefficiencies (£1.1bn). |
|---|
| **One-off (Transition)** | **Yrs** | **£** |
|  |  | 16.1bn |

**Average Annual Cost**  
(excluding one-off)  
**£ 0.2bn**

**Total Cost (PV)**  
**£ 13.4bn**

#### ANNUAL BENEFITS

| Description and scale of key monetised benefits by ‘main affected groups’ | Benefits are made up of reduced energy consumption (£3.1bn), avoided peak consumption, carbon benefits, and a range of additional benefits/ cost savings to suppliers and the industry, including avoided meter reading (£3bn), customer service savings, lower working costs for prepayment meters, improved debt management, reduced theft and savings for microgen users. |
|---|
| **One-off** | **Yrs** | **£** |
|  |  | 0 |

**Average Annual Benefit**  
(excluding one-off)  
**£ 0.9bn**

**Total Benefit (PV)**  
**£ 8.9bn – 15.1bn**

#### Key Assumptions/Sensitivities/Risks

The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence. The energy savings needed to break even are; 3.5% electric and 3% gas.

### Price Base, Time Period, Net Benefit Range (NPV)

<table>
<thead>
<tr>
<th>Year 2007</th>
<th>Years 22</th>
<th>£ -4.4bn (costs) to 1.6bn</th>
<th>£ -1.3bn (cost)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Benefit Range (NPV)</strong></td>
<td><strong>NET BENEFIT (NPV Best estimate)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>What is the geographic coverage of the policy/option?</td>
<td>GB</td>
<td></td>
<td></td>
</tr>
<tr>
<td>On what date will the policy be implemented?</td>
<td>To be arranged</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Which organisation(s) will enforce the policy?</td>
<td>Ofgem</td>
<td></td>
<td></td>
</tr>
<tr>
<td>What is the total annual cost of enforcement for these organisations?</td>
<td>£ N/a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Does enforcement comply with Hampton principles?</td>
<td>N/a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Will implementation go beyond minimum EU requirements?</td>
<td>Yes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>What is the value of the proposed offsetting measure per year?</td>
<td>£ N/a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>What is the value of changes in greenhouse gas emissions?</td>
<td>£ 104m - 636m</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Will the proposal have a significant impact on competition?</td>
<td>Yes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual cost (£-£) per organisation</td>
<td>Micro n/a</td>
<td>Small n/a</td>
<td>Medium n/a</td>
</tr>
<tr>
<td>Are any of these organisations exempt?</td>
<td>no</td>
<td>n/a</td>
<td>N/A</td>
</tr>
</tbody>
</table>

#### Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>Net Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 0</td>
<td>£ 25m</td>
<td>£ -25m</td>
</tr>
</tbody>
</table>

**Key:**  
Annual costs and benefits: Constant Prices  
(Net) Present Value
Summary: Analysis & Evidence

Policy Option: 2b
Description: Mandated 10-year roll out of Automated Meter Reading specification smart meters within existing market structures

<table>
<thead>
<tr>
<th>Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ANNUAL COSTS</strong></td>
</tr>
<tr>
<td>One-off (Transition)</td>
</tr>
<tr>
<td>£12.1bn</td>
</tr>
<tr>
<td>Average Annual Cost (excluding one-off)</td>
</tr>
</tbody>
</table>

Description and scale of key monetised costs by ‘main affected groups’ Transition costs are made up of the asset costs of the meters (£3.2bn), their installation (£2.6bn), communications costs ('Hybrid 2') (£2.5bn) and IT costs. Rollout is expected to begin in 2010 and reduces to new and replacement in 2018, transition costs linked to the meters begin when a meter is installed and these costs are annuitised over the life time of the meter. Legal and IT costs are annuitised over the period. Transition costs include an optimism bias to account for potential risks and optimistic cost estimates. Annual costs are made up of maintenance costs, energy use by the equipment and expected pavement reading inefficiencies (£1.1bn)

| Total Cost (PV) | £10.5bn |

<table>
<thead>
<tr>
<th>Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ANNUAL BENEFITS</strong></td>
</tr>
<tr>
<td>One-off</td>
</tr>
<tr>
<td>£0</td>
</tr>
<tr>
<td>Average Annual Benefit (excluding one-off)</td>
</tr>
</tbody>
</table>

Description and scale of key monetised benefits by ‘main affected groups’ Benefits are made up of reduced energy consumption (£3.1bn), carbon benefits, and a range of additional benefits/ cost savings to suppliers and the industry, including avoided meter reading (£3bn), customer service savings, improved debt management and reduced theft.

| Total Benefit (PV) | £7.2bn – 11.9bn |

Other key non-monetised benefits by ‘main affected groups’ AMR meters are a strong enabling tool for many energy efficiency policies, including supplier obligation, they could also facilitate improve competition.

Key Assumptions/Sensitivities/Risks The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence. The energy savings needed to break even are; 2.92% electric and 3% gas.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV)</th>
<th>Net Benefit (NPV Best estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>22</td>
<td>£-3.2bn (cost) to £1.3bn</td>
<td>£-0.9bn (cost)</td>
</tr>
</tbody>
</table>

- What is the geographic coverage of the policy/option? GB
- On what date will the policy be implemented? To be arranged
- Which organisation(s) will enforce the policy? Ofgem
- What is the total annual cost of enforcement for these organisations? £ n/a
- Does enforcement comply with Hampton principles? n/a
- Will implementation go beyond minimum EU requirements? No
- What is the value of the proposed offsetting measure per year? £ n/a
- What is the value of changes in greenhouse gas emissions? £104m – 636m
- Will the proposal have a significant impact on competition? Yes
- Annual cost (£-£) per organisation (excluding one-off) Micro n/a Small n/a Medium n/a Large n/a
- Are any of these organisations exempt? no n/a N/A N/A

Impact on Admin Burdens Baseline (2005 Prices) (Increase - Decrease)
- Increase of £25m
- Decrease of £25m

Key: Annual costs and benefits: Constant Prices (Net) Present Value
### Summary: Analysis & Evidence

**Policy Option:** 2c  
**Description:** Mandated 10-year rollout of ‘smart box’ technology (equivalent to Automated Meter Reading meter specification) within existing market structures

#### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description and scale of key monetised costs by ‘main affected groups’</th>
<th>Transition costs are made up of the asset costs of the meters (£3.3bn), their installation (£2.2bn), communications costs (‘Hybrid 2’) (£2.5bn) and IT costs. Rollout is expected to begin in 2010 and reduces to new and replacement in 2018, transition costs linked to the meters begin when a meter is installed and these costs are annuitised over the life time of the meter. Legal and IT costs are annuitised over the period. Transition costs include an optimism bias to account for potential risks and optimistic cost estimates. Annual costs are made up of maintenance costs, energy use by the equipment and expected pavement reading inefficiencies (£1.1bn).</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>One-off (Transition) Yrs</strong></td>
<td>£ 11.5bn</td>
</tr>
<tr>
<td><strong>Average Annual Cost (excluding one-off)</strong></td>
<td>£ 0.2bn</td>
</tr>
</tbody>
</table>

**Total Cost (PV)** £ 9.6bn

#### ANNUAL BENEFITS

<table>
<thead>
<tr>
<th>Description and scale of key monetised benefits by ‘main affected groups’</th>
<th>Benefits are made up of reduced energy consumption (£3.1bn), carbon benefits, and a range of additional benefits/cost savings to suppliers and the industry, including avoided meter reading (£3bn), customer service savings, improved debt management and reduced theft.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>One-off Yrs</strong></td>
<td>£ 0</td>
</tr>
<tr>
<td><strong>Average Annual Benefit (excluding one-off)</strong></td>
<td>£ 0.7bn</td>
</tr>
</tbody>
</table>

**Total Benefit (PV)** £ 7.2bn – 11.9bn

#### Key Assumptions/Sensitivities/Risks

The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence. The energy savings needed to break even are; 2.95% electric and 2% gas

#### Other key non-monetised benefits by ‘main affected groups’

AMR meters are a strong enabling tool for many energy efficiency policies, including supplier obligation, they could also facilitate improve competition.

### Key:

- Annual costs and benefits: Constant Prices
- (Net) Present Value

### Price Base

<table>
<thead>
<tr>
<th>Year</th>
<th>Time Period</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>22 years</td>
<td>£ -2.1 (cost) to £2.2bn</td>
<td>£ 0bn</td>
</tr>
</tbody>
</table>

### What is the geographic coverage of the policy/option?

GB

### On what date will the policy be implemented?

To be arranged

### Which organisation(s) will enforce the policy?

Ofgem

### What is the total annual cost of enforcement for these organisations?

£ n/a

### Does enforcement comply with Hampton principles?

n/a

### Will implementation go beyond minimum EU requirements?

no

### What is the value of the proposed offsetting measure per year?

£ n/a

### What is the value of changes in greenhouse gas emissions?

£ 104m – 636m

### Will the proposal have a significant impact on competition?

yes

### Annual cost (£-£) per organisation (excluding one-off)

<table>
<thead>
<tr>
<th>Micro</th>
<th>Small</th>
<th>Medium</th>
<th>Large</th>
</tr>
</thead>
<tbody>
<tr>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

### Are any of these organisations exempt?

no

### Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>Net Impact (Increase - Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>£</td>
<td>£ 25m</td>
<td>£ -25m</td>
</tr>
</tbody>
</table>

Key: Annual costs and benefits: Constant Prices (Net) Present Value
### Summary: Analysis & Evidence

**Policy Option:** 2d  
**Description:** Mandated new and replacement roll out of Automated Meter Management specification smart meters within existing market structures

#### ANNUAL COSTS

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Years</th>
<th>Cost (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>One-off (Transition)</td>
<td></td>
<td>20</td>
<td>7.5bn</td>
</tr>
</tbody>
</table>

**Average Annual Cost (excluding one-off):** £0.2bn

**Total Cost (PV):** £8bn

#### ANNUAL BENEFITS

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Years</th>
<th>Cost (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>One-off</td>
<td></td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

**Average Annual Benefit (excluding one-off):** £0.5bn

**Total Benefit (PV):** £5bn – 8.5bn

**Other key non-monetised benefits** by ‘main affected groups’ AMM meters are a strong enabling tool for many energy efficiency policies, including supplier obligation they could also facilitate improved competition, wider network benefits and demand side load shifting.

#### Key Assumptions/Sensitivities/Risks

The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence. The energy savings needed to break even are: 4.65% electric and 3% gas.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period (Years)</th>
<th>Net Benefit Range (NPV)</th>
<th>NET BENEFIT (NPV Best estimate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>22</td>
<td>£-2.8bn (cost) to £0.3bn</td>
<td>£-1.2bn (cost)</td>
</tr>
</tbody>
</table>

- **What is the geographic coverage of the policy/option?** GB
- **On what date will the policy be implemented?** To be arranged
- **Which organisation(s) will enforce the policy?** Ofgem
- **What is the total annual cost of enforcement for these organisations?** £ N/a
- **Does enforcement comply with Hampton principles?** n/a
- **Will implementation go beyond minimum EU requirements?** Yes
- **What is the value of the proposed offsetting measure per year?** £ n/a
- **What is the value of changes in greenhouse gas emissions?** £64m – 374m
- **Will the proposal have a significant impact on competition?** Yes
- **Annual cost (£-£) per organisation**
  - Micro: n/a
  - Small: n/a
  - Medium: n/a
  - Large: n/a
  - No
- **Are any of these organisations exempt?** n/a

#### Impact on Admin Burdens Baseline (2005 Prices)

<table>
<thead>
<tr>
<th>Increase of (£)</th>
<th>Decrease of (£)</th>
<th>Net Impact (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase of 25m</td>
<td>Decrease of 0</td>
<td>£25m</td>
</tr>
</tbody>
</table>

**Key:**  
Annual costs and benefits: Constant Prices  
(Net) Present Value
### Summary: Analysis & Evidence

<table>
<thead>
<tr>
<th>Policy Option: 3</th>
<th>Description: Mandated 10-year roll out of Automated Meter Management specification smart meters in a regional franchise market model</th>
</tr>
</thead>
</table>

#### ANNUAL COSTS

<p>| Description and scale of key monetised costs by ‘main affected groups’ Transition costs are made up of the asset costs of the meters (£5.2bn), their installation (£2.3bn), communications costs (‘Hybrid 2’) (£2.7bn) and IT costs. Rollout is expected to begin in 2012 and reduces to new and replacement in 2020, transition costs linked to the meters begin when a meter is installed and these costs are annuitised over the life time of the meter. Legal and IT costs are annuitised over the period (from 2010). Transition costs include an optimism bias to account for potential risks and optimistic cost estimates. Annual costs are made up of maintenance costs, energy use by the equipment and expected pavement reading inefficiencies (£0.7bn). |</p>
<table>
<thead>
<tr>
<th>One-off (Transition)</th>
<th>Yrs</th>
<th>£</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 15.4bn</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>

**Average Annual Cost (excluding one-off)**

| £ 0.3bn |

**Total Cost (PV)** £ 12.7bn

#### ANNUAL BENEFITS

<p>| Description and scale of key monetised benefits by ‘main affected groups’ Benefits are made up of reduced energy consumption (£3bn), avoided peak consumption, carbon benefits, and a range of additional benefits/ cost savings to suppliers and the industry, including avoided meter reading (£2.9bn), customer service savings, lower working costs for prepayment meters, improved debt management, reduced theft and savings for microgen users. |</p>
<table>
<thead>
<tr>
<th>One-off</th>
<th>Yrs</th>
<th>£</th>
</tr>
</thead>
<tbody>
<tr>
<td>£ 0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Average Annual Benefit (excluding one-off)**

| £ 0.9bn |

**Total Benefit (PV)** £ 8.6bn – 14.6bn

**Other key non-monetised benefits by ‘main affected groups’ AMM meters are a strong enabling tool for many energy efficiency policies, including supplier obligation they could also facilitate improved competition, wider network benefits and demand side load shifting.**

### Key Assumptions/Sensitivities/Risks

The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence. The energy savings needed to break even are: 3.85% electric and 3% gas.

<table>
<thead>
<tr>
<th>Price Base Year</th>
<th>Time Period Years</th>
<th>Net Benefit Range (NPV) £ -4.0bn (cost) to £1.9bn</th>
<th>NET BENEFIT (NPV Best estimate) £ -1.0bn (cost)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>22</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**What is the geographic coverage of the policy/option?** GB

**On what date will the policy be implemented?** To be arranged

**Which organisation(s) will enforce the policy?** Ofgem

**What is the total annual cost of enforcement for these organisations?** £ n/a

**Does enforcement comply with Hampton principles?** n/a

**Will implementation go beyond minimum EU requirements?** yes

**What is the value of the proposed offsetting measure per year?** £ n/a

**What is the value of changes in greenhouse gas emissions?** £ 102m – 622m

**Will the proposal have a significant impact on competition?** yes

**Annual cost (£-£) per organisation**

<table>
<thead>
<tr>
<th>Micro</th>
<th>Small</th>
<th>Medium</th>
<th>Large</th>
</tr>
</thead>
<tbody>
<tr>
<td>n/a</td>
<td>n/a</td>
<td>N/A</td>
<td>n/a</td>
</tr>
</tbody>
</table>

**Are any of these organisations exempt?** no

**Impact on Admin Burdens Baseline (2005 Prices)**

<table>
<thead>
<tr>
<th>Increase of</th>
<th>Decrease of</th>
<th>£ 25m</th>
<th>Net Impact</th>
<th>£ -25m</th>
</tr>
</thead>
</table>

**Key:** Annual costs and benefits: Constant Prices (Net) Present Value
## Summary: Analysis & Evidence

<table>
<thead>
<tr>
<th>Policy Option: Small Business</th>
<th>Description: Indicative assessment for small businesses – defined as those in electricity profile classes 3 &amp; 4 and/or with gas consumption 73-732MWh/year</th>
</tr>
</thead>
</table>

### ANNUAL COSTS

- **One-off (Transition)**: £0.6bn for 20 years
  - Transition costs are made up of the asset costs of the meters, their installation, communications costs ('Hybrid 2') and IT costs. Rollout is expected to begin in 2010, transition costs linked to the meters begin when a meter is installed and these costs are annuitised over the life time of the meter. Legal and IT costs are annuitised over the period (from 2010). Transition costs include an optimism bias to account for potential risks and optimistic cost estimates. Annual costs are made up of maintenance costs, energy use by the equipment and expected pavement reading inefficiencies.

### ANNUAL BENEFITS

- **One-off**: £0
  - Benefits are made up of reduced energy consumption, avoided peak consumption, carbon benefits, and a range of additional benefits/ cost savings to suppliers and the industry, including avoided meter reading, customer service savings, improved debt management, reduced theft, changing profile class and savings for microgen users.

### Key Assumptions/Sensitivities/Risks

- The majority of the benefits (and costs) are assumptions produced after discussions with the industry. Energy savings depend on the behavioural response of consumers to smart meters; we have made a best estimate considering the current evidence.

### Price Base

- **Year 2007**

### Net Benefit Range (NPV)

- **£0.5 to 2.2bn**

### NET BENEFIT (NPV Best estimate)

- **£1.6bn**

### What is the geographic coverage of the policy/option? GB

### On what date will the policy be implemented? To be arranged

### Which organisation(s) will enforce the policy? Ofgem

### What is the total annual cost of enforcement for these organisations? £n/a

### Does enforcement comply with Hampton principles? n/a

### Will implementation go beyond minimum EU requirements? yes

### What is the value of the proposed offsetting measure per year? £n/a

### What is the value of changes in greenhouse gas emissions? £16m – 216m

### Will the proposal have a significant impact on competition? yes

### Annual cost (£-£) per organisation (excluding one-off)

<table>
<thead>
<tr>
<th>Micro</th>
<th>Small</th>
<th>Medium</th>
<th>Large</th>
</tr>
</thead>
<tbody>
<tr>
<td>£n/a</td>
<td>£n/a</td>
<td>£n/a</td>
<td>£n/a</td>
</tr>
</tbody>
</table>

### Are any of these organisations exempt?

- No

### Impact on Admin Burdens Baseline (2005 Prices)

- **Increase of £25m**

### Key:

- Annual costs and benefits: Constant Prices (Net) Present Value
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A. Strategic Overview

The Energy White Paper published in May 2007\(^1\) sets out the Government's international and domestic energy strategy for responding to the challenges of climate change; and to ensure secure, clean and affordable energy as we become increasingly dependent on imported sources of energy.

Four energy policy goals have been set for the strategy:

- The draft Climate Change Bill creates a new legal framework for the UK achieving, through domestic and international action, at least a 60% reduction in carbon dioxide emissions by 2050, and a 26-32% reduction by between 2018 and 2022, against a 1990 baseline;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond;
- to ensure that every home is adequately and affordably heated.

Using energy more efficiently is recognised as a way to cut carbon dioxide emissions. It can also improve productivity and can contribute to the security of our energy supplies by reducing our reliance on imported sources of energy and ensuring we make maximum use of our own and global energy resources. Improving the energy efficiency and reducing the energy usage of homes can also reduce energy bills and help ensure that the most vulnerable can afford to heat their homes.

In the Energy White Paper (2007) the Government set out its intention to improve awareness of climate change and information on energy use by providing historical information on energy bills and requiring energy suppliers to provide electricity displays free at the point of request and for all new and replacement meters. The White Paper also set out Government's expectation that smart electricity and gas meters would be installed within every home over the next decade. The Government then consulted on proposals for taking forward this proposed policies in an August 2007 consultation on metering and billing issues\(^2\).

The economic modelling used here was developed for the domestic sector and includes micro businesses where the consumption levels are similar. We have extended the work to begin to explore the potential of smart metering for the small business sector (electricity profile classes 3 & 4 and gas consumption 73-732MWh/year) which we estimate covers approximately 2 million electricity meters and 0.4 million gas meters. Some preliminary results are presented, but this is identified as an area for more detailed specific work.

The smart meters policy options have been developed in the context of the above objectives.

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B. The issue

Within the current domestic and small business energy market in Great Britain there are information failures for both consumers and suppliers. On average suppliers only know how much a household or small business consumes after a quarterly read and consumers are generally only aware of consumption on a quarterly, historic basis. In addition many of those quarterly reads are not actual reads undertaken by the supplier but estimates or readings taken by the consumer. Whilst some suppliers do read meters more frequently there is only an obligation to do this once every two years.

Consumers have no simple way of gaining dynamic and useful information in order to manage, and reduce, consumption. In addition problems with accuracy of data and billing create costs for suppliers and consumers, causing problems in terms of disputes over bills (complaints) and problems with the change of supplier process, and possibly hindering competition.

Smart meters with a real-time display would help address these issues, enabling consumers and suppliers to access more information about energy use and cost. Analysis by Sarah Darby which summarised a number of international studies showed potential energy savings from the provision of feedback on energy use. Smart meters also offer the possibility of remote communication between the meter and the supplier facilitating, amongst other things, more efficient collection of billing information, the development of more sophisticated tariff structures and demand management approaches that could be used to further incentivise energy efficient behaviour by consumers and suppliers alike.

The benefits from a roll out of smart meters together with a visual display fall to a number of actors – to customers (in terms of accurate bills, accurate and real-time information to enable them to reduce energy consumption and potentially new services), to suppliers (in terms of more frequent information, reduced service costs to serve) and to the society (in terms of reduced carbon emissions). There are also potential benefits for network companies in terms of using the data collected via smart metering to better identify technical losses and electricity outages, and to better inform long-term investment in the network.

In the absence of Government intervention, a roll out of smart meters would probably take place for gas pre-payment customers and those whose meters were particularly hard to access, where suppliers can make a positive business case. This may be for around 20-30% of meters, and this would affect the business case for other segments; potentially leading to a “tipping point” where the cost of maintaining the stock of non-smart meters outweighed the cost of installing smart meters. In practice, experience from other countries shows that suppliers and others interested in meter provision, such as meter-owners (at least in competitive markets) rarely fully embrace smart metering unless or until Government either explicitly requires provision of smart meters, or requires the provision of services which cannot be delivered, or are uneconomic to provide without smart meters.

The Government, having announced its vision for the roll out of smart meters, recognises that suppliers are now waiting for the Government to take a lead before taking decisions on how to move forward in this area. Given the economic and technical factors involved in a universal smart meter roll out, Government intervention may be needed both in terms of setting the requirements for suppliers which will lead them to adopt smart meters, and in terms of how smart metering will

---

1 Sarah Darby, The Effectiveness of Feedback on Energy Consumption, April 2006
be delivered and the risks associated with it. This impact assessment assesses various options going forward.

The Government also has obligations under the EU Energy Services Directive which requires that customers have access to a range of improved energy consumption and billing information, which smart meters will facilitate.\(^4\)

\(^4\) Article 13 of the Energy End-Use Efficiency and Energy Services Directive 2006/32/EC
C. Objectives

The overall objective of Government intervention in the metering market is to secure as widespread and rapid adoption of smart metering services as possible in order to deliver accurate, timely information on energy usage to both consumers and suppliers in order to:

a) secure savings in energy usage; and

b) improve the functioning of the energy markets, in particular to reduce problems for consumers and suppliers associated with inaccurate data, and facilitate the development of markets for energy services.

As a consequence of this objective a range of outcomes will be facilitated or made possible:

- **Energy savings and related carbon savings** in terms of overall savings, savings at peak as well as provision of accurate energy consumption data to consumers which enables improved and better targeted energy efficiency advisory services, expanding the range and improved targeting of Carbon Emissions Reduction Targets (CERT)\(^5\) measures. Under a post-2011 Supplier Obligation (one potentially requiring suppliers to deliver absolute reductions in their consumers’ household carbon) smart meters could be a key enabler and facilitate suppliers in formulating (competitive) bespoke energy services packages;

- **Accurate bills and consumption data** to ensure consumers are billed accurately and to open up the possibility of more frequent billing;

- **Facilitating the development of demand management and other innovative services and tariffs** through the provision of accurate data and the potential (depending on technology) to remotely change the meter;

- **Improved customer service and experience**. A variety of issues are covered here: reducing complaints associated with billing and meter exchanges; reducing problems associated with data which cause exceptions in the change of supplier process; enabling consumers to select new tariffs and for suppliers to transfer consumers on to the new tariff remotely; removal of the need to stay at home for meter readings; easier switching between pay-as-you-go / credit tariffs; and a reduction in the service costs associated with pre-payment meters (PPMs);

- In the longer-term **improved network management** via accurate energy efficiency consumption data to enable better informed investment decisions, detection of losses etc, as well as lower overall consumption reducing pressure on the network;

- **Facilitation of wider policy goals**: Smart meters also act as a facilitation measure for a variety of other policy areas. Increased information about energy consumption can inform future policy development on energy efficiency. High-end specification smart meters can also measure export of microgeneration. Finally, smart meters may help to boost the development of

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\(^5\) Obligation on energy suppliers to achieve targets for promoting reductions in carbon emissions in the household sector

http://www.defra.gov.uk/environment/climatechange/uk/household/supplier/index.htm
smart homes more widely including improved management and networking of domestic appliances, and facilitating other goals e.g. water conservation and care services for vulnerable sectors of society.

**Aims:**
- Smart metering together with displays to all domestic households and small businesses;
- All consumers and small businesses have 100% accurate bills for gas and electricity;
- Reduction in energy consumption
- A reduction in costs to serve for PPMs;
- Development of CERT innovation ring-fence measures using smart metering before 2011;
- Delivery of smart-enabled energy efficiency measures under the Supplier Obligation after 2011 enabling Government at least to meet published aspiration of savings when the Supplier Obligation is finalised.

Energy supply markets in Great Britain are generally amongst the most competitive in the world. It will be necessary to find a way of enabling the industry to deliver the outcomes described above that involves sufficient incentives for efficient delivery to ensure that, while maintaining high technical standards, costs are minimised and the potential for innovation maximised wherever possible. This must also include consideration of competition in new markets for the provision of innovative energy services, which depend on the existence of smart metering but should be capable of being delivered by energy services companies as well as energy suppliers.
D. Options Identification

In terms of options identification the key areas considered are meter functionality, roll out speed and market model – these are discussed briefly in this section and the options selected set out. It is envisaged that any Government mandate to roll out smart metering would be likely to be limited to defining a minimum level of functionality for the meters and the timescale for delivery. In addition Government intervention would be required to ensure that an appropriate metering market model was in place. It should be noted that there are many variables in assessing policy options for a smart meter roll out, including: cost of meter technology/functionality, speed of roll out, market model of roll out and communications costs.

Meter functionality

There is no single widely accepted definition of a ‘smart meter’. Smart meters can have varying degrees of functionality from one-way, to two-way communication. They may incorporate additional functionality – for instance for measuring electricity exported to the grid from micro-generation or the ability to switch between credit and pre-pay functions or different tariffs remotely. We have analysed two meter-centric approaches and one where the smart functions are contained in a separate unit, known as a “smart box”. The technology options deliver two levels of functionality as follows:-

- **Automated Meter Reading functionality (AMR).** A meter which delivers AMR functionality is capable of storing measured electricity consumption data for multiple time periods and provides one-way communications from the meter to allow remote access to that consumption data. The smart box approach also delivers AMR functionality.

- **Automated Meter Management functionality (AMM).** A smart meter at the AMM level delivers the same functionality as an AMR meter, but also has two-way communications which enable it to be updated remotely and permits provision of time-of use tariffs. The AMM model we have assessed also measures microgeneration exported (electricity meter) to the grid and has the ability to switch consumers between credit and pre-pay and to disconnect them remotely.

For the purposes of this analysis we have selected the broad options above as representative of the likely range of costs – this does not mean that Government is bound to select either of these or indeed any particular technology for a roll out.

Speed of roll-out

The length of time it takes to roll-out smart meters determines the speed with which the stated benefits come on stream. The options considered in this analysis are either for a mandated ten-year roll-out of smart meters or for smart meters to be installed on a new and replacement basis – that is a smart meter would be installed wherever a new connection is made or where a meter has to be replaced – which could take up to 20 years (the nominal life of an accurate meter). A number of issues can be contrasted with different speeds of smart meter roll-out:

- with a longer roll out he need for suppliers to run two “back-office” systems, one to support the old meter stock and one for smart meters, will be extended and therefore costs are likely to be higher;
- any roll out of smart meters will require equipment, enough trained and competent people and availability of meters, risk of boom and bust cycles for participant firms. In an accelerated roll out pressures on capital costs and availability may be increased;
• **dual fuel** – where one supplier provides gas supply and another electricity to the same address appropriate structures will need to be in place to ensure a smooth roll out of smart meters and this may be more difficult in a new and replacement approach as opposed to an accelerated roll out; and

• **stranding costs** – a cost incurred where a non-smart meter is removed before the end of its anticipated life – this is known as the “stranding” of the asset and carries a cost, this would occur under any accelerated scenario.

**Display Devices**

A display or display device means a device that is capable of providing the customer with information about electricity consumption and the cost of such consumption at the time at which such consumption occurs. The display is connected via a wireless connection to the smart meter. Throughout this analysis it is assumed that the smart meter would be provided with such a display which we refer to as a Real Time Display Device (RTD).

**Options**

The following scenarios have been selected to test the variables outlined above; in addition these options also assess the impact of different market approaches to the roll out. Options 1-3 are considered to offer a representative range of technology/functionality options, roll out speeds and compare a roll out in a managed, centralised approach to that using a fully competitive approach. These options are analysed quantitatively and the results presented in Section E.

It is important to note that options 3, 4 and 5 described above all raise potentially significant legal and regulatory issues and these would need to be resolved before this was a workable way forward. It is anticipated that a degree of regulatory intervention would be required from Ofgem to ensure consumers’ interests are properly protected to varying degrees across all the options.

It is recognised that other approaches could be taken and three of these are described below (options 4-6). However these have not been considered in quantitative terms because it is believed that the results would broadly equate to those where the analysis has been carried out and the more concrete differences would be qualitative. More detailed qualitative description is provided of all six options in Annex 1.

**Option 1:** *No domestic smart metering mandate but a better billing and displays policy*

This option assumes no Government intervention on domestic smart metering but includes the implementation of the policies on billing (primarily provision of historic comparative data) and displays set out in the August 2007 consultation on billing and metering⁶.

**Option 2a-d:** *Mandated rollout of smart metering within existing metering market structures with varying technology levels and varying roll out timescales.*

The Government would require suppliers to provide smart meters with displays over a defined time period with a defined level of functionality. Suppliers would be responsible for contracting for metering services to deliver the Government’s mandate. The quantitative analysis examines the following options:-

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⁶ A ‘do nothing’ option has not been analysed because the Government has commitments under the ESD, which it must implement, regardless of whether smart meters are rolled out – also refer to discussion on “benchmarking” at pp36.
• **Option 2a**: Mandated 10-year roll out of AMM specification smart meters within existing market structures
• **Option 2b**: Mandated 10-year roll out of AMR specification smart meters within existing market structures
• **Option 2c**: Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures
• **Option 2d**: Mandated new and replacement roll out of AMM specification smart meters within existing market structures.

**Option 3**: Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model

A managed option involving the roll out of AMM smart meter over 10 years. Known as the Regional Franchise Model (RFM) this approach was proposed by the Energy Retail Association (ERA). It would involve a competitive tendering process to select a regional franchise to purchase, install and operate smart meters. The franchisee would provide the communications and data infrastructure and associated support functions in a given region for a time-limited period. The proposal would be for the first franchise to last the duration of the roll out period or alternatively to be a longer term and ongoing arrangement.

A variant on the model proposed above would be to create a new licensable activity, this would combine the market elements described above, (a competitive tendering process) but with the regulatory oversight described under Option 4 below.

**Small Businesses**

We have extended the economic modelling used for the above options to begin to explore the potential of smart metering for the small business sector. This sector covers electricity profile classes 3 and 4 and for gas consumption 73-732MWh/year. We have considered various options to roll out smart metering to this sector which accord with the technology/functionality, market and timescales analysed for options 2a-d and 3 above. Some indicative results are presented in Section E, however this is a very early analysis for this sector and this area requires further work.

**Qualitative analysis only (see also annex 1)**

**Option 4**: Mandated Smart metering rollout through Distribution Network Operators (DNOs) (for electricity) and Gas Distribution Networks (for gas)

This is an alternative managed approach where the functions to support smart metering would be attributed to existing gas and electric DNOs/Gas Distribution Networks. There would be no competitive element to this approach and this work would be fully regulated as a licensable activity by Ofgem and subject to price controls. The DNOs/Gas Distribution Networks would purchase, install and operate smart meters and displays. They would provide resilient communications, a data infrastructure and other associated support functions.

**Option 5**: Infrastructure provider for a 10 year rollout

This is an alternative managed approach where the new market functions required for implementing and operating smart metering and displays (the provision of resilient communications, data infrastructure and associated support functions) are provided on a national or regional basis by a single service provider. The smart meters would
then be installed by suppliers and linked into the regional (or national) communications infrastructure, resolving any issues around interoperability and aiding switching processes.

**Option 6: Indirect government mandate**

This option focuses on the type of regulatory intervention required to deliver smart metering within existing market structures. This would be a hands-off approach where the Government would not prescribe smart meters, but would define policy outcomes to be delivered over a set timetable. For example this approach may follow that adopted in Sweden with a mandate for clear and accurate monthly bills. In practice an obligation on suppliers to provide consumers with accurate monthly bills would translate into a roll-out of smart metering, because this would be the only guaranteed method of delivering the obligation without incurring excessive costs.

Government could define various outcomes which would effectively ensure the delivery of smart metering to different levels of functionality. In addition it would also be possible to envisage some hybrid of an outputs-based approach combined with more specific mandates for instance on meter technology or the roll-out length.
E. Analyse the options

In this section we describe the main assumptions made in the analysis and the reasons for them, including any references or discussions. These assumptions are generally shared between the policy options already outlined, with any differences noted. An economic model has been used to analyse the options using these assumptions and to calculate the results which are presented below.

It should be noted that within the economic model all up-front costs are annuitised over the lifetime of the meter or over a 20 year period. The modelling assumes that a loan is required to pay for the asset, which is then repaid over the period. Following BERR guidance a cost of capital of 10% has been assumed. We have been informed by some suppliers that their commercial approach would be likely to use a lower cost of capital. The benefits are not annuitised but are represented annually.

1. Smart metering functionality – assumptions

We consider two main variations of smart technology – AMR and AMM. AMR (Automated Meter Reading) enables the meter to send readings to the supplier as often as required, thus needing one-way communications technology. AMM (Automated Meter Management) is an additional function to AMR that allows suppliers or meter operators to have full control of the meter functions and configuration through two-way communications. This allows communication direct with customers, remote switching from credit to debit function and potentially remote connection and disconnection.

**AMR smart meter**

This is an example of a minimum smart meter specification. The ‘smart-enabled’ meters have the following characteristics:

- Fully compliant with the Measuring Instruments Directive (MID)
- Import capability (export capability is optional for electricity meters)
- Two-tariff capability (more rates optional)
- Minimum data storage capability
- Time clock (for time stamping stored records)
- Local communications (to the display and other meter)

As suggested this option could be built on to improve its capabilities, but we are assuming only the minimum level.

There has been some interest in a modular approach where a “basic” meter is produced, which had the capability of adding additional functions (either physically or through software) which would allow suppliers to differentiate themselves with the offer of increased functionality. Adding functionality through additional modules should not be allowed to become a barrier to switching.

We shall assume that a minimum specification smart meter (with the above capabilities) would cost £10 more than an existing meter, resulting in costs for a single phase ‘smart-enabled’ electricity meter without an RTD is £17 and £28 for a gas meter. For prepayment meters (PPM) we assumed the an additional £10 cost to that currently seen in the market. Both external and internal communications costs are assumed to be additional costs, discussed later in the communications section.

**AMM smart meter**

In addition to the functionality AMR spec the AMM specification should also have:

- Electricity meters with import/export capability
• Two-way communications between the meter and the supplier
• Remote configuration
• Multi-tariff capability
• Remote switching between credit and debit function
• Remote connect/disconnect capability
• Advanced data processing capability

The capital cost for the AMM specification produced extensive discussion in the consultation documents. With estimates ranging from £50 to £80 for the electric meter and £60-£100 for the gas meter, generally including the RTD, communications and in some cases installation. We considered these costs and have decided to use estimates produced from consulting a range of meter manufacturers and suppliers as well as building up the specification from the AMR cost. We have separated out the internal and external communications costs from the meter (including them later in the communications section) resulting in a cost of £47 for the electricity meter and £60 for the gas. These costs are at the lower end of the consultation responses but do not include an RTD and communications (included later). These costs are the same for the PPM meters as they will no longer be different meters.

The additional aspects of this specification facilitate a range of additional benefits:

• two-way communications allow the supplier to send data to the meter (i.e. tariff changes);
• remote configuration of the meter could reduce costs to serve and increase the level of service to customers including facilitating ease of switching between suppliers and tariffs;
• there would be the opportunity for the introduction of time of use tariffs and in the long term it may enable real time network management.
• a full range of benefits for Pre-Payment Meters (PPM) including allowing for remote switching between credit and pre-pay, the ability to offer a range of competitive tariffs in this sector (given the reduced costs to serve).
• potentially provide the ability for remote disconnection.
• could facilitate distributed generation (i.e. microgeneration) without the need for a second meter. Although a second meter would be required for Renewable Obligation Certificates (ie to measure actual electricity generated rather than just exported back to the grid)\(^7\)

**Dumb meter / Smart box**

The dumb meter/ smart box is not a smart meter but has smart capabilities provided through a device separated from the actual physical meter. Consumption data is transmitted from the standard “dumb” meter to a “smart” box that contains the external communications module; the data are then transmitted through data hubs back to suppliers. The technology solution examined here is classified as AMR, but in principle this approach could deliver some AMM functionality.

We assume that the total cost will be £17 for one electricity smart box, and a gas pulse meter with a transmitter piggybacking on the electricity smart box would cost £18 (including the cost of having to install 50% of gas meters to allow them to be retrofitted); without communications costs included (more detail in annex 3). We appreciate that little is known about the costs of this technology option and therefore we cannot fully verify these estimates at the moment. It should be noted that the

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\(^7\) Whilst we acknowledge that this measurement could be performed by one smart meter there are technical and potential aesthetic constraints that make this option unattractive and, as such, not considered further within this document.
dumb meter/ smart box option does not apply to PPMs (although PPM households will still use a Real Time Display)⁸.

**Real Time Display**

Real time displays will be linked to the meter through local communications so that customers can view their real time usage of energy. We assume all electricity meters will come with an RTD, and the gas meter will share this RTD, thus ensuring only one per household. We assume that an RTD costs £15. This figure was used previously by BERR and it remained largely undisputed by stakeholders in response to the BERR impact assessment of real time displays to domestic electricity consumers.

**Table 1: Summary of capital costs £ per meter**

<table>
<thead>
<tr>
<th>Capital Costs (£/m)</th>
<th>Electricity</th>
<th>Elec PPM</th>
<th>Gas</th>
<th>Gas PPM</th>
</tr>
</thead>
<tbody>
<tr>
<td>RTD Only</td>
<td>15.0</td>
<td>15.0</td>
<td>15.0</td>
<td>15.0</td>
</tr>
<tr>
<td>Basic Meter</td>
<td>7.0</td>
<td>45.0</td>
<td>18.0</td>
<td>100.0</td>
</tr>
<tr>
<td>Dumb and Smart</td>
<td>17.0</td>
<td>9.0</td>
<td>18.0</td>
<td>9.0</td>
</tr>
<tr>
<td>AMR Spec</td>
<td>17.0</td>
<td>55.0</td>
<td>28.0</td>
<td>110.0</td>
</tr>
<tr>
<td>AMM Spec</td>
<td>47.0</td>
<td>47.0</td>
<td>60.0</td>
<td>60.0</td>
</tr>
</tbody>
</table>

It is assumed that due to technological advancement the costs of the meters will fall over time. This has been seen with the current meters and internationally for smart meters. We assumed that costs would fall by 1% per annum, resulting in 20% over the period. This is applied at three time periods, 2010, 2017 and 2024.

Different levels of optimism bias are applied to the different specifications to consider the risk associated with the options. More detail can be found in the risk section.

2. **Benefits of Smart Metering**

**Behavioural changes:**

Benefits from Smart Meters can be driven by changes in consumers’ expected consumption behaviour. There are two potential sources of change in consumption behaviour that may arise:

- a reduction in overall energy consumption as a result of better information on costs and usage of energy which drives behavioural change and;
- A shift of energy demand from peak times to off-peak times (considered later).

**Energy Savings**

There is a great deal of uncertainty about the likely response of consumers to the full roll out of smart meters. Although a number of international studies exist (summarised by Sarah Darby⁹), sometimes showing dramatic behavioural changes (over 10%), it is usually very hard to transfer the findings to the UK situation (e.g. mandatory take-up expected here, very little use of air conditioning, different counterfactual world, different cultures, different price levels). Most commentators have adopted relatively conservative assumptions. Ofgem’s cost-benefit analysis assumed a 1% energy saving realised from smart meters, which is at the lower end of the saving (1-3%) reported in the Owen and Ward (2006, 2007). Other studies have been more optimistic. Energywatch gives a range of energy saving of 3.5-7%.

It is worth noting that Darby reported that the majority of the savings were the result of real time information.

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⁸ Further detail on this approach can be found in the MML report
⁹ Sarah Darby “The Effectiveness of Feedback on Energy Consumption” April 2006
For our analysis we have split consumers into three categories of enthusiasts, followers and laggards, and then applied different saving rates, and assumed that the following gross annual reductions in demand will take place as a result of improved feedback on the use and cost of energy: 2.8% for electricity; 2% for gas credit and 0.5% for gas PPM. We applied sensitivity analysis up to 4% for electricity credit meters and 4% for gas credit users (and down to 1.5% and 1% respectively) with corresponding improvements for PPM have also been proposed.

None of the previous studies appear to have taken into account the energy requirements of the metering, display and communications equipment, which should be included in order to provide net energy savings. We have held discussions with meter specialists and they suggest that the additional smart equipment costs could be 1.25w/h for the meter including communications and 0.6w/h for the RTD.

Valuing Energy Reductions

The roll out of energy efficiency measures will lead to reductions in energy consumption. The main development is that a comparison between the residential and base load profile (electricity) has been taken into account, i.e. residential electricity use is concentrated at peak times compared with general wholesale electricity. The proposal and assumptions are explained in Annex 2.

Time of use tariff

Alongside changes in consumers’ consumption behaviour resulting in lower energy demand, another potential source of change in consumption patterns through smart meters is a shift of energy demand from peak times to off-peak times.

This shift in consumption is said to arise because smart meters allow and facilitate the introduction of time of use (ToU) tariffs that charge customers significantly lower prices for off-peak (midday and night) use of energy than for peak use (morning and evening hours). This should incentivise switching electricity demand into off peak hours. Benefits from shifting energy consumption from peak to off-peak times materialise as cost reductions for consumers, suppliers and eventually network operators.

A range of consultation responses argued that a shift of energy demand from peak to non peak hours will take place if customers have a sufficiently large financial incentive, through ToU tariffs to run appliances during off-peak periods. How much benefit suppliers will receive once this incentive structure is in place is difficult to tell. If customers cannot shift demand effectively then suppliers will benefit from higher prices.

After considering the limited amount of load shifting that may be possible through standard ‘wet’ household appliances; the unpredictable developments in ToU tariffs; international evidence; and the likeliness of take up of ToU tariffs in Great Britain; BERR decided that the benefits from ToU tariffs considered in this IA should be conservative. We shall consider a 20% take up by consumers of the ToU tariff and a 3% bill reduction as a result; sensitivities will be made on the percentage take up at 0 and 40%. It may be possible that future technology developments, such as the development of smart homes services and smart home appliances, may lead to a future increase of similar benefits.

This benefit is only gained with the AMM meter.
Valuing avoided costs of carbon from energy savings

BERR has valued the avoided costs of carbon delivered from the savings of energy through smart meters\(^{10}\). New methodology from Defra and BERR suggests that carbon savings from the reduction in electricity use are already picked up in the EU Emissions Trading Scheme. Allowances are held by energy producers and costs passed through to consumers through the household retail price. As a result the carbon savings have already been accounted for within the EU ETS.\(^{11}\) The electricity price already includes the EU ETS price which is passed on from producers. As a result of this the summary sheet only has the carbon savings for gas.

BERR has valued carbon savings from a reduction in gas consumption using the Shadow price of carbon (SPC) based on Defra guidance.

Peak load reduction

Peak load reduction is a consequence of overall energy savings within the home and as a result there are avoided costs to the network. After considering the estimates from Mott MacDonald Ltd (MML), Frontier Economics and National Grid for savings from investment reductions on distribution and transmission from peak load reduction, we decided that these benefits are included in the long run retail component of the energy price which we assumed to be 53% for electricity, 46% for electricity PPM, 55% for gas and 47% for gas PPM.

The workings for the peak load reduction are still necessary when considering the affect of ToU tariffs on the network from peak load shifting. We assumed the value of shifted load per year to be £0.43 and a 5% shift in peak.

Valuing consumer time savings

Smart technology may allow improved service provision by providing accurate, timely data, therefore reducing complaints and disputes between customers and suppliers. The supplier benefits from a reduction in complaints are included in the supplier benefits section below. The potential benefit to consumers is from a reduction in the time spent making complaints and waiting in for the meter to be read. After considering the estimates for consumer time savings from smart metering used by Energywatch and considering the potential time costs caused by the smart technology (time spent reviewing more complicated bills and the RTD and more frequent meter replacement), it may be possible that potential consumer time savings are likely to be matched by the potential time costs caused by smart technology (more detail can be found in annex 3). We have in any case not included this saving as consumer time estimates are not used in Energy IAs.

Microgeneration

We have considered the idea that smart meters will improve the linking of microgen units back to the grid as they could include export capability. We have attempted to estimate this saving by estimating the amount of microgen units that will be in use in 2020 by the estimated saving which we would expect a smart meter to allow. After initial discussions we have made a conservative estimate of the number of units and the saving (assuming a separate meter is not needed and its installation cost) and

\(^{10}\) BERR has not netted off the carbon emissions embodied in production and transportation metering equipment. The analysis thus assumes that all meters are carbon-neutral throughout their lifecycle. The energy use (and carbon emissions) of the smart meter, RTD and comms are included later.

\(^{11}\) This methodology is still being developed within BERR and Defra.
produced savings per annum per meter of a few pence. Further work is needed in this area to better understand the number of units and the potential savings.

**Supplier benefits**

Supplier benefits are the cost reductions that suppliers will see once smart meters are installed. The consultation responses highlighted a range of possible supplier benefits. Some of the potential supplier benefits are not included as benefits to society as they are transfers from consumers to suppliers with no overall changes for society. The following are the main supplier benefits used in the IA.

**Meter reading**

Smart meters will allow meter reading savings for all the suppliers once the roll out is complete. Responses to the consultation suggested this cost saving would be between £4 and £14 per meter per annum. We shall assume that the cost savings will be £6 per (credit) meter per annum, taking into consideration actual reads and attempted reads.

Meter reading costs would decrease as the number of smart units are installed, but the cost of reading an individual dumb meter will increase as meter readers have to travel further between reads. We compared equations used by MML and Frontier Economics and have applied the MML equation to consider this inefficiency; assuming that the cost of reading a meter during the rollout period is a function of non-smart meter density and the meter reading cost. MML state:

“We have captured this inefficiency in our model by assuming that the cost of reading a meter during the roll-out period is a function of non-smart meter density and the meter reading cost with 100% density. This relationship is given by the simple equation:

\[ c = \sqrt{\frac{M}{m}} \text{PRC} \]

Equation 1:

(where \( c \) is the cost of reading a meter, \( M \) is the initial number of legacy meters, \( m \) is the number of remaining meters and \( \text{PRC} \) is the cost of reading a meter when \( M=m \)).

We have constrained meter reading inefficiencies to be up to twice the meter reading cost for 100% density.”

**Call centre costs**

Call centre cost savings are a result of a reduction in billing enquiries and complaints. Smart meters will mean the end of estimated bills and therefore fewer people will phone call centres regarding estimated bills. As a result there will be a need for less back office billing staff to handle bill enquiries and disputes. We assume this cost saving to be about £2.20 a year per meter based on supplier estimates that inbound call volumes could fall by around 30% producing a 20% saving in call centre overheads. Other consultation responses have used similar cost assumptions for call centre cost savings.

**Debt management**

More accurate energy use information should help consumers better manage their energy expenditure, preventing large debts arising. In addition more sophisticated smart meter specifications (AMM capability) will allow suppliers to shift consumers on to pay as you go and other payment styles (without changing the meter) that will allow customers more flexibility and lower the number of debtor days existing with the quarterly credit tariff. The ability to remotely switch customers between pay as you go and credit meters is only available under AMM. Consultation responses used assumptions between £1.70 and £2.50 per meter. We think that the majority of this
saving could only be gained with an AMM specification meter (i.e. a meter that includes a valve to change the meter from credit to PPM). We propose that a fraction of the total benefit of better debt management should be applied to all smart meter specs (AMM and AMR) but the full amount should only be applied to AMM meters. Considering all the consultation suggestions we propose a debt management benefit of £0.50 for all smart meter technologies and an extra £1.70 benefit from having a meter with an AMM spec.

We also include a saving for suppliers from bad debt reduction, but this is a transfer from consumers to suppliers and is therefore not included as a benefit to society but is included in the distributional analysis as a benefit to suppliers.

**Theft**

The implementation of smart metering could reveal existing theft and allow suppliers to combat it better. Consultation responses have assumed that this could allow a reduction in theft of about 20-33% or £0.27 to £0.85 per meter per year. BERR assumes that the amount of theft is likely to decrease as suppliers will have access to much more accurate and frequent data and will detect theft more quickly, although people will always find new methods of defrauding smart meters. There is a discussion as to whether this is a transfer from consumers to suppliers (people having energy for free, and now paying for it) or if it is a benefit to society (suppliers cost savings from not having to investigate fraud). As a result we shall only consider marginal savings that will be passed onto society; a reduction of 10% or £0.20 per meter per year

**PPM cost to serve**

Smart meters should bring savings in the cost to serve for prepayment customers. These savings arise primarily from reduced maintenance and service needs. Ofgem estimated that the additional cost to serve for a dual fuel PPM customer is about £60-85 a year. Consultation responses assumed minimal PPM cost to serve savings as they suggested there would still be sufficient extra costs involved with PPM consumers (e.g. alternative payment methods (e.g. mobile top-up) would have higher commission than currently charged by the Post Office/ Paypoint). Energywatch on the other hand see large potential benefits from PPM cost to serve savings.

We will assume that there are PPM costs to serve savings from smart meters (although policy engagement maybe needed to ensure them). To be conservative we assume these annual savings to be £6 and £8 per electricity and gas PPM respectively (based on 20% savings on the costs to serve of £30 and £40 for electricity and gas meters). This saving is only possible for PPM meters

**Remote switching and disconnection**

There are additional benefits for the AMM specification that result from having the ability to remotely switch from credit to debit and also remotely disconnect electricity and gas meters. The direct benefits associated with these capabilities are the avoided site visits and equipment upgrade costs. We feel that the remote switching benefit has already been included in the debt handling benefit (for credit customers) and PPM cost to serve savings (for PPM customers) above. But we include a benefit of £0.50 per credit meter per year for benefits of being able to remotely disconnect customers, although policy action will be needed to ensure that suppliers do not take advantage of this function. (It is worth noting that currently the valve to do this costs about £5 for the gas meter.)
Supplier switching

We include a cost saving for the process of a consumer switching energy supplier. The introduction of smart metering should allow a rationalisation of the arrangements for handling a change of supplier, and as a result trouble shooting teams employed to sort out exceptions would no longer be needed. Suppliers will be able to take accurate readings on the day of changing supplier, so resolving the need to follow up any readings that do not match. We shall assume savings of £100m per year (possible additional systems costs are included in the IT and systems cost estimate).

Future energy products

We assumed a benefit of £120m per year that begins in 2020 from the expectation from suppliers of selling energy products as a result of smart metering. This is only a benefit to suppliers, not to society, as it is very unlikely that the profits from these products will be passed onto consumers.

Avoided special meter reads

We have included additional benefits to take into account the reduction in special reads currently needed and part of this is the likely reduction in safety checks, the majority of which are currently made at the same time as taking the reading. This benefit is £0.75 per credit meter per annum.

The scope of the inspection includes safety and tampering related requirements as well as gaining an actual meter reading. Whilst smart metering functionality may address some of those requirements we cannot see a reason (at present) for the safety and tampering checks not to be needed with smart meters as well as basic meters. Additionally, the relevant regulators will need to be convinced that the relevant standards concerning safety and revenue protection are maintained before the licence conditions could be changed.

Table 2: Comparison of selected benefits attributed to AMR or AMM functionality

<table>
<thead>
<tr>
<th></th>
<th>AMR</th>
<th>AMM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meter reading</td>
<td>£5 per credit meter per year</td>
<td>£5 per credit meter per year</td>
</tr>
<tr>
<td>Call centre costs</td>
<td>£2.20 per meter per year</td>
<td>£2.20 per meter per year</td>
</tr>
<tr>
<td>Debt management</td>
<td>£0.5 per credit meter per year</td>
<td>£2.2 per credit meter per year</td>
</tr>
<tr>
<td>Theft</td>
<td>£0.2 per meter per year</td>
<td>£0.2 per meter per year</td>
</tr>
<tr>
<td>PPM cost to serve</td>
<td></td>
<td>£6 &amp; £8 for elec and gas PPM</td>
</tr>
<tr>
<td>Remote disconnect</td>
<td></td>
<td>£0.5 per credit meter per year</td>
</tr>
<tr>
<td>Supplier switching</td>
<td>£100m per year</td>
<td>£100m per year</td>
</tr>
</tbody>
</table>

It is noted that further work is required to attribute benefits to functionality.

Intangible benefits

It has been possible to make a quantitative assessment of the benefits described above within the modelling for this Impact Assessment. However there is also another subset of benefits which may – especially in the medium to longer term – be attributable to smart metering and have an impact on the overall analysis. At the current time it has not been possible to quantitatively assess these benefits either

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12 Based on estimates by Owen and Ward
because it was not possible to gather sufficient evidence of the likely scale of the benefit or because these might be termed “facilitated benefits” where the existence of smart metering will facilitate the uptake or management of new services or approaches to energy supply.

**Competition**

It has been argued that the introduction of smart meters will have an effect on the competitive pressure within energy supply markets – in particular because accurate and reliable data flows may make the switching process easier and encourage consumers to seek out better deals, thereby driving prices down. In addition the availability of accurate and timely information should create opportunities for energy services companies to enter the domestic and smaller business markets; and for other services to be developed, for example in security or healthcare. Overall smart meters should enhance the operation of the competitive market by improving performance and the customer experience, encouraging suppliers’ innovation and customer participation.

**Longer term network management and demand-side load shifting**

In the longer term more sophisticated approaches to management of the energy networks may be possible and the possibility of remote management (either by suppliers or consumers) becomes real. It is difficult to quantify what the benefits of these changes would be or the other opportunities which may flow from them. Smart metering could facilitate responses to future changes in energy demand (through, for example a greater take up of electric cars) which may require more proactive management and pricing.

In addition smart meters may enable more effective management of the future grid where energy will come from a variety of sources – including some which may be more intermittent – and generation becomes more decentralised. There are potential benefits here from reduced overall demand and the smoothing of demand between peaks. In the longer term benefits may also be identified in this area which may contribute on security of supply objectives.

**Supplier Obligation**

Policy development in this area continues, but it has been argued that in order to achieve potentially challenging targets – where absolute reductions in household carbon may be required – the functionality of AMM specified smart meters would be necessary. Smart metering will provide the information that is required to facilitate the achievement of these targets. Smart metering, by giving suppliers better information about household energy use, could also facilitate targeting of fuel poverty resources.

**Renewables targets**

With additional renewable electricity being delivered predominantly by wind generation back-up generation is required to maintain security of supply. Smart metering with automated controls to switch load would reduce the need to bring on-line conventional generation and reduce the need for investment in backup generation.

Some aspects of intangible benefits identified will be the subject of further work.

### 3. Speed of roll out

**New and replacement**: Each year approximately 4% of the gas and electricity meter stock is replaced as meters come to the end of their operational life or breakdown and as new connections are made. This cycle would continue – regardless of a
government mandate for smart metering – and over a ~20 year period it would be expected that the entire meter stock would be refreshed. With a government mandate for new and replacement it could take up to 20 years to achieve a full roll-out of smart meters; stranding costs would be eliminated but the full benefits would take this length of time to come on stream. Because only 4% of meters would be replaced each year the potential for suppliers to learn from the process and limit ongoing mistakes is greater and the risk to consumers is therefore less. The arguments for making a significant market change are less strong.

In practice it is likely that a “tipping point” would be reached before 20 years where the cost of maintaining the remaining stock of non-smart meters would outweigh the cost of installing smart meters even where the old meter did not require replacement. Suppliers would need to run dual systems for a longer period than under an accelerated roll-out and it would be more difficult to deliver a dual-fuel solution, which may lead to separate gas and electricity communications systems without regulatory intervention or industry agreements.

We have assumed that this tipping point does not occur and new and replacement smart meter roll out takes 20 years for all homes to have a smart meter.

**A ten-year roll-out:** would bring the benefits of smart metering on line more quickly and a more intensive approach would provide greater benefits of scope and scale. The necessity to run dual administration systems would be reduced and there would be some flexibility in the timescales i.e. a slower start (with trials etc.) leading to a much faster period of actual roll-out.

However there would be inevitable stranding costs and potentially higher capital costs and it would be necessary to acquire the equipment, competent labour and meters within a compressed period. Additionally the scope to adjust delivery and learn from mistakes is less – the time available to adjust being much shorter. There is potential for greater risk to consumers in terms of cost. Arguments for making changes to the market to deliver the smart meter mandate may be considered stronger with an accelerated roll-out.

4. **Communications Options**

Given the uncertainties around communications design and costs, the Government is ultimately likely to leave the decision on which communications option to use to suppliers/ the market to decide; it is likely that further work would be required to ensure interoperability or standards. The communication option used in the IA is only one of many possible options and cheaper or more expensive options may be used by suppliers/ the industry.

We assume that gas meters piggy-back on the electricity meter for the communications option. This means that the gas meter ‘talks’ to the electricity meter and sends data through the communication device in the electricity meter to a data centre or the supplier. We assume that the device needed by the meters to ‘talk’ to each other costs £1 for the electricity meter and £3 for the gas meter (which will have to be battery powered). We will represent the cost difference if gas meters are not able to piggy back on the electricity meter’s external communications.

In the IA we calculate the communications devices as separate to the meter specifications. However, in reality we assume that to a large extent the communication devices would be built into the meter specification for AMR and AMM meters. Calculating the costs in this way should not compromise our analysis.

The majority of consultation responses made simple assumptions for their communications options with the exception of MML who analysed a number of communication options, some more current, some less proven in the market. We
decided to focus on two of MML’s scenarios and one further option that MML did not consider. These scenarios are:

- a hybrid of piggyback broadband and 3G technology (similar to SMS). This option is at the cheaper end of the ‘communication scale’ and takes advantage of existing communications networks;
- a self contained national radio network, assumed to be a medium level scenario
- hybrid of Power Line carrier and Wimax technology

Within the IA we use only the first option, but will discuss the other options and demonstrate what difference it would make to the overall NPV.

The hybrid options take account of the fact that it is not possible to select one technology that will work and be economically viable in all locations. The costs of different options vary and there are multiple trade-offs to be made. It is unlikely that there is a ‘one size’ fits all approach. To account for this the hybrid options assume that Broadband/PLC and 3G/wimax are distributed 75% and 25% respectively to cover the realistic prospect of different technologies being appropriate for either urban or rural areas respectively.

The second option we considered is based on the idea of installing a national radio network infrastructure available to all suppliers (a cheaper alternative to a Power Line Carrier). This option could provide a high rate of data transfer and would be a universal, national solution.

Further information on the different communications options and detailed costs can be found in Annex 3.

<table>
<thead>
<tr>
<th>Table 3: Net Present Value cost estimates for three communications options</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total costs</strong></td>
</tr>
<tr>
<td>Hybrid 2</td>
</tr>
<tr>
<td>National radio Network</td>
</tr>
<tr>
<td>Hybrid 1</td>
</tr>
<tr>
<td>If no piggy backing with Hybrid 2</td>
</tr>
</tbody>
</table>

5. Other key assumptions

*Installation*

Installation costs are likely to vary depending upon the method of delivery and the period of the roll-out, installation costs are likely to be lower if a systematic managed roll-out programme is employed, but up front costs maybe greater. After considering the assumptions from consultation responses we will use the following:

*Table 4: Comparison of installation costs £*

<table>
<thead>
<tr>
<th></th>
<th>Electricity</th>
<th>Electricity PPM</th>
<th>Gas</th>
<th>Gas PPM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dumb Meter+Smart Box</td>
<td>10.0</td>
<td>0.0</td>
<td>40.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Basic meter</td>
<td>20.0</td>
<td>30.0</td>
<td>40.0</td>
<td>50.0</td>
</tr>
<tr>
<td>AMR Spec</td>
<td>24.0</td>
<td>34.0</td>
<td>44.0</td>
<td>54.0</td>
</tr>
<tr>
<td>AMM Min Spec</td>
<td>29.0</td>
<td>29.0</td>
<td>49.0</td>
<td>49.0</td>
</tr>
</tbody>
</table>

We have also included variations depending on the rollout option. The RFM will have dual fuel rollout savings £10 off gas meters, whilst the other options will not. We

---

13 This is just duel fuel installation savings – we still assume gas meters will piggy back on electric meters for external comms in all the scenarios.
have assumed that the new and replacement option will face a lower risk associated with installation charges than the faster rollout options.

Maintenance
Smart meter maintenance costs are widely uncertain, because an integrated solution with a communications network has never been tried in the UK. Ofgem (2006) assumed annual maintenance costs for smart meters to be 2.5% of the meters purchase cost. This assumption is used in a few consultation responses, and seems reasonable.

IT costs
New IT systems for data management, settlement and storage are likely to be needed before the rollout start. Discussions with suppliers suggest that there would be a one off cost of around £12m for the new IT system and an additional annual cost of £1m for operation and maintenance. Other responses range from £5m to £25m for one off IT systems costs, and this generally changes depending on the rollout option.

Legal, institutional and planning costs
This is an investment to implement policy and adapt the current systems. Consultation estimates vary, ranging up to £900m for the RFM. Few consultation responses have included both these systems costs and the IT costs above. We will assume legal, institutional and planning costs of £100m for new and replacement rollout, £200m for 10 year market rollout and £500m for the RFM.

Energy use of equipment
We have considered the extra energy needed to run the smart technology including the RTD and communications devices. Few of the consultation responses have considered this issue. We have held discussions with meter specialists and they suggest that the additional smart equipment costs could be 1.25w/h for the meter including communications and 0.6w/h for the RTD.

We will only consider this extra energy usage for electricity meters (as anything attached to the gas meter will be run on batteries) and we will consider different energy usage for different meter specifications. As a result, we propose using 0.6 and 1 watt per hour for the RTD and communications for the electricity device and suggest that the smart box and an AMR meter use 0.5 watts per hour (more than a basic meter) whilst the AMM spec meter uses 1 watt per hour more.

Stranding
Stranding costs are the costs incurred when a meter is taken out before the end of its expected life time. This cost is dependent on the speed of the roll-out option; it would be avoided in a new and replacement scenario, but would be considerable for a 10 year roll-out option (the basic meter life span is 20 years). We will use MML’s estimates for stranding.

Administration Burden

---

14Note that a dual fuel roll out would be preferred by most participants as it is cheaper and on those grounds some are already assuming that a solution can be found in a market roll out. Also note that about a third of customers are on duel fuel, so suppliers could already roll out duel fuel solutions in a market environment to a third of customers. Most customers switch to duel fuel tariffs, so this figure is growing. This has not been taken into consideration in the model.
In looking at the installation costs of a managed programme of smart meters, we sought information from suppliers on the costs of notifying customers of the need to install new meters. We now believe that these costs will amount to £6m per annum as opposed to £31m as in the PwC administrative burdens measurement exercise.

**Roll-out options**

The roll out options considered are linked to the policy options. We have considered the qualitative differences between different policy options (annex 1) and have mentioned quantitative differences for the appropriate assumptions. The main differences between the rollouts are the length of the rollout and the amount of central involvement. The additional assumed differences between the options were:

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installation costs</td>
<td>Lower risk for new and replacement approaches</td>
</tr>
<tr>
<td>Legal costs</td>
<td>N&amp;R – £100m, Market - £200m, RFM – 500m</td>
</tr>
<tr>
<td>Dual Fuel</td>
<td>Only for the RFM</td>
</tr>
</tbody>
</table>

6. **Small Businesses**

The economic modelling used here was developed for the domestic sector and includes micro businesses where the consumption levels are similar. We have extended the work to begin to explore the potential of smart metering for the small business sector which we estimate covers approximately 2,170,000 electricity meters and 380,000 gas meters. It is noted that the range of benefits and costs to small businesses are likely to be different from those assessed for the domestic sector. The analysis here is not exhaustive and further work is required on the assumptions used and particular issues that need to be captured for this sector.

In this initial assessment the economic model has been run to reflect higher annual demand from this sector of 170,000kWh for gas and 18,000kWh for electricity (more than five times domestic demand). Small businesses will also have different tariffs as a result of consuming more and we assume that this is between the domestic tariff and the overall average commercial tariff; 2.03pence for gas and 7.55pence for electricity.\(^{15}\) We also consider the number of new small businesses created each year, for which we assume a 2% increase per annum. We consider energy savings of 2% for both gas and electricity use and we run sensitivities around this of 0.5% and 3.5%.

7. **Results**

*Comparison of results across the options analysed*

The results below are produced by running a model with the above assumptions. Within the model the up front costs are annuitised over either the life time of the meter/device or the 20 year period. To account for risk and potential over/under estimates of costs and benefits we have added optimism bias to some of the up front costs, and applied sensitivity analysis to a range of benefits. No sensitivity analysis

\(^{15}\) Based on Dukes
has been included for costs, but this has been covered by the optimism bias (see risk section below).

Table 6: Comparison of total costs across options analysed £bn

<table>
<thead>
<tr>
<th>Total costs (£bn)</th>
<th>Option 1</th>
<th>Option 2a</th>
<th>Option 2b</th>
<th>Option 2c</th>
<th>Option 2d</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No domestic smart metering mandate but a better billing and displays policy</td>
<td>Mandated 10-year roll out of AMM specification smart meters within existing market structures</td>
<td>Mandated 10-year roll out of AMR specification smart meters within existing market structures</td>
<td>Mandated 10-year roll out of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>Mandated new and replacement roll out of AMM specification smart meters within existing market structures</td>
<td>Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model</td>
</tr>
<tr>
<td></td>
<td>0.768</td>
<td>13.4</td>
<td>10.5</td>
<td>9.6</td>
<td>8.0</td>
<td>12.7</td>
</tr>
</tbody>
</table>

We have run one communications choice (hybrid 2) for all of the options, but it should be noted that the final decision on which communications choice is used will be down to the industry and may not be the one used in the IA. The hybrid 2 communications option makes up about 20% of the total costs. If a different communications option was used then the cost could be increased. For example:

- Using a national radio network will result in greater costs of about £0.4bn to society for all the options.
- The hybrid 1 option would result in greater costs of £3.0bn to society for all options.

It is possible that these different communications options maybe chosen by the industry (as well as a variety of other options not discussed in the IA) and as a result the overall NPV for society will change by the above amounts.

Table 7: Comparison of total benefits across options analysed £bn

<table>
<thead>
<tr>
<th>Total benefits (£bn)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>0.6</td>
<td>1.3</td>
<td>1.9</td>
</tr>
<tr>
<td>Mandated 10-year roll out of AMM specification smart meters within existing market structures</td>
<td>8.9</td>
<td>12.0</td>
<td>15.1</td>
</tr>
<tr>
<td>Mandated 10-year roll out of AMR specification smart meters within existing market structures</td>
<td>7.2</td>
<td>9.6</td>
<td>11.9</td>
</tr>
<tr>
<td>Mandated 10-year roll out of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>7.2</td>
<td>9.6</td>
<td>11.9</td>
</tr>
<tr>
<td>Mandated new and replacement roll out of AMM specification smart meters within existing market structures</td>
<td>5.0</td>
<td>6.8</td>
<td>8.5</td>
</tr>
<tr>
<td>Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model</td>
<td>8.6</td>
<td>11.7</td>
<td>14.6</td>
</tr>
</tbody>
</table>

Table 8: Comparison of supplier Net Present Values across options analysed £bn

<p>| Supplier Net Present Value (£bn) | 100% cost pass |</p>
<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>No domestic smart metering mandate but a better billing and displays policy</td>
<td>0.2</td>
<td>0.03</td>
<td>-0.1</td>
</tr>
<tr>
<td>Option 2a</td>
<td>Mandated 10-year roll out of AMM specification smart meters within existing market structures</td>
<td>1.4</td>
<td>1.1</td>
<td>0.7</td>
</tr>
<tr>
<td>Option 2b</td>
<td>Mandated 10-year roll out of AMR specification smart meters within existing market structures</td>
<td>1.2</td>
<td>0.8</td>
<td>0.5</td>
</tr>
<tr>
<td>Option 2c</td>
<td>Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>1.2</td>
<td>0.8</td>
<td>0.5</td>
</tr>
<tr>
<td>Option 2d</td>
<td>Mandated new and replacement roll out of AMM specification smart meters within existing market structures</td>
<td>1.1</td>
<td>0.9</td>
<td>0.7</td>
</tr>
<tr>
<td>Option 3</td>
<td>Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model</td>
<td>1.4</td>
<td>1.0</td>
<td>0.7</td>
</tr>
</tbody>
</table>

Table 9: Comparison of customer Net Present Values across options analysed £bn

<table>
<thead>
<tr>
<th>Customer Net Present Value (£bn)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>-1.2</td>
<td>-0.5</td>
<td>0.2</td>
</tr>
<tr>
<td>Option 2a</td>
<td>-5.6</td>
<td>-3.0</td>
<td>-0.3</td>
</tr>
<tr>
<td>Option 2b</td>
<td>-4.0</td>
<td>-1.7</td>
<td>0.8</td>
</tr>
<tr>
<td>Option 2c</td>
<td>-2.6</td>
<td>-0.4</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 2d</td>
<td>-2.9</td>
<td>-1.6</td>
<td>-0.2</td>
</tr>
<tr>
<td>Option 3</td>
<td>-6.5</td>
<td>-5</td>
<td>-1.3</td>
</tr>
</tbody>
</table>

Table 10: Impact per account – average annual impact per meter £

<table>
<thead>
<tr>
<th>Impact per account: Average annual impact per meter (£)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>-1.48</td>
<td>-0.42</td>
<td>0.63</td>
</tr>
<tr>
<td>Option 2a</td>
<td>-7.14</td>
<td>-3.42</td>
<td>0.43</td>
</tr>
<tr>
<td>Option 2b</td>
<td>-4.96</td>
<td>-1.57</td>
<td>1.96</td>
</tr>
<tr>
<td>Option 2c</td>
<td>-3.01</td>
<td>0.15</td>
<td>3.86</td>
</tr>
<tr>
<td>Option 2d</td>
<td>-3.49</td>
<td>-1.53</td>
<td>0.52</td>
</tr>
<tr>
<td>Option 3</td>
<td>-8.14</td>
<td>-4.48</td>
<td>-0.70</td>
</tr>
</tbody>
</table>
It should be noted that the figures presented in Table 10 are per meter rather than per customer, therefore the majority of customers with a gas and an electricity meter will face double the annual cost shown over 20 years.

### Table 11: Comparison of final Net Present Values across options analysed £bn

<table>
<thead>
<tr>
<th>Final Net Present Value (£bn)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>-0.13</td>
<td>0.5</td>
<td>1.1</td>
</tr>
<tr>
<td>Option 2a</td>
<td>-4.4</td>
<td>-1.3</td>
<td>1.6</td>
</tr>
<tr>
<td>Option 2b</td>
<td>-3.2</td>
<td>-0.9</td>
<td>1.3</td>
</tr>
<tr>
<td>Option 2c</td>
<td>-2.1</td>
<td>0</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 2d</td>
<td>-2.8</td>
<td>-1.2</td>
<td>0.3</td>
</tr>
<tr>
<td>Option 3</td>
<td>-4.0</td>
<td>-1.0</td>
<td>1.9</td>
</tr>
</tbody>
</table>

### Table 12: Carbon savings and cost effectiveness

<table>
<thead>
<tr>
<th>Carbon savings (£)</th>
<th>Cost effectiveness (£/tCO2)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
</tr>
<tr>
<td>Option 1</td>
<td>60</td>
</tr>
<tr>
<td>Option 2a</td>
<td>104</td>
</tr>
<tr>
<td>Option 2b</td>
<td>104</td>
</tr>
<tr>
<td>Option 2c</td>
<td>104</td>
</tr>
<tr>
<td>Option 2d</td>
<td>64</td>
</tr>
<tr>
<td>Option 3</td>
<td>102</td>
</tr>
</tbody>
</table>

As mentioned in the benefits section the carbon savings are only for gas as the electricity carbon savings are already considered by the EU ETS. This does not apply for option 1 as the display policy was taken into account when setting the EU ETS cap.

*Indicative Results for small businesses*

### Table 13: Additional assumptions used in the indicative analysis for small business

<table>
<thead>
<tr>
<th></th>
<th>Electricity</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meters</td>
<td>2,170,000</td>
<td>380,000</td>
</tr>
<tr>
<td>Consumption (KWh)</td>
<td>18,000</td>
<td>170,000</td>
</tr>
<tr>
<td>Tariff (p/kWh)</td>
<td>7.55</td>
<td>2.03</td>
</tr>
<tr>
<td>New meters</td>
<td>2% - 51,000 per annum</td>
<td></td>
</tr>
<tr>
<td>Energy savings</td>
<td>2% (low 0.5%, high 3.5%)</td>
<td>2% (low 0.5%, high 3.5%)</td>
</tr>
</tbody>
</table>

These initial results presented below indicate a positive case for the rollout of smart meters for small businesses. However, as has been noted previously, this is a very early analysis and further work to refine the assumptions used and identify particular issues relating to the small business sector is required.
### Table 14: Indicative Final Net Present Values for Small Businesses Roll Outs £bn

<table>
<thead>
<tr>
<th>Small Businesses: Final Net Present Value (£bn)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 2a: Mandated 10-year roll out of AMM specification Smart meters within existing market structures</td>
<td>0.9</td>
<td>1.6</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 2b: Mandated 10-year roll out of AMR specification Smart meters within existing market structures</td>
<td>1.0</td>
<td>1.6</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 2c: Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>1.0</td>
<td>1.6</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 2d: Mandated new and replacement roll out of AMM specification Smart meters within existing market structures</td>
<td>0.5</td>
<td>1.0</td>
<td>1.4</td>
</tr>
<tr>
<td>Option 3: Mandated 10-year roll out of AMM specification Smart meters in a regional franchise market model</td>
<td>0.5</td>
<td>1.1</td>
<td>1.7</td>
</tr>
</tbody>
</table>

### Table 15: Indicative Total Costs for Small Business Roll Outs £bn

<table>
<thead>
<tr>
<th>Small Businesses: Total costs (£bn)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 2a: Mandated 10-year roll out of AMM specification Smart meters within existing market structures</td>
<td>1.2</td>
</tr>
<tr>
<td>Option 2b: Mandated 10-year roll out of AMR specification Smart meters within existing market structures</td>
<td>1.0</td>
</tr>
<tr>
<td>Option 2c: Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>1.0</td>
</tr>
<tr>
<td>Option 2d: Mandated new and replacement roll out of AMM specification Smart meters within existing market structures</td>
<td>0.8</td>
</tr>
<tr>
<td>Option 3: Mandated 10-year roll out of AMM specification Smart meters in a regional franchise market model</td>
<td>1.5</td>
</tr>
</tbody>
</table>

### Table 16: Indicative Total Benefits for Small Business Roll Outs £bn

<table>
<thead>
<tr>
<th>Small Businesses: Total benefits (£bn)</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 2a: Mandated 10-year roll out of AMM specification Smart meters within existing market structures</td>
<td>2.0</td>
<td>2.8</td>
<td>3.4</td>
</tr>
<tr>
<td>Option 2b: Mandated 10-year roll out of AMR specification Smart meters within existing market structures</td>
<td>1.9</td>
<td>2.6</td>
<td>3.2</td>
</tr>
<tr>
<td>Option 2c: Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>1.9</td>
<td>2.6</td>
<td>3.2</td>
</tr>
<tr>
<td>Option 2d: Mandated new and replacement roll out of AMM specification Smart meters within existing market structures</td>
<td>1.3</td>
<td>1.8</td>
<td>2.2</td>
</tr>
<tr>
<td>Option 3: Mandated 10-year roll out of AMM specification Smart meters in a regional franchise market model</td>
<td>2.0</td>
<td>2.7</td>
<td>3.3</td>
</tr>
</tbody>
</table>

### Table 17: Indicative Impacts per Account for Small Business Roll Outs £
<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
<th>Low</th>
<th>Med</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 2a</td>
<td>Mandated 10-year roll out of AMM specification smart meters within existing market structures</td>
<td>-4.58</td>
<td>9.75</td>
<td>23.76</td>
</tr>
<tr>
<td>Option 2b</td>
<td>Mandated 10-year roll out of AMR specification smart meters within existing market structures</td>
<td>-0.65</td>
<td>13.68</td>
<td>27.69</td>
</tr>
<tr>
<td>Option 2c</td>
<td>Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures</td>
<td>22.42</td>
<td>37.61</td>
<td>55.07</td>
</tr>
<tr>
<td>Option 2d</td>
<td>Mandated new and replacement roll out of AMM specification smart meters within existing market structures</td>
<td>13.03</td>
<td>22.22</td>
<td>31.35</td>
</tr>
<tr>
<td>Option 3</td>
<td>Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model</td>
<td>-38.63</td>
<td>-24.66</td>
<td>-10.99</td>
</tr>
</tbody>
</table>

It should be noted that the figures presented in Table 16 are per meter rather than per customer, therefore the majority of customers with a gas and an electricity meter will face double the annual cost shown over 20 years.

Table 18: Carbon savings and Cost effectiveness

<table>
<thead>
<tr>
<th></th>
<th>Carbon Savings (£)</th>
<th>Cost Effectiveness (£/tCO2)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>Med</td>
</tr>
<tr>
<td>Option 2a</td>
<td>25</td>
<td>110</td>
</tr>
<tr>
<td>Option 2b</td>
<td>25</td>
<td>110</td>
</tr>
<tr>
<td>Option 2c</td>
<td>25</td>
<td>110</td>
</tr>
<tr>
<td>Option 2d</td>
<td>16</td>
<td>72</td>
</tr>
<tr>
<td>Option 3</td>
<td>24</td>
<td>184</td>
</tr>
</tbody>
</table>

As stated in the benefits section the carbon savings are only for gas as the electricity carbon savings are already considered by the EU ETS.

As already noted above these are indicative results and this is identified as an area for more detailed specific work.

8. Benchmarking

As discussed in Section D Option 1 represents a baseline case, where there is no smart metering roll out, it includes:
- The costs of the continued installation of basic meters
- Benefits from better billing
- Benefits from policies on new, replacement and on request RTDs

For the options 2a-d and 3, where a smart metering roll out takes place, a counterfactual has been used which:
- Removes the costs of the continued installation of basic meters
- Includes benefits from better billing and display policies.

We did not consider the 20 to 30% of the market to which suppliers might roll out smart meters without a government mandate. The reason for this is that issues around interoperability would need to be resolved before this could be done effectively in the market.

The cost of the continued basic meter installation is deducted from the costs for the AMM and AMR specification. This is not the case for smart boxes where we assume a basic meter is still required as the smart box is linked up to basic meters (except for
half of the gas meters). This cost is deducted from the asset and installation costs of each option.

The benefits from better billing and displays policies result in a reduction in benefits for smart meters; these benefits are subtracted from the overall benefits for smart meters.

F. Risks

Risk Mitigation and Optimism Bias
The roll out of Smart Meters entails risks regarding costs, benefits and duration of roll-out. HMT’s Green Book Guidelines require that a risk analysis is carried out to address potential optimism bias in estimated costs.

Stakeholders do not explicitly make allowance for optimism bias in their estimates, provided to BERR or to independent researchers. It has been argued that by calling for pre-tender quotes for various pieces of equipment, suppliers are revealing the likely costs of the elements of smart metering; hence no further adjustment is necessary. However, major infrastructure and IT contracts are often affected by over optimism, so ignoring the Government guidelines would be difficult to justify.

Based on Green book guidance we have considered an upper range value for optimism bias of 150% and a lower range value of 10%. A risk mitigation factor is applied for each of the identified risks, ranging from 0 (where no mitigation plan exists) to 1 (where risks are fully managed). The relationship between the risk mitigation factor and optimism bias is given by:

\[
OB = (1 - RMF) \times U
\]

(where \(OB\) is the estimated optimistic bias, \(RMF\) is the risk mitigation factor for this area and \(U\) is the upper limit for biases). When a technology receives \(RMF = 1\), then the appropriate level of \(OB\) is the lower range. Existing technologies, like the clip-on, do not entail capex risks and hence they receive the lowest bias correction. Dumb and Smart receives the largest bias correction, because there is no single specification and operational framework for this technology.

In terms of communications technologies, there is no operational framework for any of the options. Hence, even the proven technologies have a relatively high risk mitigation factor and \(OB\). Future technologies are ranked as bearing double the amount of risk than proven technologies. This might not be entirely true, given the incredible speed by which innovation is progressing in the communications industry, however, given the lack of further data, we have opted for doubling the risk factors.

The adjustments are smaller where a more sophisticated risk mitigation approach is in place; however, the adjustments are large and add a sizeable element to the total estimated costs of smart meter roll out. Around £3 to £4 billion is added to cost estimates provided by stakeholders as a result of the application of these factors.

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16 http://www.hm-treasury.gov.uk/economic_data_and_tools/greenbook/data_greenbook_guidance.cfm
17 It is worth noting that the optimism bias estimates suggested by the Green Book are based on research into construction projects. To get a full understanding of the optimism bias that should be applied to this project we would have to investigate the history of similar programmes and policies, comparing the estimated costs with the final costs.
Table 19: Optimism bias on Technology capex (includes installation)

<table>
<thead>
<tr>
<th>Risk Mitigation Factor</th>
<th>Upper</th>
<th>Lower</th>
<th>OB Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMM</td>
<td>0.7</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>AMR</td>
<td>0.7</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>Dumb+Smart</td>
<td>0.3</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>Clip-on</td>
<td>1.0</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>RTD</td>
<td>0.9</td>
<td>150%</td>
<td>10%</td>
</tr>
</tbody>
</table>

Communications

<table>
<thead>
<tr>
<th>Risk</th>
<th>Upper</th>
<th>Lower</th>
<th>OB Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Radio</td>
<td>0.6</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>Hybrid 1</td>
<td>0.6</td>
<td>150%</td>
<td>10%</td>
</tr>
<tr>
<td>Hybrid 2</td>
<td>0.8</td>
<td>150%</td>
<td>10%</td>
</tr>
</tbody>
</table>

IT

<table>
<thead>
<tr>
<th>IT and Settlement System (capex)</th>
<th>Upper</th>
<th>Lower</th>
<th>OB Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.1</td>
<td>150%</td>
<td>10%</td>
</tr>
</tbody>
</table>

It is accepted by BERR that the optimism bias applied above is quite a blunt tool, but with further work we would like to refine the application of the bias and further investigate risk mitigation options. We feel that the above optimism bias includes the following risks:

- Asset costs
- Maintenance costs
- Asset life as a result of the combination of communications and meter technology
- Government risk
- Installation costs
- Labour cost overruns
- Customer resistance
- Communications costs and life
- IT costs and life

Adjustments for capital and installation costs (for the meters and communications) have been included in the modelled results shown elsewhere in this report; however, no adjustment of duration estimates is made, i.e. for roll out periods. These are expected to be attained and not over run. An incentive/penalty regime may be required to ensure that the roll out targets are hit at reasonable cost. That may be the subject of a further impact assessment.

More detail on optimism bias and how it is applied can be found on the Treasury website in the Green Book guidance18.

No adjustment in respect of benefits is proposed – instead sensitivity analysis has been applied to the main elements of the benefits. No sensitivity analysis was made for costs as it was felt that the risks for costs were covered by the optimism bias. We ran the following sensitivities on the benefits:

Table 20: Sensitivities on benefits

<table>
<thead>
<tr>
<th></th>
<th>high benefits</th>
<th>med</th>
<th>low benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy savings electricity</td>
<td>4%</td>
<td>2.8%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Energy savings gas</td>
<td>3%</td>
<td>2%</td>
<td>1%</td>
</tr>
<tr>
<td>Energy savings gas PPM</td>
<td>1%</td>
<td>0.5%</td>
<td>0.25%</td>
</tr>
</tbody>
</table>

18 [link](http://www.hm-treasury.gov.uk/economic_data_and_tools/greenbook/data_greenbook_supguidance.cfm#optimism)
Shadow price of carbon savings

<table>
<thead>
<tr>
<th></th>
<th>£30.6</th>
<th>£25.50</th>
<th>£22.95</th>
</tr>
</thead>
</table>

Supplier benefits:

<table>
<thead>
<tr>
<th></th>
<th>Call centre costs</th>
<th>£2.42</th>
<th>£2.20</th>
<th>£1.98</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Meter reading</th>
<th>£6.50</th>
<th>£6.00</th>
<th>£5.50</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Theft</th>
<th>15%</th>
<th>10%</th>
<th>5%</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th></th>
<th>TOU take up</th>
<th>40%</th>
<th>20%</th>
<th>0%</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th></th>
<th>PPM Cost of Serve</th>
<th>30%</th>
<th>20%</th>
<th>10%</th>
</tr>
</thead>
</table>

It is worth noting that the energy savings and shadow price of carbon affect the total cost for each option due to the energy use by the devices, but the effect is minimal.

Table 21: Option specific risks £bn

<table>
<thead>
<tr>
<th>£bn</th>
<th>Optimism Bias affect</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMM – RFM</td>
<td>3.060</td>
</tr>
<tr>
<td>AMM – market</td>
<td>3.321</td>
</tr>
<tr>
<td>AMR - market</td>
<td>2.565</td>
</tr>
<tr>
<td>Smart box - market</td>
<td>2.975</td>
</tr>
</tbody>
</table>

G. Enforcement

All of the options outlined in this impact assessment would be implemented via changes to suppliers’ licence obligations. New licence requirements would be enforced in the same manner as existing licence obligations – by Ofgem as the gas and electricity markets regulator.

Ofgem has powers under the Gas Act 1986 and the Electricity Act 1989 to take enforcement action including imposing financial penalties for breaches of requirements imposed under or pursuant to those Acts. Under the Competition Act 1998, Ofgem has concurrent powers with the OFT to bring an end to anti-competitive behaviour as well as impose financial penalties on licence holders of up to 10% of their turnover.

Ofgem investigates any company which is found to be breaching the terms of their licence, acting anti-competitively, or breaching consumer protection law via a formal investigation. Investigations can be undertaken on Ofgem’s own initiative or on the receipt of complaints or on referrals from other regulatory bodies.

H. Recommendation – Next Steps

This is a consultation impact assessment. Given the breadth and complexity of the issues further work will now be undertaken to refine the analysis.

To this end, work will continue in the next few months to further refine the impact assessment related to both smart for domestic and for small business. In particular we intend to focus on the following areas which have been identified in consultation with stakeholders as requiring further in-depth analysis:

- treatment of risk within the economic analysis;
- assessment of market structures;
- attribution of benefits to technology functionality;
- communications options and structures; and
- further work on smart metering for small businesses.
Further discussions with stakeholders on the consultation impact assessment and in the areas identified above will take place over the next few months to further refine the impact assessment and define the policy options moving forward.

The next stage of the process will focus particularly on the risks and benefits of roll out models for smart metering which will run until the autumn.

Given the need to undertake further impact assessment work, and to take into account the initial results from the Energy Demand Research Project (EDRP), the Government intends to confirm its decisions on the way forward for smart metering for small businesses and for domestic consumers as soon as possible after the second report from the EDRP project in November 2008.

The overall aim of the process outlined above is to have completed all the necessary preparatory work to enable decisions to be taken in line with this timetable, including, if appropriate, on the central elements of a Government mandate. A meeting with stakeholders will be held on 1 May to discuss the process going forward in more detail.

I. Implementation
   This section will be populated when final approach is selected.

J. Monitoring and Evaluation
   This section will be populated when final approach is selected. However we anticipate that in the event of a roll out of smart metering for small businesses and/or domestic consumers, the regulator would monitor the roll out process. The policy would be reviewed once the rollout of smart meters had been completed and a medium term review undertaken within 5 years of roll out start.
Specific Impact Tests - Checklist

<table>
<thead>
<tr>
<th>Type of testing undertaken</th>
<th>Results in Evidence Base? (Y/N)</th>
<th>Results annexed? (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competition Assessment</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Small Firms Impact Test</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Legal Aid</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Sustainable Development</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Carbon Assessment</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Other Environment</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Health</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Race Equality</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Disability Equality</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Gender Equality</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Human Rights</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Rural Proofing</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>

**Competition assessment**

Great Britain would be the market affected. The products and services directly affected by the proposals would be gas and electricity supply, meter manufacture, market ownership, provision and maintenance, other metering support services and telecommunications between the customer and the manager of the meter data. The provision of energy services and wider smart home services could also be affected. The proposals would therefore affect gas and electricity suppliers, meter owners and operators and providers of ancillary services, telecommunications companies and providers of energy services and wider smart home services.

The proposals would not involve the payment of state aid or of subsidies.

The Government has considered a range of options for the roll-out of smart meters. The impacts of these options on the operation of the competitive market in metering vary. Many of the competition issues are addressed in the qualitative analysis of the options at Annex 1, but a brief summary is given here.

An approach under which suppliers delivered smart metering under the existing, competitive market model, would not adversely affect competition. Under this option suppliers would, as now, individually contract with various suppliers of meter assets and services, as well as with the providers of new communications services. It is possible that suppliers might wish to achieve a degree of brokered co-operation on installation within this option. While this could be beneficial in terms of cost, it might have an effect on competition and would require careful consideration of any likely, possible or unintended effects. Ofgem would need to have oversight of any such
arrangements, with regulatory action on this point being triggered by a complaint or other information coming to its attention.

One issue that might arise under a faster roll-out period would be that smaller suppliers might be disadvantaged if they could not get access to equipment and services at the same cost as larger suppliers due to lack of scope and scale economies. In addition, if resources (particularly installation services) were scarce, costs might rise, with a proportionately greater effect on small suppliers. Consideration will need to be given, both to the potential scale of this problem, and possible solutions to it.

A model that entailed the replacement of the current practice of a supplier’s contracting with a meter provider (such as a “new entrant” provider or, more usually, one of the former regional electricity companies or National Grid) by a regionalised provider (as envisaged under the Regional Franchise Model) arrived at by tender would require careful consideration. It would need to be compatible with competition law (Article 81 of the EC Treaty and the Competition Act 1998). Such a model would be likely to favour larger metering market actors in bidding for contracts. Smaller providers would still have the opportunity to provide services to the franchise on a sub-contracted basis, but this structure might favour larger suppliers who could deliver economies of scope and scale.

This model also raises questions of governance. Regulatory oversight would be required and regulation of the franchises might be necessary to ensure proper protection for consumers.

It is difficult to assess the effect on the capacity of suppliers of metering and metering services to compete. Since metering provision and service markets were opened to competition, some changes have occurred in the market-place. However, the majority of contracts outside the larger business sector remain with local monopoly electricity distribution businesses or their subsidiaries or with National Grid.

An additional competition issue is whether small suppliers would be disadvantaged by the regional franchise model proposals, with a consequent diminution in present competition and the discouraging of new entrants. Concerted procurement arrangements would have to be devised in such a way that small suppliers were not subject to unnecessary cost or the imposition of inappropriate technology or contracts.

Provided consumers have access to their energy consumption data and the right to provide this to any third party, the energy service market (for instance advice on energy efficiency) will be open to all. The impact on energy services provision and smart homes services will need to be considered as part of the design of, and the rules governing, the market.

Small Firms Impact Test

When put into practice, the Government’s proposals on metering and billing will represent Great Britain’s implementation of, and compliance with, Article 13 of the EU Energy Services Directive (ESD). The ESD permits Member States to exclude small distributors, distribution system operators and retail energy sales companies (but not small businesses who are final customers, for whom the Government could not apply exemptions) from the application of Article 13. These small companies are defined as natural or legal persons distributing or selling less than the equivalent of 75 GWh of energy per annum or employing fewer than ten persons or whose annual turnover or balance sheet total does not exceed EUR 2 million. Whilst the Government would be prepared to apply this exclusion, it does not believe that small gas and electricity suppliers would meet its terms because of their size and turnover.
The Government has carried out two consultations on metering and billing – in November 2006 and August 2007. These consultations elicited views from several economic sectors. Very few small businesses responded to the first consultation. The second consultation referred to this, and also sought specific views about the impact of its proposals on small firms. In respect of the issue dealt with in this IA, the Federation of Small Businesses supported the provision of smart meters to the smallest businesses as part of the roll-out to the domestic sector. The Forum of Private Business was concerned about the scope for erroneous remote disconnection through smart meters, and argued for protection for small business customers. The last is a matter for Ofgem as part of its regulatory role. The Government will be discussing this, and any other issues raised by the provision of smart or advanced metering with Ofgem.

The Government’s initial view was that the impact of its proposals on small firms would not be significant, and that many aspects of the proposals would enable small firms, as customers of gas and electricity suppliers, to reduce costs by being provided with tools to help them lower expenditure on energy. In addition, where Government believed there was no evident benefit to small firms and had found little or no support for such measures – such as the provision of stand-alone display devices and comparative historical information on bills – it proposed not to apply those aspects of the proposals to them.

The EU Energy Services Directive (ESD) places an obligation on Government in respect of final customers. In so far as the Government’s proposals would represent its implementation of Article 13 of the ESD, the Government could not, in contradiction of a positive assessment of the costs and benefits of the proposals, exempt one or other sector from coverage of measures taken to implement the ESD. It follows that, whilst the Government has, in the light of its commitments at Chapter 5 of the Enterprise Strategy, examined whether small businesses could be partly or fully exempted from the application of this policy, or be subject to simplified enforcement, it has concluded that such exemption or simplification would not be possible in respect of these proposals. However, as noted above, the Government has not applied certain aspects of its proposals to small business where it has found no evidence of net benefit to them.

The Government has also considered, and sought views on, the impact of its proposals on small firms where they are gas and electricity suppliers. Those small suppliers that responded to the consultation held a variety of views on issues such as the preferred roll-out method, the ideal timeframe and the level of Government intervention – in terms of both metering and communications – that was required. No particular issues were raised in respect of the ability of small suppliers, as small firms, to provide smart meters, aside from the risk that it might be harder for them to purchase meters or gain access to meter-installation services. For its part, Ofgem advised that there was no significant difference in the way that large or small suppliers approached their metering arrangements. However, the Government and Ofgem, in setting the framework and taking forward any roll-out of these technologies, would seek to ensure that small suppliers were not discriminated against, particularly in terms of access to physical (meters) and human (installers) resources.

Legal aid

The proposals would not introduce new criminal sanctions or civil penalties for those eligible for legal aid, and would not, therefore, increase the workload of courts or demands for legal aid.

Sustainable development
By definition, the proposals, which are, among other things, designed to reduce energy use and carbon emissions and to promote energy efficiency, contribute to the five principles of sustainable development [see carbon assessment]. Smart metering will provide customers with tools with which to manage their energy consumption, enabling them to take greater personal responsibility for the environmental impacts of their own behaviour. It can also contribute to the enhanced management and exploitation of renewable energy resources. The proposals would particularly contribute to the need to live within environmental limits, but would also help ensure a strong, healthy and just society [see health impact assessment] and would put sound science in metering and communications technology to practical and responsible use. The proposals would promote sustainable economic development, both in terms of enhancing the strength, and improving the products, of meter and display device manufacturers, and by increasing employment and raising skills levels in the installation and maintenance of meters and communications technologies. These benefits would also apply at a regional level, including regions with higher levels of economic deprivation.

Carbon assessment
The impact on carbon is dealt with in the main body of the Impact Assessment.

Other environment
A smart metering programme would have some negative environmental impacts. The first is the costs of legacy meters. Most significant among these would be the cost of disposal of mercury from gas meters, estimated at around £1 per meter. These costs would have to be met under usual meter replacement programmes, but would be accelerated by a mandated roll-out. Meters, display devices and comms exchanges also require power to run. It is estimated that meters would require, on average, 2 watts per hour (Wh), display devices, 1.3 Wh, and comms systems, 2.5Wh. Gas meters would require batteries for transmitting data. Typically these should last for 7-10 years, as their power consumption is very low. Some display devices would also use batteries. The batteries would be subject to the Directive on Batteries and Accumulators.

Health
The proposals raise no apparent health issues, although they have scope to improve public health and reduce health inequalities. In so far as smart meters enable suppliers better to target energy efficiency measures, which confer health benefits to individuals – particularly vulnerable individuals – deriving from greater thermal comfort, the proposals would ultimately promote better public health, reduce GP appointments and hospital visits etc. Depending on the communications technologies and smart devices that are used, there may be scope for remote monitoring of vulnerable householders by health or social services.

Race equality
The proposals raise no apparent race equality issues.

Disability equality
In 2006, BERR published its Disability Equality Scheme, which is a framework within which to meet obligations under the Disability Discrimination Act 2006. In respect of these proposals, BERR and Ofgem, as public authorities, have a duty to promote disability equality, including in policy design and development.

Whilst the smart metering proposals would broadly assist disabled customers, BERR is concerned that they should be implemented in such a way as to maximise the benefits that customers with physical or mental disabilities can obtain from them, and
to seek to avoid any adverse consequences for such customers. It is likely that an attendant display device, rather than the meter itself, would be the element that might present problems for some disabled customers. BERR would, therefore, undertake an equality assessment. This would, in the first instance, entail discussion of the potential requirements of disabled customers with a range of interested organisations. This would, in turn, inform its discussions with Ofgem and gas and electricity suppliers about what specific interventions would be required to assist disabled customers, and how those interventions might be made.

Gender equality

The proposals raise no apparent gender equality issues.

Human rights

These proposals may engage the following Convention rights: Article 6 (right to a fair trial); Article 8 (right to privacy); and Article 1 of the First Protocol (protection of property).

Article 1, Protocol 1 may be engaged because a Government mandate to roll out smart meters would entail changes to supply licence conditions, which might constitute an interference with a licensee’s possessions. Any changes to the current market structure might also engage this right. However, in BERR’s view, any interference would have to be proportionate to the benefits that this policy would accrue.

Article 8 may be engaged because smart technology will enable a supplier to receive real-time information about a customer’s energy use in his property. In addition, to roll out smart meters, installers will have to enter customers’ property. If these proposals engage Article 8, BERR’s view is that any interference would be proportionate to the benefits of the policy and necessary in the interests of the economic well-being of the country.

Ofgem is responsible for enforcing the conditions of gas and electricity supply licences. BERR’s view is that the existing enforcement regime under the Electricity Act 1989 and the Gas Act 1986 (which, for example, give licensees the opportunity to apply to the court to challenge any order made, or penalty imposed, by Ofgem), which would continue to apply during a roll-out of smart meters, is compliant with Article 6. In addition, as a public authority, Ofgem is bound by section 6 of the Human Rights Act 1998 to act compatibly with the European Convention on Human Rights.

Rural proofing

If introduced, smart meters would address the problems attached to “difficult to read” meters, which may at present lead to those in rural areas receiving fewer actual meter readings. The scope for introducing different payment methods for smart prepayment meters would assist those in rural areas who find key-charging or token purchase difficult. The opportunity, through smart meters, to provide more targeted and tailored energy efficiency advice would also assist those in rural areas, including those in “hard to treat” dwellings.
Annex 1 – Qualitative analysis of policy options
For reference notes on dual fuel efficiencies and current metering market structure are provided at the end of this annex.

Option 1: No domestic smart metering mandate but a better billing and displays policy
There would be no Government intervention on domestic smart metering but implementation of the proposals on billing (primarily provision of historic comparative data) and displays as set out in the August 2007 consultation on billing and metering. The Government decides to not go ahead with smart metering but still continues with its policies of more informative bills and visual displays on request for two years, and with new and replacement meters.

Under this option there would be benefits in energy saving through the use of displays and additional consumption information on bills. This should raise consumers’ general awareness of energy use and encourage consideration of ways to save energy. Easy access to broad consumption information on a display is likely to increase consumers’ self reporting of meter readings. The provision of historical data on bills will also raise awareness enabling consumers to compare different periods of use. However beyond these benefits there would be none of the wider benefits of smart metering.

This approach would not facilitate time of use tariffs and the additional savings at peak this could generate. Bills will continue to be a mixture of accurate and estimated and still rely on manual meter readings, estimates plus self reporting of meter readings which will not be more frequent than quarterly. Most energy suppliers seek to provide four accurate bills a year and most people get at least two accurate bills a year and it should be noted that estimated bills are usually around 90% accurate. If there are requirements for new non-smart meters to be provided with integrated links to displays then consumers will see their real-time and cumulative energy consumption with 100% accuracy. However, this is only true for as long as there is no change in tariffs or bills: as soon as there were changes in tariffs the display would have to be manually updated. It cannot be assumed that customers would want or be able to do this so over time the accuracy of the display in terms of bill data will reduce. This could lead to confusion and, potentially, consumer complaints.

For Pre-Payment Meters (PPM) the current situation would continue although where there was a business case suppliers may install smart meters so some savings would be seen in this area. Suppliers are already trialling more advanced technology prepayment meters, for example to make payments and top-ups easier through mobile phone texting.

This approach would not require changes to the current market framework and it would therefore be expected that competition and opportunity for innovation are not adversely affected, although the spur to further innovation offered by smart meters would be lost.

Options 2a-d: Mandated roll out of smart meters under various technology options and roll out speeds
These options use existing market structures within which the Government would mandate a universal roll-out of smart metering. Within the quantitative analysis various different technology options are explored and a ten year roll-out or a new and
replacement approach contrasted. Responsibility for meter provision would remain with suppliers as at present.

**Market**

The existing market structures remain in place and would evolve to deliver the mandated policy, which has an underlying principal advantage of a high degree of certainty. Whilst this is an evolution of the market – rather than a revolution – uncertainty and risk should be reduced, however regulatory monitoring would be required. This approach maintains current competitive pressures on suppliers who would be making market efficient decisions; suppliers would be responsible for roll-out of smart metering and competitive pressures between suppliers should minimise costs to consumers and provide greater consumer protection overall – suppliers could be expected to work to ensure all costs were not passed on because this would affect their competitive position. There would also be more freedom for suppliers to innovate and react dynamically to the changing needs of customers.

Roll-out would be expected to start within two years as major market changes are avoided. Within a competitive market for both meters and energy suppliers will look for opportunities to differentiate themselves from competitors, this should create incentives for innovation both in terms of technology choice and services offered, although ensuring interoperability would remain important. The earlier start of smart meter delivery would also mean the environmental benefits start earlier.

This would not be a centrally organised approach; that is there would not be a single organising body specifically charged with the roll out of smart metering. This could have a number of consequences: the potential for multiple visits to the same property by different suppliers, reduced potential for a full dual fuel solution (although this is only relevant for 50% of households), geographic dispersal of roll-out and the potential for suppliers to provide different incompatible communications solutions – although if compatibility were ensured this would be an advantage as it would reduce the risk of a single inappropriate technology being selected. These factors could result in a poorer overall customer experience of the roll-out and a possible lack of engagement, because delivery is likely to be fragmented and the drivers to create a regional “buzz” or targeted campaigns may be less. Technical solutions or industry agreements could be found to resolve some of these issues (as currently happens with bids for activities often made on a regional basis), but this could add complexity and therefore cost to the roll-out.

Within the mandate suppliers will be free to decide on the level of functionality they wish to install and the metering services they wish to procure and from where. These will be commercial decisions for them within the market. However it will be necessary for the regulator to ensure that there is interoperability to ensure competition is maintained (i.e. systems aren’t developed that exclude others), and consideration will need to be given to how smart meters affect the market, how data flows are managed and whether the industry structures need to be adjusted.

**Competition and innovation**

This approach would be an evolution of the current market framework and would be expected to increase or at the minimum maintain broadly the current levels of competition and innovation in the metering market, providing that interoperability agreements did not effectively restrict innovators from entering the market or encourage lock-in contracts.
Option 3: Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model

The Government would oversee the creation of a new regional market structure and mandate delivery of smart meters with AMM specification over a 10 year period. The regional franchise model is an approach that has been proposed by the Energy Retail Association. Responsibility for meter provision would rest with the new franchises.

Market

A tendering process would select regional franchisees to deliver a bundle of gas and electricity smart metering services for the region including the combined purchase, installation and operation of smart meters, the provision of resilient communications, data infrastructure and associated support functions. The franchise would last for the duration of the roll-out and shorter periods thereafter. The selected franchisee would purchase its metering services via competitive tendering at a regional level, and this activity could be regulated to ensure smaller actors were not disadvantaged.

The creation of a single organisation responsible geographically for delivery of all meter services would facilitate clear lines of responsibility and should within a given region result in all meters being installed with the same specification. This would ensure interoperability and avoid multiple communications networks. There would be opportunities for efficiencies of scope and scale, which should benefit consumers and suppliers.

The franchisee would have full coverage in its area, which no individual supplier could. Logistics are simplified and more readily controlled with roll-out taking place as far as possible on a street-by-street basis on a dual fuel basis. There could be efficiency gains from higher levels of access, reduction of time between visits and a single visit to change both meters. Whilst this would require a concerted effort from the franchisee to communicate with the consumers in its area it might be expected that this would be easier in this geographic approach.

This is a more integrated interface for suppliers with only one display per household and gas meters being able to piggy-back on the electricity meter. This is the only option based on a geographic roll-out, which should mean that full benefits from dual fuel as outlined below should be possible. It would be expected that a single visit per customer could be organised, which should improve customer experience with potential to create region-wide engagement in the process. Although it is noted that not all customers will stay in and the “mopping-up” of missed installations could be more dispersed, and therefore potentially costly.

For suppliers the simplification of the current market structures and a single interface with the franchisee provides an opportunity to improve data flows, back office functions and general administration. However each supplier would also have to link to each franchisee which could add a layer of complexity.

Whilst there are a number of benefits to this approach as highlighted above there are a number of risks and drawbacks. The creation of a new regional delivery model would require the creation of an entirely new market structure with attendant competition policy issues, which need to be fully investigated and understood. This is a new and untested approach and the details have not been fully developed. A number of questions remain about the governance and regulation of the new franchise, the length of time required to create it (assumed to be two-four years) and the costs associated with set up; and with the time required and costs involved in the rollback of the existing competitive market. In practice the operation of this model is
likely to require a high level of regulatory oversight to ensure that it did not lead to anti-competitive behaviour, reducing the extent to which decisions would be driven by the market.

**Competition and innovation**

Governance and the role for the regulator will require careful consideration, for instance one approach would be to licence the franchisees to be fully regulated by Ofgem (this would be a significant change to the existing system) and it is recognised that there are potential competition policy implications across this model.

This approach would require significant change to the current market framework with the creation of a number of temporary regional monopolies. The franchisee would be responsible for the roll-out and would carry most of the risk, which would therefore ultimately be born by consumers. In the case of cost increases, without regulation, there would be little incentive on suppliers not to pass costs to consumers. Although there would be some elements of competition and possible innovation in the delivery of services to the regional franchisee it would be expected that overall competition would be reduced, and innovation in the metering market limited, because the incentives to develop innovative technology options would be reduced with customers tied into one technology in an area of rapid technological change.

**Option 4: Smart metering rollout through electricity Distribution Network Operators and Gas Distribution Networks**

This is an alternative managed approach where the functions to support smart metering would be attributed to existing electricity Distribution Network Operators (DNOs) and Gas Distribution Networks, which would be mandated to roll-out smart metering within ten years. Responsibility for meter provision would shift to the DNOs and Gas Distribution Networks.

**Market**

Although a similar model to the regional franchise approach (option 3) and sharing many of the benefits and risks, this would be a fully regulated approach and would represent a full roll-back of competition in metering with attendant legal questions. As a national solution it would provide clear lines of responsibility and accountability and should deliver a number of efficiencies of scope and scale. Although it would also not naturally provide a dual-fuel roll out, given that there would only be two industry actors in any given region (one for electricity and one for gas) it should be possible to achieve a fairly high level of coordination. However as for option 3 there are questions about the cost and length of time required to rebundle metering services and the appropriate regulatory frameworks, although precedents exist.

The DNOs or Gas Distribution Networks would be responsible for the purchase, installation and operation of smart meters and feedback devices, the provision of resilient communications, data infrastructure and associated support functions. Whilst this creates some degree of simplicity and ensures interoperability it carries a major risk related to the selection of a single technology.

**Competition and innovation**

This approach would require significant changes to the current market framework with the rolling-back of metering competition. The rolling back of competition may
undermine the legitimate expectations of those currently in the market, particularly the smaller players, and remove incentives and opportunities for innovation and create transfer of undertaking (TUPE) issues. Due to the lack of competitive pressures there is the potential for such an approach to reduce efficiency. There is also a risk in selecting a single technology for the roll-out – if the selected technology failed or was found to be inappropriate significant cost and delivery issues could arise. However this also needs to be balanced against risks associated with having a number of different technologies.

It should also be noted that Ofgem moved responsibility for meters away from the networks and placed it with the suppliers and opened up the market to competition because of the levels of complaints about poor service and poor incentives to keep costs low or innovate when under monopoly provision.

Option 5: Infrastructure provider for a 10 year rollout

This is a managed approach where the functions to support smart metering (essentially the communications architecture) would be attributed to a new infrastructure provider, which would be mandated to roll-out smart metering within ten years. Responsibility for meter provision would remain with suppliers as at present.

The infrastructure provider would provide a communications and support infrastructure into which suppliers could connect smart meters. The suppliers would make commercial decisions as to the level of specification of the actual meter installed within the mandate set by Government. However there would be a risk associated if an inappropriate technology was selected.

Market

The new market functions required for implementing and operating smart metering (resilient communications, data infrastructure and associated support functions) are provided on a national basis by a single service provider. The smart meters would then be installed by suppliers and linked into the communications infrastructure. This would ensure that suppliers could access data from any meters, which would help consumers switch, accessing and sharing aggregated information for network management would be easier. There would be simplified back office data management for suppliers (they only interface with one data provider). There would be clear accountability for the management and provision of the communications infrastructure and data management/security. The provision of such communications networks is not currently an area of expertise for suppliers and the opening of this aspect of the roll-out to other players could therefore be an advantage and would ensure a level playing field for all interested parties.

Under this option efficiencies of scope and scale could be envisaged with a national managed communications infrastructure ensuring that suppliers could plug-in to the new system and that roll-out would happen in the timescales set out and systems would be interoperable. It would also eliminate the need for overlapping (potentially non-interoperable) communications networks. However there would be risks with the creation of a dedicated new communications network on this scale given the speed with which communications technologies move. Suppliers would be responsible for the roll out of meters, so it will be difficult to achieve full dual fuel efficiencies; a similar scenario as under the competitive market options.

Competition and innovation

The infrastructure provider would be appointed through a competitive process, but
would then be in a monopoly position, with attendant potential competition policy questions although this would (within the context of the energy markets) be a new service rather than the rolling back of existing competitive market structures. There would potentially be higher costs because of a lack of competitive pressure and questions as to the regulatory regime required. Competition and therefore incentives to innovate would remain in the metering market although potentially limited by the communications infrastructure. Time to roll-out would be dictated by mandate. It is likely that it would require some time to address legal, regulatory and financial issues and create the new infrastructure provider, but this would probably be less than a DNO/Gas Distribution Networks type option as it would not be necessary to roll-back existing competition in the meter market, but functionality could be limited by communications. There will be some stranding costs (as with any accelerated roll-out).

**Option 6: Indirect government mandate**

Within existing market structures the Government sets out specific outputs it requires energy suppliers to deliver for consumers and a timeframe for delivery. This option is more about the legislative approach than the substance of a mandated roll-out of smart meters. Depending on the outputs mandated this approach would share much of the analysis given for the competitive market models discussed earlier.

For example Government could mandate for the provision of *clear and 100% accurate bills for all consumers and an accurate real time display of electricity and/or gas consumption information in the home*. Suppliers would need to assess the most cost effective way to deliver the outputs required, which in this example would probably be smart meters (as the dynamics of the business case might shift away from the alternative of more frequent meter reader visits and smart meters would be the only way to guarantee readings). Additional requirements could be imposed such as being able to provide time of use tariffs or micro generation measurement, which again would, in effect, require the installation of smart meters.

Whilst Government would not mandate required functions in effect the outcomes selected would imply a certain level of functionality. This solution would also imply delivery within existing competitive market structures and it would allow maximum flexibility to suppliers to innovate and select technology solutions they deem most appropriate. In practice for this approach to work there would need to be an agreement on basic interoperability which would ensure continued ability for consumers to switch suppliers – the risk being that otherwise each supplier takes a different approach to communications protocols and technology deployed. A lack of interoperability could lead to the necessity to change a meter when supplier changed, which could be a barrier to competition and increase costs for consumers.

An advantage of this approach is that government would not need to define a smart meter allowing freedom within the market to innovate and respond to future market developments; maintaining competitive pressures. Minimum changes to the market structure and regulation would be required as under a competitive market roll-out and suppliers could be mandated to proceed quickly with minimal Government involvement required.

Although unlikely this approach could lead to the continuation of the status quo if unforeseen approaches to deliver the specified outputs are found, which fall short of delivering the full benefits of smart.

A variant of this approach would involve some mandate by the Government on either the meter or the roll out length as well as specifying the outcomes that would have to
be achieved. This approach has the advantage of ensuring that it will be known what minimum level of technology will be deployed and the mandate could be used to ensure interoperability. The mandate would require smart meters as opposed to the entirely open approach made possible by an outcomes-only policy.

**Dual fuel efficiencies**

There is the potential for a roll-out of smart metering to be more or less efficient depending on how electricity and gas systems work together. The potential for efficiencies occurs in different ways depending on the roll-out model adopted, but the basic aspects and features are outlined here.

For displays – if a combined gas and electricity solution is not deployed there is the potential for consumers to receive two displays (one for each fuel), this would be costly and possibly confusing for consumers and is assumed not to be the case.

On meters three different approaches are possible;

i. the separate installation of a gas meter and an electricity meter – each with smart functions (either a smart meter or a smart box) and each would have individual communications capability (and possibly a different communications system), this would be a more costly approach and would probably be more disruptive for consumers;

ii. the gas meter could piggy-back on electricity meter, with the electricity meter providing the communications links, this reduces costs, but meters would not necessarily be replaced at the same time, although as noted above this is applicable to half of households; and

iii. fitting both gas and electricity meters at same time gives the highest potential efficiencies; it could minimise disruption and ensure higher rates of roll-out (two meters at a time) – however, there are stranding implications, practical difficulties with different actual time taken to install the different meters and the extent to which installers are (or can be) dual skilled.

More centrally managed approaches such as those detailed for options 3, 4 or 5 are considered to more naturally facilitate the most efficient, possibly lower cost, dual fuel solutions under either ii or iii above (although options 4 and 5 might require more regulation). Although with a degree of logistical effort it is likely that dual fuel approaches could be organised within any roll-out, the benefits are expected to be higher in the managed approached but are difficult to quantify.

**Current metering market structure**

Historically all metering services were the responsibility of the distribution networks i.e. National Grid for gas and the regional electricity DNOs. However, provision of metering ownership/services was deregulated in 2003 for electricity and 2004 for gas. Competition for all elements of the chain was introduced and responsibility for delivering these services was transferred to the suppliers.

The status-quo situation is therefore that provision of meters and related services are the responsibility of the suppliers. Under this set up each supplier has contracts in place with various parties to provide meters (i.e. asset ownership), meter operations (fitting / maintenance), meter reading and data aggregation. There is a varying level of vertical integration of these services. On change of supplier the ownership of the meter usually remains with the original company who owned the meter under the previous supplier and a deemed contract for costs is made with the new supplier. Provision of all other services connected with that meter (maintenance, meter
reading etc) may be transferred to the new suppliers' preferred service provider, or remain with the existing provider of those services.
Annex 2 – Benefits assumptions

Valuing Energy Reductions

Appraisal of Costs and Benefits of Smart Meter Roll-Out Options (Page 48) - MML

Previous analysis (by Ofgem and BERR) has valued the energy savings on the basis of the energy component (assumed to be about 35%/50%) of the residential tariff or average annual bill (for electricity and gas, respectively). There is some merit in this approach, although the energy percentage needs to be adjusted up by the technical loss rates on the transmission and distribution networks (about 8% combined for electricity and 3% for gas). Also the energy component should reflect expectations of future energy costs, including for electricity the value of EU Allowances (carbon emission allowances). Making allowance for the higher energy costs and the losses increases the energy related component to almost 50%, or 4.5p/kWh for electricity and 55% for gas.

All this assumes that residential consumers’ energy costs are based on base-load (or flat) prices, which is not the case in practice. The patterns of residential load for electricity and gas both show marked daily and seasonal variations, with annual average load factors averaging 37% and 53%, respectively. Given, that wholesale energy prices are higher at peak periods this implies that the average price of meeting the residential load shape is higher than the base-load price. In recent years this market premium has been about 10-15% for both electricity and gas. Adjusting for this peaky profile premium increases the value of energy to 5p/kWh and 2.5p/kWh for electricity and gas respectively.

Of course, this reflects a short run value of energy saved, as no allowance is made for avoided overheads, investment and operating costs of network operators and retailers.

On a national basis, assuming an average electricity and gas consumer uses 4,000kWh and 25,000kWh a year respectively, the annual value of the savings works out to £5.60 for electricity and £6.25 for gas.

Residential consumers making energy savings will capture the full tariff price of the energy, assuming they have no standing charge element in their tariff. Their suppliers will therefore see the loss of the full tariff price. The suppliers energy purchase costs should fall in direct proportion, while both transmission and distribution charges could see significant reductions, depending on whether the energy saving is matched by a similar load reduction. So perhaps 3p out of 4p of the transmission and distribution charges will be offset. However, the supplier’s own business costs are largely fixed, in the sense of being weakly correlated with customer numbers (and even less so with sales). The implication of this is that energy savings will squeeze the margin of suppliers, perhaps by around 2p/kWh.

Shift of energy demand and Time of use tariffs (ToU tariffs)

Benefits from load shifting arises if the shift of energy consumption from peak to off-peak times leads to cost reductions for consumers, suppliers and eventually network operators. ToU tariffs will be possible as a result of the smart meters’ ability to store electricity usage data and provide it to the supplier.

Should 20% of the population shift 5% of peak load, this will lead to an average reduction of 1% of peak load19. Consumer savings per year would amount to about £8.70 annually, assuming an average yearly energy bill of £349 and that savings can be made on the variable part of the retail tariff assumed to be 50% of the total tariff.

19 In a perfect market we would assume that everybody that can save money would take up the ToU tariff.
Given the low savings possible from ToU tariffs (£9/year) we assume that a high take up rate of the voluntary ToU tariffs is unlikely. It is also not clear whether current Economy 7 customers would take up ToU and how many other customers may be interested given that a large amount of effort is needed, with a small number of appliances (generally only ‘wet’ appliances to shift consumption from peak to off peak hours.

It is questionable if changes in consumption behaviour will continue over time or if consumers would fall back into their old patterns of behaviour. Fears of increasing electricity bills, under the new tariff arrangements, should reduce take-up from new customers.

Currently Economy 7 tariffs are available for UK consumers, uptake is around 20%. However, it is likely that a high number of Economy 7 users would be better off on normal tariffs. Advice for Economy 7 consumers suggests that in the absence of night storage heating, consumers should only take up Economy 7 if they intend to use more than about 20% of their energy during the early morning (or night). Others suggest that by using an average of 37% of their electricity at night and early morning, consumers would be still worse off compared to people with standard tariffs.

As ToU tariffs will be voluntary, the tariff structure (the difference between peak and off-peak prices) needs to be sufficiently high to incentivise load shifting. The potential of shifting peak load is not universal across consumers and stakeholders have mentioned that it is difficult to structure a ToU tariff that provides a strong enough incentive to persuade customers to run appliances off-peak. From discussions with industry stakeholders we heard that a 700-1000% price difference between off-peak and peak tariffs might be needed to give an adequate incentive.

We have also considered the possibility of ‘lifestyle tariffs’ (similar to the mobile market) as a potential new development in the market. Those lifestyle tariffs may be structured as one-off fees with unlimited energy use during a month. Should those kinds of tariffs or other similar price structure emerge (alongside ToU), they may work against load shifting and possibly even increase peak consumption. They would be used by suppliers to take more of the consumer surplus (pricing everyone at the point they are willing to pay) and thus will be beneficial to suppliers and detrimental to consumers.

It has also been mentioned to us that suppliers may want to wait until all costumers have fully functioning smart meters before engaging in ToU pricing (therefore no benefits from ToU would be realized by at least 2020). Suppliers will only be able to run the ToU tariffs if there are enough consumers to make the investment in the system worthwhile.

Some stakeholders have suggested that there will be benefits from load shifting through Critical Peak Pricing (CPP) tariffs. CPP tariffs are characterised by having much higher peak to off peak prices over a small proportion of the year/day. Periods of peak pricing may vary depending on anticipated high-demand days of the year (set 24 hours in advance and notified to the customer through a message sent to the meter). Considering the fact that in case of CPP consumers would need to monitor their RTDs very closely, we assume that there would be no take up.

Considering that more renewable energy will be deployed in the next 20 years a reduction of peak load and thus a smoothing of demand could be beneficial for the network in the long term. Thus there could be arguments that under those new arrangements suppliers and network owners would have more interest in peak load shifting. However, in order to achieve significant changes in consumption the market

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20 These assumptions are taken from the ‘Tempo’ tariff in France.
may need a whole infrastructure of energy services and availability of energy saving appliances as well as policies that allow and promote the smoothing of energy consumption.

As most smart home services\textsuperscript{21} and smart appliances are not yet available, benefits can not be assessed. However, it may be possible that further evidence and technology developments may allow the quantification of such benefits at a later stage.

BERR has concluded that due to unpredictable developments in ToU tariffs and a high likelihood of limited take up of ToU tariffs, low benefits from ToU should be considered in this IA. We assume a 20\% take up of tariffs but only a 3\% saving in bills for consumers, but a 5\% load shift. Further evidence and technology developments, such as the development of smart homes services and smart home appliances, may lead to greater future benefits. Lifestyle tariffs are unlikely to produce a benefit to society and will only make suppliers better off at the expense of consumers. Benefits\textsuperscript{22} from ToU tariffs that have been discussed by different studies in the literature are summarised below.

**Table 22: Summary of Benefits from ToU tariffs**

<table>
<thead>
<tr>
<th></th>
<th>Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Consumer benefits</strong></td>
<td>Savings from reduced energy bills.</td>
</tr>
<tr>
<td><strong>Why?</strong></td>
<td>People shift their consumption into cheaper off-peak times where consumption is cheaper\textsuperscript{23}.</td>
</tr>
<tr>
<td><strong>How?</strong></td>
<td>Savings depend on the tariff structures (pricing) and the ability of people to shift peak load into off-peak hours.</td>
</tr>
<tr>
<td><strong>Supplier/Producer benefits</strong></td>
<td>Savings from smoothing of demand over peak and off-peak times.</td>
</tr>
<tr>
<td><strong>Why?</strong></td>
<td>Suppliers and/or producer may save costs (peak capacity costs) through smoothing of energy demand (reducing costs for expensive peak generation).</td>
</tr>
<tr>
<td><strong>How?</strong></td>
<td>Savings depend on the predictability of peak load reductions.</td>
</tr>
<tr>
<td><strong>Network benefits</strong></td>
<td>Savings from a reduction in network costs.</td>
</tr>
<tr>
<td><strong>Why?</strong></td>
<td>Peak load reductions could, in the long term, reduce overall network capacity. There may be savings from less investment in new power stations and/or network infrastructure.</td>
</tr>
<tr>
<td><strong>How?</strong></td>
<td>Savings depend on the reliability of peak load reductions.</td>
</tr>
<tr>
<td><strong>Green Benefits</strong></td>
<td>Carbon savings from peak load shifting.</td>
</tr>
<tr>
<td><strong>Why?</strong></td>
<td>Savings could occur if the marginal emission intensities are higher at peak than at off-peak times.</td>
</tr>
<tr>
<td><strong>How?</strong></td>
<td>Savings depend on the marginal emission intensity that is not predictable in the long term</td>
</tr>
</tbody>
</table>

**Valuing customer time**

Consumers could see a reduction in the time spent making complaints and waiting in for their meter to be read once smart meters have been rolled out.

\textsuperscript{21} Services such as appliances or electricity switched on/off remotely when on people go on holiday or stay out for the night, boilers that are linked to a weather forecast, washing machines that can be turned on/off remotely, energy efficiency services, etc.

\textsuperscript{22} All benefits are assumed to accrue only to electricity meters as peak load is not a significant problem for gas where prices are settled on a daily rather than half-hourly basis and thus suppliers have less incentive to get peak load reductions.

\textsuperscript{23} This saving materializes because suppliers can buy off-peak energy cheaper and pass through this saving to the consumer.
Energywatch had estimated the benefits of avoided time spent making complaints to suppliers at £60m a year or £1.31/ meter. This was on the basis that consumer time matched that of suppliers and consumers’ time was valued at the minimum wage of £5.35/hour. For waiting in for the meter reader energywatch assumed that meters are read once a year and that 1 in 6 households have to stay in specifically to have their meters read. Assuming minimum wage for the time spent by consumers and with a modest assumption of an hour wait then around £25 million per year is wasted by consumers waiting in for their meter to be read. With smart meters this wastage could be halved (2 year mandatory inspection). This is equivalent to £0.45 per meter per year.

Estimating customer time savings has not been included in previous energy impact assessments for energy policies (to our knowledge), so this would be setting a precedent if it was included. If consumer time is valued in this impact assessment then it would have to be included in previous energy IAs; which would generally result in higher costs.

It could be argued that the costs savings for consumers are cancelled out by the extra (consumer time) costs caused by smart meters. As regards fewer complaints it is possible that consumers still spend the same amount of time viewing both the more detailed bills and the RTD, resolving problems without having to contact the supplier. The amount of complaints may not decrease significantly as consumers still complain when they have more accurate information, e.g. mobile phone contracts. It is also likely that the number of complaints will increase during the rollout of smart meters.

Consumers not having to stay in for meter readings savings could be cancelled by having to stay in for more frequent meter replacement (smart meters will have a shorter life). It is debatable whether as many as 1 in 6 households have to stay in during the year as few meter reading appointments are made, but this is difficult to test.

BERR feel that consumer time is worth considering for smart meters as one of the major benefits for consumers is that they no longer have to stay in for their meter to be read and they will have a much clearer accurate bill. Although when the potential consumer time costs are considered then it is not as clear that there will be actual consumer time savings from smart meters, especially in the short term. We have decided that the potential costs to consumers’ time from smart meters balance out the potential time savings but this could possibly be investigated further after the trials have finished.
Annex 3 – Communications Costs

MML has provided us with a range of different communication options which are not all going to be assessed here. The following table provides an overview of the communication options included in the MML report:

Table 23: Overview of communication options in MML:

<table>
<thead>
<tr>
<th>Communications Options</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>GSM SMS</td>
<td>Mobile phone based technology using SMS</td>
</tr>
<tr>
<td>GSM GPRS</td>
<td>Mobile phone based technology using GPRS</td>
</tr>
<tr>
<td>3G</td>
<td>Mobile phone based technology using 3G</td>
</tr>
<tr>
<td>WiMax&lt;sup&gt;24&lt;/sup&gt;</td>
<td>Using the Wimax spectrum (providing wireless data over long distances)</td>
</tr>
<tr>
<td>Broadband</td>
<td>New line broadband service</td>
</tr>
<tr>
<td>Piggyback broadband</td>
<td>Broadband service based on existing broadband line</td>
</tr>
<tr>
<td>PLC &amp; SMS</td>
<td>PLC works through the electricity distributor’s network. The PLC network acts as an access network reducing the number of links needed to connect the meters. Based on SMS technology.</td>
</tr>
<tr>
<td>PLC &amp; Broadband backhaul</td>
<td>PLC based on broadband.</td>
</tr>
<tr>
<td>PSTN Flat rate</td>
<td>Public switched telephone network with a newly installed telephone line on a flat rate basis</td>
</tr>
<tr>
<td>PSTN PAYG</td>
<td>Public switched telephone network with a newly installed telephone line on pay-as-you-go basis</td>
</tr>
<tr>
<td>Hybrid 1 (PLC and Wimax)</td>
<td>A combination of broadband based PLC and Wimax technology</td>
</tr>
<tr>
<td>Hybrid 2 (Broadband and 3G)</td>
<td>A combination of piggyback broadband and 3G</td>
</tr>
</tbody>
</table>

Communications Options

The appropriate starting point for our work is to base our analysis on the communications methods that are currently available and for which costs are best understood. Suppliers may not use these communications technologies but we assume that they may find lower costs (or extra benefits) as more research is made into possible options. Although there exist a large number of communication options, some more current, some less proven in the market, we decided to focus on two scenarios. Those are:

- a hybrid of piggyback broadband and 3G technology. This option is at the cheaper end of the ‘communication scale’ and takes advantage of existing communications networks;
- hybrid 1: A more expensive option is Enhanced Narrowband PLC (based on broadband) combined with Wimax (a GSM technology).<sup>25</sup> and
- a self contained national radio network.

We approach the questions of communications in such a way that we will initially line out the costs of communications devices that will be integrated in the meter and then talk about the fixed and variable costs that may be attached to the infrastructure or – on a yearly/monthly basis- for the communication of the data from the meter to the supplier or operator. Please be aware that those are only indicative estimates for the analysis to provide sensitivities for the impact assessment

Internal communications defines the communication between the meters or within the household. For all internal communication we have assumed that a radio (such as Zigbee devices), device will be used to communicate between electricity and gas meter. For the communication between the meter and a broadband hub a wifi device

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<sup>24</sup> Worldwide Interoperability for Microwave Access

<sup>25</sup> More information on the details of the Hybrid options in the Annex.
is used, for the communication from the meter to a smart box we also assume a Zigbee device. The GSM option includes a GSM modem that is directly fitted to the meter. For the Dumb/Smart option we depart from MML approach, and assume that the meters communicate through Zigbee devices with the smart box without reducing any ‘ability’ of this option. This was also supported by MML as a feasible approach.

The one-off capital costs for the installation of the VPN (Virtual Private Network) were annualised for all technologies and a 10% interest rate over a period of 20 years was applied. Costs were assumed as follows:
- a set-up charge (one off fee) for the VPN per supplier related to the size of the VPN in a non-linear way
- a set-up charge per meter linked to the VPN
- management charge per meter

The following costs were used in the estimates by BERR based on MML and some adjustments by BERR:

**Table 24: Cost assumption for communications devices**

<table>
<thead>
<tr>
<th>Devices</th>
<th>GSM – 3G</th>
<th>Piggyback Broadband</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zigbee card in Gas (£3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zigbee card in electricity (£1)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GSM modem card in meter (£8)</td>
<td></td>
<td>Install and configure charge (£10)</td>
</tr>
<tr>
<td>VPN £10.11</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

**Table 25: Fixed and Variable costs of communications**

<table>
<thead>
<tr>
<th>Fixed coms</th>
<th>SIM purchase £10 <strong>27</strong></th>
<th>Broadband home hub £28</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Coms</td>
<td>3G charge £5 per meter pa</td>
<td>Broadband charge £0.03 pa</td>
</tr>
</tbody>
</table>

**Table 26: Communications maintenance costs**

| Faults           | 5% of Zigbee devices= 1.4£ | 5% of Zigbee and Wifi devices 1.8£ per meter p.a. |

The following discounts were assumed for the communication devices based on the assumptions that technologies become cheaper over time and that devices will be bought in bulks. The discount is different depending on how the technology is currently priced in the market.

**Table 27: Discount factors applied for communications**

<table>
<thead>
<tr>
<th>Discount factors</th>
<th>Broadband &quot;Piggy-back&quot;</th>
<th>3G</th>
</tr>
</thead>
<tbody>
<tr>
<td>26</td>
<td>0.0%</td>
<td>46.0%</td>
</tr>
</tbody>
</table>

Additionally an optimism bias is applied. MML assumed that the optimism bias should be higher of technologies that are not yet technologically proven, thus the

---

26 Assumed to be the same as the Zigbee device
27 Only paid by the first million users, gratis for all others.
28 Assuming that this home hub would be part of a bigger home packages from suppliers such as BT or virgin who often give their ‘Smart Boxes’ for free when customers are signing up for a 12 months (or longer) contract, costs are assumed to be zero.
optimism bias on the Hybrid option is 30%. For further information on the optimism bias see Section F.

The option of a national radio network is based on the idea to install a national radio network infrastructure available to all suppliers. This setup of the infrastructure may need to be organised as a monopoly that provides services to the energy suppliers but could be managed by a conglomerate of all those suppliers. The service provider may then charge a flat fee per meter to provide the meter data to a national centre where the data can be processed and accessed by the suppliers.

This option could provide for a high rate of data transfer and would be a common, national solution. However, further analysis would need to be conducted by Ofcom regarding the regulation of such a monopoly.

BERR has included an estimate of the costs of building and running such a national network to be £5 per meter per annum (flat rate fee) and £15 for the costs of a meter modem. BERR did not assume any costs for the radio spectrum but we have to assume that there may be additional costs for acquiring the spectrum.

**Table 28: MML communications cost for different technologies**

<table>
<thead>
<tr>
<th></th>
<th>PLC &amp; Broadband backhaul</th>
<th>Wimax</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Internal coms under dual-roll-out</strong></td>
<td></td>
<td>Zigbee in Electricity meter: £1</td>
</tr>
<tr>
<td>30</td>
<td></td>
<td>Zigbee Gas meter: £3</td>
</tr>
<tr>
<td><strong>External coms under dual roll-out</strong></td>
<td>PLC modem (included in capex) £34</td>
<td>Wifi card in meter 20£</td>
</tr>
</tbody>
</table>

---

30 RTD is already fitted with a transmitter and does not need the Zigbee for any communications.
Annex 4 – More detailed results

Please see below the break down of costs and benefits for each of the smart meters options. (Options 2 – 3)

Option 2a: Mandated 10-year roll out of AMM specification smart meters within existing market structures

<table>
<thead>
<tr>
<th>Costs</th>
<th>NPV £m</th>
<th>Benefits</th>
<th>NPV £m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total capital costs</td>
<td>5,425</td>
<td>Energy Saving Elec £</td>
<td>1,707</td>
</tr>
<tr>
<td>Installation costs</td>
<td>2,918</td>
<td>Energy Saving Gas £</td>
<td>1,412</td>
</tr>
<tr>
<td>O&amp;M costs</td>
<td>732</td>
<td>TOU</td>
<td>468</td>
</tr>
<tr>
<td>Comms costs</td>
<td>2,450</td>
<td>Losses - bill reduction</td>
<td>136</td>
</tr>
<tr>
<td>Energy Cost (£)</td>
<td>356</td>
<td>Total Consumer Benefits</td>
<td>3,601</td>
</tr>
<tr>
<td>Disposal Costs</td>
<td>39</td>
<td>Avoided cost of carbon Gas (£)</td>
<td>586</td>
</tr>
<tr>
<td>IT System Costs</td>
<td>65</td>
<td>Avoided meter reading</td>
<td>2,977</td>
</tr>
<tr>
<td>Pavement Reading Inefficiency</td>
<td>1,138</td>
<td>Inbound enquiries</td>
<td>1,058</td>
</tr>
<tr>
<td>Legal &amp; Contractual</td>
<td>253</td>
<td>Customer service ovhds</td>
<td>183</td>
</tr>
<tr>
<td><strong>Total Costs (£)</strong></td>
<td><strong>13,374</strong></td>
<td><strong>Debt Handling</strong></td>
<td><strong>248</strong></td>
</tr>
<tr>
<td><strong>Total Consumer Benefits</strong></td>
<td></td>
<td><strong>Avoided PPM COS premium</strong></td>
<td><strong>456</strong></td>
</tr>
<tr>
<td><strong>Total Supplier Benefits</strong></td>
<td></td>
<td><strong>Remote Connect/Disconnect</strong></td>
<td><strong>248</strong></td>
</tr>
<tr>
<td><strong>Total Other Benefits</strong></td>
<td></td>
<td><strong>Avoided site visit</strong></td>
<td><strong>423</strong></td>
</tr>
<tr>
<td><strong>Total Benefits</strong></td>
<td><strong>12,027</strong></td>
<td><strong>Reduced Losses</strong></td>
<td><strong>127</strong></td>
</tr>
<tr>
<td><strong>Net Benefits</strong></td>
<td></td>
<td><strong>Reduced Theft</strong></td>
<td><strong>115</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Microgeneration</strong></td>
<td><strong>11</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Supplier switching benefits</strong></td>
<td><strong>1,151</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Supplier Benefits (£)</strong></td>
<td><strong>4,466</strong></td>
</tr>
</tbody>
</table>

Option 2b: Mandated 10-year roll out of AMR specification smart meters within existing market structures

<table>
<thead>
<tr>
<th>Costs (£)</th>
<th>NPV £m</th>
<th>Benefits (£)</th>
<th>NPV £m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total capital costs</td>
<td>3,249</td>
<td>Energy Saving Elec £</td>
<td>1,707</td>
</tr>
<tr>
<td>Installation costs</td>
<td>2,636</td>
<td>Energy Saving Gas £</td>
<td>1,412</td>
</tr>
<tr>
<td>O&amp;M costs</td>
<td>394</td>
<td>Reduced Losses</td>
<td>127</td>
</tr>
<tr>
<td>Comms costs</td>
<td>2,450</td>
<td>Total Consumer Benefits</td>
<td>3,133</td>
</tr>
<tr>
<td>Energy Cost (£)</td>
<td>287</td>
<td>Avoided cost of carbon Gas (£)</td>
<td>586</td>
</tr>
<tr>
<td>Disposal Costs</td>
<td>39</td>
<td>Total Supplier Benefits (£)</td>
<td><strong>4,466</strong></td>
</tr>
<tr>
<td>System Costs</td>
<td>65</td>
<td>Reduced Theft</td>
<td>115</td>
</tr>
<tr>
<td>Pavement Reading Inefficiency</td>
<td>1,138</td>
<td>Reduced Losses</td>
<td>127</td>
</tr>
<tr>
<td>Legal &amp; Contractual</td>
<td>253</td>
<td>Supplier switching benefits</td>
<td>1,151</td>
</tr>
<tr>
<td><strong>Total Costs (£)</strong></td>
<td><strong>10,510</strong></td>
<td><strong>Customer service ovhds</strong></td>
<td><strong>183</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Debt Handling</strong></td>
<td><strong>248</strong></td>
</tr>
</tbody>
</table>
### Option 2c: Mandated 10-year rollout of 'smart box' technology (equivalent to AMR meter specification) within existing market structures

<table>
<thead>
<tr>
<th>Costs</th>
<th>NPV £m</th>
<th>Benefits</th>
<th>NPV £m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total capital costs</td>
<td>3,288</td>
<td>Energy Saving Elec £</td>
<td>1,707</td>
</tr>
<tr>
<td>Installation costs</td>
<td>2,196</td>
<td>Energy Saving Gas £</td>
<td>1,412</td>
</tr>
<tr>
<td>Comms costs</td>
<td>2,450</td>
<td>Reduced Losses</td>
<td>127</td>
</tr>
<tr>
<td>Energy Cost</td>
<td>219</td>
<td>Total Consumer Benefits</td>
<td>3,133</td>
</tr>
<tr>
<td>System Costs</td>
<td>65</td>
<td>Avoided cost of carbon Gas (£)</td>
<td>586</td>
</tr>
<tr>
<td>Pavement Reading Inefficiency</td>
<td>1,138</td>
<td>Avoided meter reading</td>
<td>2,977</td>
</tr>
<tr>
<td>Legal &amp; Contractual</td>
<td>253</td>
<td>Inbound enquiries</td>
<td>1,058</td>
</tr>
<tr>
<td><strong>Total Costs (£)</strong></td>
<td><strong>9,608</strong></td>
<td>Customer service ovhds</td>
<td>183</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Debt Handling</td>
<td>248</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Supplier Total</td>
<td>4,466</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Theft</td>
<td>115</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Losses</td>
<td>127</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Supplier switching benefit</td>
<td>1,151</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Other Benefits (£)</strong></td>
<td><strong>1,393</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Benefits</strong></td>
<td><strong>9,578</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Net Benefits</strong></td>
<td><strong>(30)</strong></td>
</tr>
</tbody>
</table>

### Option 2d: Mandated new and replacement roll out of AMM specification smart meters within existing market structures

<table>
<thead>
<tr>
<th>Costs</th>
<th>NPV £m</th>
<th>Benefits</th>
<th>NPV £m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital costs total</td>
<td>2,669</td>
<td>Energy Saving Elec £</td>
<td>980</td>
</tr>
<tr>
<td>Installation costs</td>
<td>3,533</td>
<td>Energy Saving Gas £</td>
<td>801</td>
</tr>
<tr>
<td>O &amp; M costs</td>
<td>408</td>
<td>TOU</td>
<td>261</td>
</tr>
<tr>
<td>Comms</td>
<td>1,239</td>
<td>Losses - bill reduction</td>
<td>76</td>
</tr>
<tr>
<td>Energy Cost (£)</td>
<td>198</td>
<td>Total Consumer Benefits</td>
<td>2,047</td>
</tr>
<tr>
<td>IT System Costs</td>
<td>65</td>
<td>Avoided cost of carbon Gas (£)</td>
<td>341</td>
</tr>
<tr>
<td>Pavement Reading Inefficiency</td>
<td>2,413</td>
<td>Avoided meter reading</td>
<td>1,659</td>
</tr>
<tr>
<td>Legal &amp; Contractual</td>
<td>126</td>
<td>Inbound enquiries</td>
<td>589</td>
</tr>
<tr>
<td><strong>Total Costs (£)</strong></td>
<td><strong>7,982</strong></td>
<td>Customer service ovhds</td>
<td>102</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Debt Handling</td>
<td>608</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avoided PPM COS premium</td>
<td>254</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Remote Connect/Disconnect</td>
<td>138</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avoided site visit</td>
<td>236</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Supplier Benefits</strong></td>
<td><strong>3,586</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Losses</td>
<td>71</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Theft</td>
<td>64</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Microgeneration</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Settlement System</td>
<td>641</td>
</tr>
</tbody>
</table>
Option 3: Mandated 10-year roll out of AMM specification smart meters in a regional franchise market model

<table>
<thead>
<tr>
<th>Costs</th>
<th>NPV £m</th>
<th>Benefits</th>
<th>NPV £m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital costs total</td>
<td>5,213</td>
<td>Energy Saving Elec £</td>
<td>1,657</td>
</tr>
<tr>
<td>Installation costs</td>
<td>2,310</td>
<td>Energy Saving Gas £</td>
<td>1,369</td>
</tr>
<tr>
<td>O &amp; M costs</td>
<td>708</td>
<td>TOU</td>
<td>453</td>
</tr>
<tr>
<td>Comms cost</td>
<td>2,650</td>
<td>Losses - bill reduction</td>
<td>132</td>
</tr>
<tr>
<td>Energy Cost (£)</td>
<td>344</td>
<td>Total Consumer Benefits</td>
<td>3,492</td>
</tr>
<tr>
<td>Disposal Costs</td>
<td>39</td>
<td>Avoided cost of carbon Gas (£)</td>
<td>571</td>
</tr>
<tr>
<td>IT System Costs</td>
<td>56</td>
<td>Avoided meter reading</td>
<td>2,881</td>
</tr>
<tr>
<td>Pavement Reading Inefficiency</td>
<td>730</td>
<td>Inbound enquiries</td>
<td>1,024</td>
</tr>
<tr>
<td>Legal &amp; Contractual</td>
<td>632</td>
<td>Customer service ovhds</td>
<td>177</td>
</tr>
<tr>
<td><strong>Total Costs (£)</strong></td>
<td><strong>12,682</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total Supplier Benefits</td>
<td>6,229</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Losses</td>
<td>123</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduced Theft</td>
<td>111</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Microgeneration</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Supplier switching benefit</td>
<td>1,114</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Other Benefits (£)</strong></td>
<td><strong>1,359</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Total Benefits</strong></td>
<td><strong>11,650</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Net Benefits</strong></td>
<td><strong>(1,032)</strong></td>
</tr>
</tbody>
</table>

| Total Other Benefits (£)     | 782    |
| Total Benefits               | 6,756  |
| Net Benefits                 | (1,226)|