Coal Mine Methane – Review of the Mechanisms for Control of Emissions

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EXECUTIVE SUMMARY

Objectives

The objectives of this report are to assess:

- The available technical options for the control of Coal Mine Methane (CMM) emissions from abandoned mines; and
- The deployment of market and other non-market mechanisms to control CMM emissions from abandoned mines.

The report is not required to come to any recommendations or conclusions as to the most suitable methods of control.

Introduction

Since the early 1990's in particular, significant numbers of coal mines have been closed and abandoned in the UK. Before that period the widespread interconnection of mines within coalfields meant that methane emissions from abandoned mines flowed into operating mines, where the scale of emissions was masked. Once large sections of coalfields closed during the 90's the methane from abandoned mines began to manifest itself more directly as uncontrolled emissions to the surface, posing a threat to public safety. The Coal Authority addressed this by the provision of vents to prevent uncontrolled emissions to the surface. It was also seen by some as an opportunity to exploit a potentially valuable energy resource. A number of companies were formed and schemes implemented to extract and utilise the gas from abandoned mine sites with sizeable emissions. Members of the Association of Coal Mine Methane Operators (ACMMO) invested £26million in the industry and at present extract methane at a rate of 31kt/year. However, ACMMO's view is that the implemented schemes are no longer financially viable.

Methane is a powerful greenhouse gas (GHG) with a greenhouse warming potential (GWP) of 21. The UK emission inventory of methane in 2001 was 2195kt or 46MtCO_2e. There is some uncertainty as to the total emission from abandoned mines that would take place without control, but IMC believe that it is of the order of 1MtCO_2e. This represents about 2% of the total methane emission from all sources, but only about 1% of the UK's required reduction of greenhouse gas emissions under the Kyoto Protocol of 74MtCO_2e. It follows that emissions of methane from abandoned coal mines are not likely to be significant in the context of the UK's commitments to reduce GHG emissions under the Kyoto Protocol.

At present the emission rates from abandoned mines are not well characterised, and are currently subject to a separate investigation by IMC Consulting Engineers on behalf of DEFRA.

Summary of work

Estimation of Current Emissions

The first stage of the study was to obtain an estimate of the quantity of gas that would be released from abandoned mine sites where control would be feasible, if no control measures were in place. A survey carried out on behalf of the Coal Authority in 2002 to measure gas flows formed the basis of the calculation. The survey made spot measurements at a number of venting sites around the country. Not all vent sites were visited and spot measurements are not necessarily representative of average emissions. Nevertheless the data was used to calculate an emission from those venting sites covered in the survey. Measurements at sites not included in the survey together with an estimate of the total emission from vents with low methane flows (<10l/s) were added. The quantity of gas being utilised by ACMMO members was also added to the sum. A distribution of the emission into flow bands was carried out and an estimate of the number of sites within each band provided.

An estimate was also calculated for the change in emission over the next ten years based on a hyperbolic decay function and average methane flows at operating collieries.

The assessment of current annual emissions from sites where control measures could be applied is estimated to be 52kt/y. There is a large uncertainty in this number as it relies on spot measurements, does not include potential emissions from some sites, takes no account of acceleration by commercial extraction and does not include emissions other than at vents.

The analysis of the distribution of emissions into different emission bands and a figure for potentially controllable methane flows provides the estimated flow per year into each emission flow band displayed in Table 1.

Table 1. Summary of Gas Emission Quantities from Different Sources

	Methane Emission l/s			
	<15	15-50	50-150	150+
Estimated per cent of Total of 52kt/year	5.0%	13.0%	30.3%	51.7%
Estimated Methane Flow kt/year	2.6	6.7	15.89	26.9
Estimated Number of sites of which (are current commercial extraction sites).	-	9 (1)	6 (2)	6 (4)

Also included in Table 1 is an estimate of the potential number of sites within each band. The numbers of sites and the proportion of emission in each band are indicative due to the uncertainty in the emission estimates. However, the sites where commercial extraction takes place are included within the relevant emission band.

Estimates of emissions in ten years time are 64kt/y assuming no further flooding of mines and 43kt/y assuming natural flooding. Since these values are based on ‘average’ mines, the closure of actual mines may produce large variations in these figures.

Technical Options for Controlling Emissions

The technical options for controlling emissions from abandoned mines were divided into three main groupings that were:

- Inhibiting Flow;
- Methane Transformation; and
- Enrichment.

Inhibiting flow covered sealing mine openings and vents, restricting the flow by means of non-return valves and flooding of the mines.

Methane transformation included Flaring, Direct Oxidisation using catalysts, the Generation of Electricity, Indirect Consumption, Injection into a gas grid, CHP, LNG, Fuel Cells and biological control.

Enrichment included Pressure Swing Adsorption, Selective Adsorption and Cryogenic Enrichment.

In view of the difficulties in achieving control of emissions and the concomitant risks to safety from uncontrolled emissions the general use of sealing or application of flow restrictors was considered inappropriate. The use of flooding required a large source of water, generally unavailable, and could result in a premature requirement for the Coal Authority to prevent environmentally damaging surface water discharges. Therefore, this option is not considered to be appropriate.

For methane transformation the fuel cell and biological technologies are discounted on the grounds of cost and being unproven at a practical level in the UK. These options fail to address the non-carbon issues of other pollutants within the gas (eg H_2S). The burner tip technology although accounting for three of the existing schemes in the UK are currently discounted due to the lack of identifiable new consumers. CHP schemes are similarly discounted.

The remaining technologies of flaring (including direct oxidation), generation and injection into a gas grid are techniques that are immediately available for controlling emissions. Equipment is now obtainable for both flaring and generation that is able to transform a wide range of methane concentrations (1% to 100%) that are typical of CMM emissions. Similarly, CMM emissions can be treated to enable injection into a gas grid but at a greater cost than the other options.

A comparison of the estimated costs for these technologies is given in Table 2. For flaring a range of costs are given from estimates derived from the UK and USA. Generation costs are based on information from ACMMO and for a range of electricity prices and connection charges. Capital costs include equipment, site engineering and acquisition as well as project development. Operational costs include estimates for administration, maintenance etc. The overall costs have been calculated using a 10% discount rate over a seven-year period. The Table shows the cost per tonne of CO_2 equivalent and the emission in terms of CO_2 equivalent for each emission band. The figures show that Gas upgrade is by far the most expensive option. The costs for generation and flaring are closer although flaring is marginally cheaper. The cost figures presented here should be regarded as indicative rather than definitive, being the result of a simple financial analysis.

The abatement costs in Table 3 can be compared with current estimates for the marginal damage costs estimated to be ~£19/tCO_2e, a figure one order of magnitude higher than flaring or generation.

The total costs calculated include the costs of mitigation at sites where the utilisation of the gas is already underway. The absence of these schemes would place the burden of mitigation elsewhere.

Table 2. Table Showing Costs of each Technology Abatement Option

Methane Flow rate litres/second (l/s)	**0 to 15 l/s**	**15 to 50 l/s**	**50 to 150 l/s**	**150 to 400 l/s**
CO2e in each measured range (kt/y)	55	141	330	564
Unit Cost Mitigation				
Flaring (£/tCO_2e) GWP (Greenhouse Warming Potential) 18.25	N/A	**3.6 to 8.6**	**1.4 to 4.2**	**0.8 to 2.9**
Generation (£/tCO_2e) GWP 21	N/A	**6.5 to 7.9**	**2.6 to 6.0**	**2.2 to 4.9**
Gas Upgrade (£/tCO_2e) GWP 21	N/A	**27.2**	**10.5**	**4.4**
Total Cost Mitigation (Over seven years)				
Flaring (£millions) - Low cost	N/A	3.6	3.2	3.0
- High cost		8.5	9.6	11.4
Generation (£millions) - Low cost	N/A	6.4	6.1	8.6
- High cost		7.8	13.8	19.3
Gas Upgrade (£millions)	N/A	26.8	24.1	17.3

Review of Existing Market Mechanisms

A variety of support mechanisms have been identified to encourage the use of CBM and CMM (including gas from operating mines) resources by way of feed-in tariffs, tax incentives or grant support. No support mechanism was identified to support flaring or other means of controlling emissions specifically. However, the instruments were of varied instrument typology and so are useful in providing basic ideas for instrument designed to promote CMM use. A summary of the schemes investigated is provided in Table 3.

Whilst a number of policy instruments that result in the control of CMM were identified all the policies related to the promotion of CMM utilisation. No instruments were identified which promoted flaring or use in gas distribution networks (the other two technical options considered as options in UK CMM control).

Table 3. Policies Stimulating the Control of CMM Emissions by Way of CMM Use (Generation)

Policy instrument	**Description**	**Country**	**Scheme status***	**Benefit to developers / suitability to project finance**
Feed-in tariff	20-year guaranteed power offtake contracts given to electricity generator	Germany	Appears very successful with c.70MW of capacity commissioned since its inception. Applied to active and abandoned mines	Very attractive due to high tariff, guaranteed for a long period of time, greatly facilitating project finance
Obligation	Obligation on energy suppliers or generators to limit CO2 emissions (Gas Abatement Scheme)	Australia	Reported to have attracted interest from the CMM industry (only active mines) which aims to accredit CMM schemes	Market-driven incentive which, if properly designed, can provide the economic impetus to developers and if structured adequately facilitates access to project finance.
Tax incentives	Production Tax Credit; a 10-year guaranteed tax-driven incentives designed to encourage electricity generation	US	Scheme not applicable anymore to CBM; however perceived to have contributed to the exploitation of more than 10,000 wells at active mines by the end of 2000	Effectively a feed-in tariff in disguise increasing certainty over level of income stream, thus facilitating project finance.
	Climate change levy	UK	Scheme introduced in 2003: limited impact today.	An incentive improving project economics, but unlikely to be sufficient on its own in the context of low wholesale electricity market in the UK
Grants	50% grant towards project costs	Australia	Five projects at active mines have already received funding, with the scheme anticipated to be fully subscribed to by end of 2004	Grants can provide a significant boost and be suitable to project finance if adequately designed.
* Note that the cost of each scheme was not investigated, being outside the scope of the Terms of Reference.				

Policy Options Investigation

A total of eighteen policy options were initially identified and discussed as a possible means of controlling CMM emissions. They comprise a mix of obligations, market-based incentives, tax breaks, feed-in tariffs, and direct grants/support, which might prove to be complimentary in some instances. Table 4 provides an overview of these policy instruments:

Non-Market Barriers

There are significant non-market barriers that restrict the development of CMM mitigation projects and these are discussed within the report. The barriers include

- Access to land to implement control measures, including land under public ownership by Local Authorities and Regional Development Agencies;
- Delays and difficulty in obtaining planning consents;
- Delay, lack of transparency and cost associated with obtaining connection to the electricity grid, a barrier affecting all distributed generators;
- Licence difficulties including conflict between different types of licence to deal with CMM and the costs and obligations associated with them. Licences are granted by the DTI, the owners of the gas. To exploit CMM reserves it is normally necessary to obtain a PEDL (Petroleum, Exploration and Development Licence) which requires the holder to carry out work within specific time frames. The licences, obtained by competitive bid, cover clearly defined geographical areas. Ownership of the gas passes to the licence holder on capture. In contrast, operating mines require a MDL (Methane Drainage Licence) in order to vent or utilise gas for public safety or safety of a mine. The Coal Authority operates under a Venting Licence, covering the whole of the UK, which allows for the venting of mine gas to atmosphere for the purposes of safety. The Coal Authority does not own the gas and it is unclear whether a Venting Licence allows for gas to be flared or utilised;
- The Coal Authority's relationship with PEDL owners and the work carried out with regard to public safety;
- The delay to or lack of provision for access to gas from an abandoned mine soon after closure.

These issues largely require resolution by Government.

Table 4. Policy Instruments Envisaged for Controlling CMM Emissions in the UK

Options	**Policy instrument**	**Description**	**Suitability**
1	Extend the Enhanced Capital Allowances scheme to CMM emissions control equipment	100% first-year capital allowances on selected equipment	Would enhance the attractiveness of an investment in the sector but is unlikely to provide the level of incentives to ensure CMM control on its own, also subject to adequate tax structuring
2&3	Joint Implementation for flaring and/ or generation	System which allows trading of Emission Reduction Units to raise finance.	Methane from abandoned mines not in the UK national Inventory. Unlikely to be implemented in the short term.
4&5	Grant for flaring and/or generation	Government funds paid to support flaring or generation schemes.	Use of existing administrative infrastructure has the ability to mobilise capital relatively quickly and be tailored to support either flaring and/ or generation in a flexible manner
6	Include CMM in the Renewable Obligation	Recognise the environmental benefits associated with the use of CMM resources for electricity generation by granting it renewable status	Confirmed by the DTI as not consistent with Government policy.
7&8	Obligation on the Coal Authority to flare and/ or generate	Extension of the CA's role to mitigate CMM emissions with a possible involvement of the private sector by way of a PFI/PPP type delivery mechanism	Subject to adequate structuring and appropriate consultation with relevant stakeholders, involvement of the private sector on the basis of a tender may produce the best value for money for the government,
9&10	Tax on polluters to support flaring and generation	Venting/ Flaring Tax Tax On Newly Closed Coal Mines	Would not, on its own, lead to emissions control.; a possible source of revenue to finance other policy options (eg, grants)
11	EU Emissions Trading System	EU scheme to allow trading of carbon credits	Offers little in the short-term; applicability not anticipated before 2008.
12-15	Tax Offset to support flaring and/or generation	Petroleum Revenue Tax Offset	Effectively another source of revenue to finance, say, a grant programme
16	Do nothing	No-change	Could be real opportunity costs and social costs for do nothing approach
17	Implement a Feed-in Tariff	Obligation on utilities to purchase methane from abandoned mines.	Unlikely to fit within the UK policies
18	UK ETS	Entry into UK Emissions Trading Scheme	UK projects work-stream has effectively been abandoned. Not suitable.

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1. INTRODUCTION

Since the early 1990's in particular, significant numbers of coal mines have been closed and abandoned in the UK. Before that period the widespread interconnection of mines within coalfields meant that methane emissions from abandoned mines flowed into operating mines, where the problem was masked. Once large sections of coalfields closed during the 90's the methane from abandoned mines began to manifest itself more directly as uncontrolled emissions to the surface. This was addressed by the Coal Authority by the provision of vents to prevent uncontrolled emissions to the surface. It was also seen by some as an opportunity to exploit a potentially valuable energy resource. A number of companies were set up and schemes implemented to extract and utilise the gas from a number of sites with sizeable emissions. Members of the Association of Coal Mine Methane Operators (ACMMO) invested £26million in the industry and at present extract methane at a rate of 31kt/year. However, the implemented schemes are no longer financially viable.

Methane is a powerful greenhouse gas (GHG) with a greenhouse warming potential (GWP) of 21. The UK emission inventory of methane in 2001 was 2195kt or 46MtCO_2e. There is some uncertainty as to the total emission from abandoned mines that would take place without control, but IMC believe that it is of the order of 1MtCO_2e. This represents about 2% of the total methane emission from all sources, but only about 1% of the UK's required reduction of greenhouse gas emissions under the Kyoto Protocol of 74MtCO_2e. It follows that emissions of methane from abandoned coal mines are not likely to be significant in the context of the UK's commitments to reduce GHG emissions under the Kyoto Protocol.

At present the emissions rates from abandoned mines are not well characterised, and are currently subject to a separate investigation by IMC Consulting Engineers on behalf of DEFRA.

The objectives of this report are to assess:

The available technical options for the control of CMM emissions; and
The deployment of market and non-market mechanisms to control emissions.

In the Terms of Reference for this project methane from abandoned mines is described as CMM (Coal Mine Methane) and this report has followed the same usage.

1.1. Approach

The approach employed in this report is to:

- Estimate the size of methane emissions from abandoned mine workings;
- Review and assess the technical options currently implemented or under consideration for CMM control;
- Review mechanisms for stimulating CMM mitigation, financial and otherwise.

The first section of the report provides an estimate of the size of the flows from vents and other sources and to allocate these flows within broad bands of emission.

The technical options are considered in Section 3 and their suitability measured against the principal criteria of cost of carbon mitigated and ease of implementation. Some of the technical options considered are more expensive than others and some technical options require more time and further research before implementation. Additionally, emissions too low for mitigation by the technical options available have been excluded from consideration.

The cost of carbon mitigated is calculated in terms of pounds per tonne of carbon dioxide equivalent ascribed to each technical option for each band of emission. A cost for mitigating each band of emission for different options will also be calculated. The carbon dioxide equivalent calculation has used a Greenhouse Warming Potential (GWP) for methane of 21 where generation is the option or 18.25 where conversion results in a net additional CO_2 emission.

In assessing market and non-market mechanisms that could be used to encourage the mitigation of CMM emissions, a review of existing mechanisms has been carried out. This has included a study of existing UK and overseas mechanisms.

Section 5 assesses a number of possible policy options that could be implemented to encourage the mitigation of CMM within the UK. These options comprise a range of obligations, market based incentives, tax breaks, feed in tariffs and direct support. Although considered individually the options could be used in combination to provide the most suitable solution.

Finally there is an assessment of the non-market barriers to the reduction of methane emissions.

2. EMISSIONS OF METHANE FROM ABANDONED MINES

This Section sets down a brief description and results of an assessment of the present and future emissions of methane from abandoned mine workings in the UK. However, for reasons outlined below there is some uncertainty associated with these figures. A more detailed description of the emissions from abandoned mines together with the current extraction by CMM operators is given in Appendix A.

2.1. Estimation of Current Methane Emissions

A study funded by DEFRA is at present underway, the objective of which is to develop a methodology to determine the level of methane emission from abandoned mines [1]. The study also requires the level of methane emissions to be calculated. Methane emission falls into two main categories. The first is from vents into abandoned mines, the second is from diffuse emissions released over large poorly defined areas. Progress has been made on the measurement of methane emissions from a number of vents, calculations of gas reserves, water levels in the coalfields and measurements of low level concentrations of methane in ambient air within various coalfield areas.

At present, insufficient information has been collected by the DEFRA study to come to any conclusion as to the total emission from abandoned mines. The methodology being developed requires data from all sources to be combined to produce the total emission. However, measurements of the levels of methane in ambient air have shown increases in concentration in those areas where gas emission might be expected. In future, the concentrations should be transformed into methane fluxes, giving a measurement of the diffuse emission from the workings.

Appendix A sets out the calculation method used to estimate the current annual mine gas emission. The calculation makes an assessment of the emission from vents based on a set of spot measurements carried out for the Coal Authority [2]. Also included was an assessment of the flow from vents with total flows of less than 10l/s and measurements from vents not included in the Coal Authority survey. A contribution of gas quantities being used by commercial users has also been added, although there still remains some question as to the degree of acceleration which is taking place (Appendix A.3.). The results are set out in Table 1.

Table 1. Summary of Annual Methane Emission Quantities from Different Sources

SOURCE	**QUANTITY (kt Methane)**
Vents	
Latest Coal Authority Vent Survey, Feb 2003 (Amended by IMC)	18
Estimate of emission from low flow vents	1
Other Measured sites	2
Collected for Utilisation, data supplied by ACMMO	31
Total Vents	**52**
Diffuse Emissions	Unknown

For the following assessment, a value of 52kt/y has been used as an estimate for the methane emission which would be released from vents in the absence of control. No allowance has been made for acceleration at commercial extraction sites due to uncertainty in the degree of acceleration. No evidence of the degree of acceleration is available, so any estimate of its value would be speculative. However, the inclusion of 31kt/y is likely to be an overestimate. The uncertainty in the vent measurements and natural flows of the utilisation sites means that the total methane flow from those sources included in Table 1 is probably only accurate to within about 30%. The level of diffuse emissions is uncertain, but it is hoped that the DEFRA study might shed some light on the magnitude of these emissions. It is possible that some of these diffuse emissions could be captured by schemes designed to control emissions from vents.

The value of 52kt/y is equivalent to about 1Mt/y CO_2e. Earlier studies suggested that methane emissions could have been between 2Mt/y CO_2e and 12Mt/y CO_2e. However, previous estimates have been based on extrapolating from areas of abandoned mine workings and the assumption that all workings vent gas to the surface. An assessment of the validity of this assertion is awaited from the DEFRA study.

Table 2 contains an estimate of the measurable total methane emissions delineated into four emission bands. The band boundaries are set at 15l/s, 50l/s, and 150l/s methane. Also included in Table 2 is an estimate of the potential number of sites within each band. The number of sites within each emission band are estimates for the present time based largely on a distribution and not, in most cases on actual sites. (Appendix A) However, the number of sites where commercial extraction takes place have been included within the relevant emission band. It should also be recognised that the figures are very dependent on spot measurements and are therefore subject to error. Nevertheless, the two vents at Askern, two vents at Hem Heath and a vent at Prince of Wales are sites where flows would fall within the upper two categories of flow within the Table. (At present, emissions at Prince of Wales are being controlled under a methane drainage license, although the colliery is closed.) These five vents, together with the six of seven sites where commercial extraction takes place at flows in excess of 50l/s tallies closely with the 12 sites estimated from the distribution in excess of 50l/s (Table A1, Appendix A). Before any implementation of control measures an assessment of the quantity of gas being released for each potential vent will be needed to determine baseline emissions and facilitate design of the control system. The numbers of sites and the proportion of emission in each band must therefore be seen as a general indication only and not hard and fast figures. It should also be recognised that these figures provide an estimate of the position at present, but the situation will change with time due to emission decay and the closure of collieries.

Table 2. Estimated Split of Methane Emission into Bands of Emission Rate

	Methane Emission l/s			
	<15	15-50	50-150	150+
Estimated per cent of Total of 52kt	5.0%	13.0%	30.3%	51.7%
Estimated Methane Flow kt/year	2.6	6.7	15.89	26.9
Estimated Number of sites of which (are current commercial extraction sites).	-	9 (1)	6 (2)	6 (4)

2.2. Estimate of Future Emissions

Appendix A describes the calculation used to project current emissions forward for the next 10 years. Figure 1 shows the estimated changes in projected emission for existing vents (bottom line) and also including additional emissions from newly closed collieries (top line). These curves take no account of flooding. It is assumed that one operating colliery closes per year over the next ten tears. A third line (middle line) shows a possible reduction in methane emission due to rising mine water over the same period. It is assumed for the purposes of the calculation that emissions from sources will halve in a linear fashion over the next 10 years due to the effect of rising water.

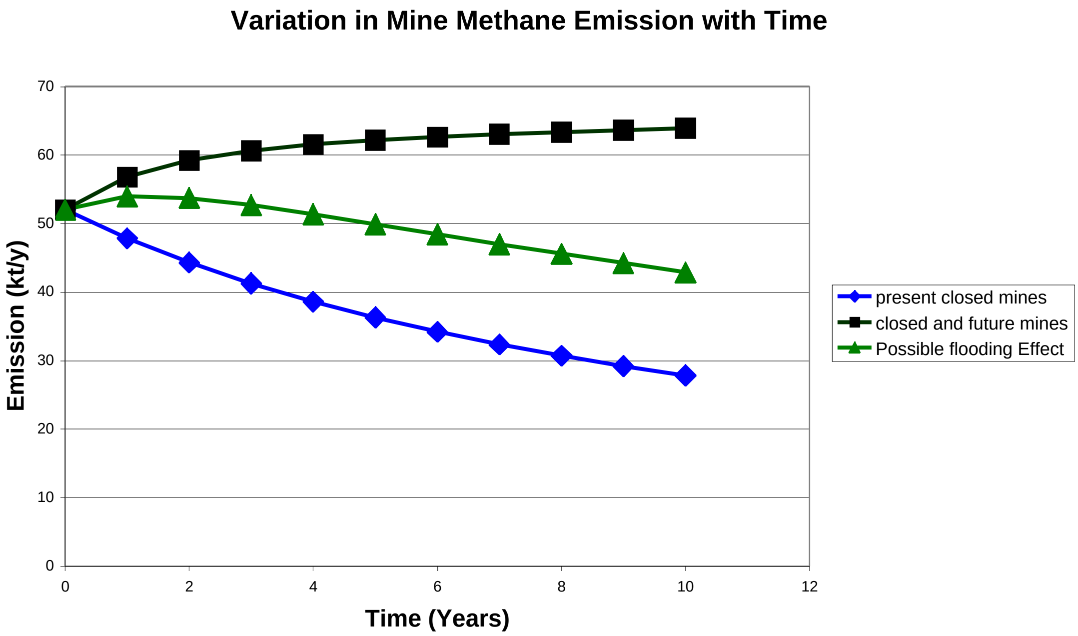

Figure 1. Estimates of Changes in Mine Gas Emission from Vents over the Next Ten Years

The future emission calculations rely on an estimate of how the emission from a colliery decreases with time. Appendix A uses a hyperbolic decay curve, based on measurements made by the National Coal Board in 1969, of the form:

$$F=A/(t+k)$$

In the equation, F is the emission expressed as a percentage of the methane emission before closure, A is a positive constant (65%), t is the time in years since closure and k constant (1.5). The form of the curve is shown in Figure 2. The curve demonstrates that emission rates are highest soon after closure and soon fall to lower levels.

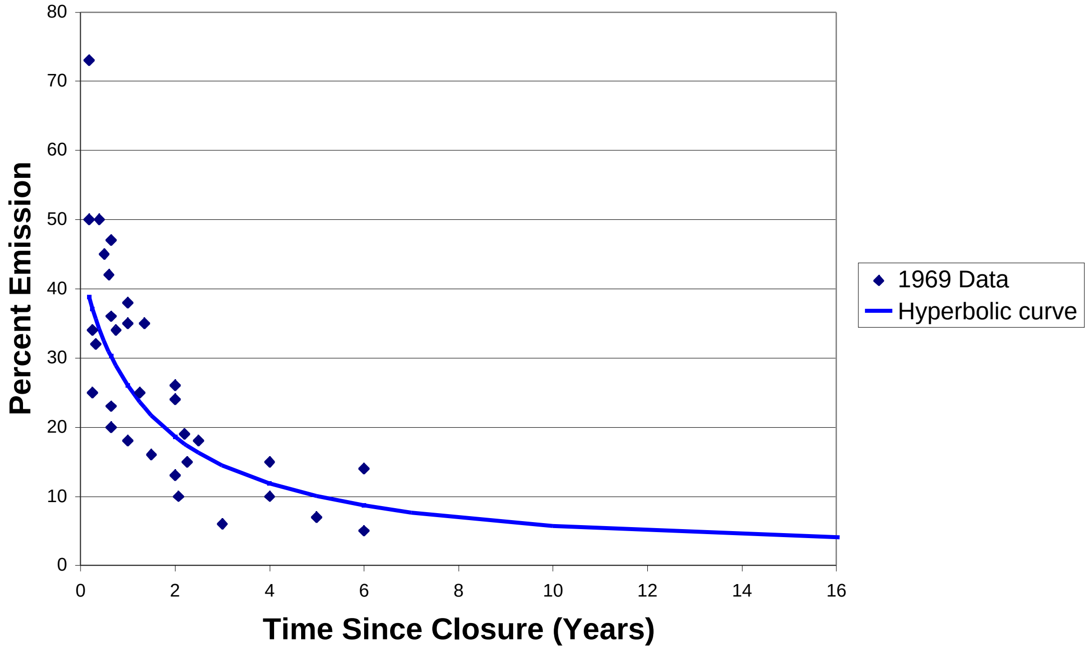

Figure 2. Change in Methane Emission from Abandoned Mines Following Closure

Initially, any newly closed mine is likely to be in the higher band of emission, gradually moving to the lower bands as the time since closure increases. The projected closure of mines over the next ten years or so will bring new mines into the higher emission category, where they remain for three years or so before passing into the next lower band of emission. They may remain in that band for around seven years. These are only general figures, but highlight that the process is dynamic and that the number of sites in the upper categories will heavily depend on the timing of individual mine closures. It should be borne in mind that even if the closure history means that the number of sites within each band remain reasonably stable over the next 10 years or so, the individual sites within each band will change.

The closure of operating collieries also has an important impact on the emissions. At most sites in the past, utilisation of the methane from abandoned mines only began some years after closure. Given that the rates of emission are highest close to closure, it is important that any control measures should be planned into the closure programme so that the gas can be controlled very soon after the mine is closed. Unless this occurs a large part of the total expected emission could be released before the implementation of control measures. For example, using an average emission for presently operating mines and using the hyperbolic decay curve in Figure 2, the estimated methane emission from a closed colliery in the first 2 years (14kt) represents 48% of the total estimated emission over the first 10 years (29kt). This illustration includes the assumption that flooding would further reduce methane emissions by half in 10 years in addition to the natural reduction in emission due to the decay of emission from gas sources.

3. TECHNICAL OPTIONS FOR CONTROLLING EMISSIONS

Methane emissions from abandoned mine workings to the atmosphere can be reduced by:

- Inhibiting flow
- Transforming the methane to other compounds.

In the UK a risk assessment is carried out prior to abandonment of a mine in which the probability of mine gas being emitted at the surface is assessed. Where no risk is perceived the mine openings may be sealed in accordance with best practice and no provision made for venting of any mine gas. Where risk of surface emissions is perceived passive vents are installed, generally in one or more of the mine openings, in order to minimise gas pressures within the workings.

Methane may be transformed by oxidation, including combustion. Options for Direct Combustion are to flare the gas or to use it in electricity generation at or close to the emission site. Alternatively, the gas may be piped either directly to an industrial user or into a gas distribution system [3]. Consumers of mines gas in the UK have generally been industrial users looking for cheaper sources of gas. Currently there are three such consumers in the UK; one where gas is extracted from a borehole on site, one where the gas is piped a short distance from the extraction point and one where gas is piped some distance through an existing (ex British Coal) pipeline.

Additional benefit from transforming the methane is that other toxins and odiferous compounds sometimes associated with gas from abandoned mines may also be transformed.

3.1. Inhibiting Flow

Inhibiting flow might be achieved by

- Sealing of all pathways where methane is detected or likely to be emitted.
- Restricting flows from vents
- Flooding the gas producing workings.

3.1.1. Sealing

Where the perceived risk from uncontrolled surface emissions is very low, mine entries have been sealed on abandonment. However, due to the extensive spatial and temporal nature of mine workings, interconnectivity of collieries, phasing of closures, mine water recovery and subsequent surface developments, risks may change requiring vents to be installed post closure. For example in 1994 the Coal Authority were responsible for some 80 gas vents only some of which emitted methane, but in 2003 the Coal Authority has some 120 vents from which methane is emitted. These figures exclude colliery closures during the period. The increase in the number is due to additional vents being installed to protect the safety of people affected by surface emissions.

Sealing of the mine openings can result in high gas pressures within the workings as rising mine water isolates the workings. There are or have been a number of abandoned mine sites without venting that have resulted in high gas pressures (>200kPa) within the workings. A majority of the known sites have been responsible for surface leakage along geological faults (Horbury, Rotherham and St Helens) and have subsequently been vented to control risks to affected property. Even where mine openings are vented, albeit poorly connected to the workings, leakage may occur through mining induced fractures or permeable strata. In several cases leakage occurs around the surface where services or fractured strata are connected to the mine entry. The CMM operators have been involved in remedial works at their extraction wells (mine shafts and drifts) to prevent leakage. These works can cost in excess of £100,000 (Wheldale £157,000, Shirebrook £108,000) and may not guarantee success [4].

Where emissions pathways are poorly defined (shallow workings, permeable strata such as sandstone, faults or backfilled quarries etc) sealing would be technically difficult and costly. Recent figures for cement grouting of old workings range between £100,000 and £200,000 per hectare per m extraction and grouting could not be guaranteed to prevent gas migration.

Furthermore, until the DEFRA work has been completed there would be little way of verifying that overall emissions were being reduced.

Nevertheless, there may be a few isolated mine sites where the geology could make this a viable option although sealing should be carried out as part of the closure process as it is difficult to achieve once the mine openings have been abandoned. Based on the extent of the mine workings such mines are likely to represent less than 1% of current methane emissions.

3.1.2. Restricting Flows

With the exception of sites where gas is utilised or controlled by active pumping (Arkwright, Calow and Shiremoor), the UK vents are open to the atmosphere so that during increasing atmospheric pressure air can enter the vents and mine gas can be emitted during falling atmospheric pressure. However, in Germany (and at Calow) vents are equipped with non return valves preventing air from entering through the vent. The valves respond to pressure within the workings allowing mine gas to be vented during a falling atmospheric pressure. The use of these valves ensures that, where there are no leaks, the mine gas is undiluted by air so that the methane concentration is higher and more consistent than at uncontrolled vents. The disadvantage is that pressure must build up in the vent before the valve opens so increasing risks from emissions through other pathways. The use of such valves is unlikely to reduce the emissions of methane, although the exclusion of air could reduce emissions of carbon dioxide resulting from oxidation. However, since the majority of Coal Authority vents have been installed to protect specific properties or to minimise leakage around the mine openings this form of control is unlikely to be acceptable on the grounds of safety. Furthermore, the use of such a valve would add to the costs associated with the maintenance of the venting sites since the operation of the valve would need to be verified on a regular basis and require routine cleaning.

Where gas is utilised vents can be opened in the event of a break in production as for example occurred at Hickleton when the company generating the electricity went into receivership. However, during routine maintenance, the majority of sites utilising gas are maintained under suction, although provision for venting to atmosphere is available.

3.1.3. Flooding

The recovery of mine water in abandoned workings after the cessation of pumping follows an exponential rise as water flows from adjacent strata to the workings or mine entries as well as interconnected shallow workings up dip. Recovery rates are generally similar throughout the coalfields since inflow rates are proportional to area of workings. Typically, recovery occurs within 10 to 30 years. However, there are some isolated mines where recovery is considerably longer.

Mine water is pumped in areas where mines are still active and in abandoned areas where there is a risk of contamination of aquifers or surface discharges. Since privatisation, water levels have been allowed to rise in a controlled manner in those areas where pumping has been continued by the Coal Authority. However, if the levels were allowed to rise to their natural rest level in these areas it is estimated that no more than 2.5% of the methane reserves would become flooded.

Active flooding of mine workings is only considered to be viable where there will be no risk to aquifers and surface discharges, otherwise flooding would bring forward the requirement for pumping and treatment. The Coal Authority is responsible, through a memorandum of understanding with the Environment Agency, for minewater treatment schemes and is committed to a programme of implementation based upon natural recovery rates. The Coal Authority has expressed concern about any presumption in favour of flooding since the control of minewater underground is a key element in the prevention of pollution by minewater. If flooding were to be adopted the Coal Authority would require additional resources (including funding) and/or changed priorities to deal with the additional water control systems.

The source of water for flooding would be problematic since, given the current overall shortage, suitable water might be difficult to locate. The most obvious source is the sea, which was used at Point of Ayr at closure. However, the only unflooded workings adjacent to the sea are at Ellington/Lynemouth, which due to its interconnections is unsuitable and the mine has already been earmarked for a pumping scheme when it closes. Minewater has been pumped from an active part of a mine to abandoned areas to reduce water discharges and had the result of limiting gas emissions into the workings. However this is not seen as a viable option for large areas.

If a source of water could be found and there was sufficient confidence that contamination would not result, the number of isolated mines where flooding could be considered is estimated to contribute less than 1% of the total methane emissions from abandoned mines.

A more detailed discussion of this topic is given in Appendix B.

3.2. Methane Transformation

3.2.1. Flaring

In the UK, land based flare systems have been developed primarily to control emissions from landfill sites. The basic components of a flare system consist of a gas inlet connected to a filter, for the elimination of dust and moisture, and a booster pump connected to a combustion chamber. In addition, various control and safety devices are normally fitted. Two principal types of flare systems are available namely open (elevated) and enclosed (ground). Open flare systems are relatively simple devices burning gas as an open flame with little to control the rate of combustion; hence emissions from such systems can be variable. The enclosed flare system has been developed to provide more stable combustion conditions with minimum temperatures of 1000^{o}C and a retention time of at least 0.3 seconds. Consequently this type of flare meets the minimum emission standards laid down by the Environment Agency taking account of the EU Landfill Directive (1999/31/EC) [5]. The current 'best practice' for the use of flares on landfill sites indicates that only enclosed flares should be used for permanent installations and that all open flares shall be replaced by the end of 2003.

Enclosed flares are available in standard ranges having flow capacities between 50l/s and 500l/s although larger capacity units can be made to order. Flare systems can usually accommodate an order of magnitude turn down in flow from the design level, although the precise flow range is dependent upon the calorific content of the gas combusted. Most flare systems operate with methane concentrations above 25%. However; systems are now available which will operate with methane concentrations as low as 5% and with flows of between 50l/s and 250l/s. Systems operating with these low methane concentrations would require a separate gas supply for the ignition phase whereas at higher methane concentrations no additional supply is required. The equipment cost of a 50 l/s flare burning methane down to 5% is about £50,000 but this only includes basic monitoring and excludes an acoustic enclosure.

UK mining legislation currently prohibits the ignition of firedamp (gas contained within coal seams and released during production, consisting principally of methane in the UK) at a mine unless the gas is burnt in a boiler or engine. However, UK Coal has been granted an exemption from this legislation and is operating an enclosed flare system at Riccall Mine with a nominal capacity of 555l/s. Two further enclosed flare systems are currently being commissioned at Maltby Colliery. The flares at these mines burn excess firedamp collected by the underground gas drainage system which is not used for heating the pit head baths or for electrical generation. The equipment cost of the flare at Riccall is believed to be around £75,000 although the additional safety systems agreed with HM Mining Inspectorate together with other engineering added a further £25,000 to the project.

In the US a design for a flare handling flows between 30l/s and 400l/s for use on a gob gas well was developed in 1995 with further refinements to the design being made in 1999 [6,7]. It is understood that the design has been used at one mine in Australia. In 2000 the estimated equipment cost (inclusive of project development, installation and planning) for the US flare was £48,000 with an annual operating and maintenance (O&M) cost of £10,000. However, these costs were for an open flare, a system not meeting the EU Landfill Directive. Estimated costs for an enclosed flare were £100,000 for equipment and £11,200 for annual O&M costs. The O&M costs included moving equipment once every two years, a situation not likely to apply to UK abandoned mine vents. The estimated annual O&M cost excluding the costs for moving the plant is some £8,000 [8]. These cost estimates are likely to be less than for similar equipment that could be sited in the UK due to the location of abandoned mine vents (generally in urban environments or areas under redevelopment) compared to US gob wells (away from habitation) and concomitant planning requirements. Similarly, operating costs in the UK are likely to be higher than in the US due to the novelty of the technique (applied to mine gas) and the needs to demonstrate its safety.

3.2.2. Direct Oxidation

As an alternative to flaring there are systems able to oxidise methane (generally in low concentrations <15%) directly, producing CO_2 and water [9,10]. These systems, originally designed for VOC mitigation, use a catalyst either to oxidise the methane directly or to activate an airstream, which then oxidises the methane. The direct systems (catalytic burner and flow reversal) heats a ceramic or gravel catalyst, typically to 150^oC and will oxidise methane in concentrations lower than 5%. However, whereas some manufacturers claim the catalyst is not readily poisoned, others suggest that trace gases such as mercaptans that may be present in abandoned mine gas will poison the catalyst. Systems have been demonstrated using the ventilation air from active mines with methane concentrations of <1% (VAM technology). Laying heat exchangers within the gravel or ceramic bed can allow use of the heat of oxidation.

The air activation system passes air over a high voltage in the presence of a catalyst and the ionised air oxidises the mine gas. Since the mine gas is not in contact with the catalyst there is no risk of poisoning the catalyst.

The manufactures claim that the cost of the units is comparable with flare systems in the range up to 500l/s (total flow) and have similar turn down abilities. However, the direct system is better able to respond to varying loads than the air activation system and is less costly at high load.

Although this technology has not yet been used for gas from abandoned mines the current interest in utilising ventilation air methane suggests that further developments with reduced costs can be expected. However, of the estimated vented gas, less than 14% could be treated with this technology.

3.2.3. Generation of Electricity

Under natural conditions the gas emitted from abandoned mine vents contains methane in concentrations ranging from 0% to >90% and at many sites gas only flows intermittently. Electricity generation makes use of between 20% and 40% of the energy available in the methane. The current UK CMM industry utilises the gas to produce electricity in the 3.6MW to 7MW. However, the large capital costs involved in shaft top remedial works or borehole drilling, extraction pumps, control system, and generation equipment, as well as the high costs associated with connection to the grid, has made the existing and potential schemes not financially viable.

Traditionally, generation has been by spark ignition reciprocating internal combustion engines and these are available in sizes from several megawatts down to less than 200kW. Modern designs are fitted with emission control systems in order to meet current regulations.

Gas turbines have been used at UK collieries since the late 1970’s (with a hot water recovery unit) and combined cycle gas turbines have been used since the early 1990’s. Turbines are available in capacities from 30kW to 500MW. These engines require higher gas pressures (7bar to 14bar) than the reciprocating engines (1.3bar to 5.5bar) so that the efficiency is reduced by the need for a compressor. To minimise the loss in efficiency in some systems the compressor is driven by a reciprocating engine powered by the gas.

The interest in recovering energy from air with low concentrations of methane vented from active mines has led to the development of engines claimed to be capable of burning methane in concentrations as low as 0.86%. One microturbine system uses a compressor to feed the gas to a catalytic oxidiser where the energy released drives a 30kW generator. A system is in use in Japan where five such microturbines are used to generate 150kW. Two other prototype systems have been developed in which the lean methane mix is preheated by exhaust gases to the point where ignition occurs within the turbine. One prototype is a microturbine rated at 70kW and the other is a carburetted gas turbine rated at 2.7MW [10,11,12].

3.2.4. Indirect Consumption

Indirect consumption involves transport of the gas from the site for combustion elsewhere. The gas may be transported in a dedicated pipeline to a user or users in the locality. Costs associated are the maintenance of a quality suitable for pipeline transport and the cost of the pipeline itself. Continuity and quality of supply is also usually a major concern for the consumer.

The existing projects have been implemented because of favourable conditions that prevailed at the sites. At one site an existing British Coal gas grid connecting a mine to a number of consumers was sold to the CMM operator for a nominal sum. At another site the large consumer could be connected across an abandoned mine site and at the third site a borehole was drilled into workings on the consumer's curtilage (Rexam Glass). However, no other potential consumers have been found from the plus 100 venting sites. One of the current sites, Rexam Glass works, takes gas from part of mine workings believed to be responsible for a long running surface emission problem. The consumer would take more gas if it were available but the costs of drilling suitable additional boreholes and installing gas pipes between the two points (assuming planning permission were granted) is too great. Should the gas be extracted in this way it might obviate the necessity for a Coal Authority gas pumping scheme to be installed (Section 6.5).

Although not applicable to existing abandoned mine gas emissions the exploitation of gas reserves where emission are not known to occur could be developed in this manner.

3.2.5. Injection into Gas Grid

The gas may also be fed into the national gas network, but the gas needs to be of a high quality and to a tight specification, which will require further equipment to be utilised [13]. The specification requires the gas to have less than 2% carbon dioxide and 5% nitrogen. However, CMM may have up to 21% carbon dioxide and greater than 40% nitrogen although typically the methane concentration is greater than 50% with the balance made up of the inert gases. The national gas network operates at pressures up to 80 bar with pressures varying dependent upon demand. The high pressure lines (transmission) may be used for storage during which time pressure is increased. Connections to the network are usually made into either a local transmission system or district network. The former operates around 20bar, with diurnal variations reducing pressure by some 10bar, whereas the latter operates around 2bar. The gas must therefore be compressed in excess of these pressures gas in order to be transported from the gas well to the Transco Main and at a sufficiently high pressure to enter the main. At a discharge pressure of 7bar the energy required to pump gas into the grid represents approximately 5% of the electrical energy that would be available from the gas (100kW for a flow of 150l/s).

Estimates of the total cost of connection range from £1.5M for the higher pressure networks to some £300,000 at the lower end. Additional barriers to injection relate to the uncertainty of the CMM supply and the need to predict the daily input into the grid (errors are penalised) and the variation in spot price for the gas.

By contrast, in the Methamine project, in the Nord Pas de Calais, mine gas at 56% methane is allowed to be injected, without enrichment, into a natural gas pipeline operated by Gaz de France. In Northern France the calorific value of the gas in the gas grid lies between 34.2 and 37.8 MJ/m^3, in comparison to Transco's range of 37.5 to 43.0MJ/m^3 [14]. The gas from Methamine can be injected into the grid as long as the rest of the gas is of sufficient purity to prevent the combined gas falling below the required concentration.

3.2.6. CHP

CHP offers an increase in efficiency since the waste heat can be used for space heating or for driving additional steam turbines (combined cycle). The waste heat from reciprocating compressors fed from CMM have been used for heating workshops and offices at active mines in the UK. In addition to conventional combined cycle turbines, microturbines (Section 3.2.4) are used to provide heating [15].

However, CHP requires an end user for the heat within a short distance from the plant to minimise heat loss and transmission costs. This type of project lends itself to schemes where abandoned mine sites (with CMM supplies) are being redeveloped for housing or industry and provision is made to pipe the hot water from the plant to the buildings. However, although such sites exist (Hem Heath, Allerton Bywater) the redevelopment plans have not included this aspect. The retrospective installation of a heat distribution network would be costly and require acceptance by the owner or occupants of the properties.

3.2.7. LNG

With methane concentrations of approximately 90% CMM gas may be liquefied by cooling to approximately 110K to produce liquefied natural gas (LNG). LNG occupies a volume some 1/600 of the gaseous phase. In addition to being used as a clean replacement for other fuels LNG, can be used in transportation and currently sells at a premium. Liquefaction can remove all the impurities from CMM but would require large costly plant to achieve the necessary purity. However, using this technique would enable the gas to either be used as a liquid or vaporised to provide gas suitable for injection into the national grid. A cryogenic plant (liquefaction) is installed at Blue Creek mine where the mine gas passes through a series of heat exchangers where first any oxygen is removed, followed by carbon dioxide, water vapour and finally nitrogen [16,17,18].

Although liquefaction is generally carried out on the large scale, individual gas wells have been treated when economic or other incentives make it viable. In the US, the gas from one well has been liquefied to produce ultra high quality LNG for special purposes.

3.2.8. Fuel Cells

Methane can be used in fuel cells, via the conversion to hydrogen within the cell, to produce electricity. The feasibility of using of CMM was demonstrated at a 2MW plant in the US during 1996 and recently at Rose Valley coalmine where mine gas from the active mine has been used to generate 200kW of electricity [19].

The fuel cell technology requires a ‘clean’ methane flow so that the impurities from the mine gas must first be removed. Zinc oxide is used to remove sulphur compounds and oxygen by a platinum catalyst. The gas stream is then mixed with steam to remove the higher hydrocarbons and heated to approximately 900K. Within the fuel cell (lithium and potassium carbonate electrolyte) the methane is split into hydrogen and carbon monoxide. Some 75% of the hydrogen reacts with the carbonate to produce electricity and the remainder oxidised outside the cell. Efficiencies of up to 50% are claimed although it is believed that the existing cells operate around 44% (c.f 30% to 40%

for conventional generation). However, the budget for the 200kW unit was some >£3M although the fuel cell manufactures anticipate that ultimately costs can be reduced by at least one order of magnitude by the end of the decade. On a smaller scale proposals have been made to use a fraction of the gas flow to supply power to regulators, metering and telemetry equipment [20].

3.2.9. Biological

Since the 1980's a number of experiments have been carried out using micro-organisms to reduce methane concentrations in active mines [21,22]. The organisms used oxidise methane exothermically producing carbon dioxide and water. Although the work has shown that the technique works there have been a number of constraints that have prevented its widespread use. These constraints include the large number of organisms required, the method of containment or fixing, and the effect of the waste products (heat and carbon dioxide). However, in the case of abandoned mines these problems are less severe, particularly as flow rates are low. The gas may be used to feed micro-organisms, either for the sole purpose of getting rid of the methane or to produce useful by-products.

3.3. Enrichment

Enrichment of CMM, by the removal of nitrogen, carbon dioxide and other trace gases to create a richer methane mixture, is not by itself a means of controlling emissions but an adjunct to many of the techniques in Section 3.2 [3].

3.3.1. Pressure Swing Adsorption (PSA)

Pressure swing adsorption has been used in the UK mining industry since the early 1990's to separate nitrogen from air for controlling underground spontaneous combustion. The technique consists of two carbon molecular sieves that are pressure cycled. A pilot plant was designed for enriching drained gas at an active mine in Nottinghamshire but at privatisation the scheme was dropped. For CMM the sieves adsorb the methane preferentially under pressure (~5bar) and releases the methane when under low pressure (~1bar). By reducing the output flow, the percentage of recovered methane can be increased with 98% being the likely maximum recoverable. However, since some methane is contained within the waste gas, precautions are necessary to ensure the gas does not enter the flammable range (5% to 15% methane). Consequently, it is likely that an additional catalytic oxygen removal stage will be necessary following the PSA process.

A separate sieve for removing carbon dioxide would be necessary should injection into the gas grid be required. Small systems using a zeolite molecular sieve have been developed for separating carbon dioxide from landfill gas to enable conventional flare systems to operate.

3.3.2. Selective Adsorption

Hydrocarbon solvents are commercially available which adsorb gases preferentially. The system would require a deoxygen unit to treat the inlet gas before passing through the solvent adsorbing methane, cooling and rejecting nitrogen. Carbon dioxide could be treated in the same manner given in Section 3.3.1.

3.3.3. Cryogenic

This is the process described in Section 3.2.7.

3.4. Assessment

The assessment of the suitability of the technical options is based upon a number of criteria; the most important of which are the net cost of unit carbon mitigated and the estimated total cost.

However, in view of the difficulties in achieving control of emissions, the risks to safety from uncontrolled emissions and the possible environmental problems associated with flooding workings, the options for inhibiting flow (Section 3.1) are not considered to be appropriate.

For methane transformation the fuel cell and biological technologies are discounted on the grounds of being unproven at a practical level and fail to address the non-carbon issues (H_2S). The burner tip technology and CHP are discounted due to the lack of a consumer.

The remaining technologies of flaring (including direct oxidation), generation and injection into a gas grid are assessed in Table 3. Table 3 is largely copied from Appendix C which contains a simple financial analysis of the technical options and the reader is directed to the Appendix for the derivation of the figures in Table 3.

The Table shows the cost per tonne of CO_2 equivalent (rows nine to 20) and the total cost for each option for each emission band over a seven year period (rows 23 to 27). All figures assume a 10% discount rate. A range of estimates have been used for the flaring option based on cost estimates from the US EPA, information from UK sources to provide an IMC estimate, and ACMMO. The figures for generation and gas upgrade assume income from electricity (£21.8/MWh +/- 20%) and gas sales (£0.18/therm). One of the largest unknowns for the generation option is the cost of a REC connection. Figures from the industry indicate that the cost for existing schemes has ranged between £39,000 and £2,000,000 and is not dependent on generating capacity. The financial analysis for generation has therefore included the effect of varying the REC connection charge (rows 17 & 18).

The figures show that Gas upgrade is the most expensive option. The costs for generation and flaring are closer, the range of cost estimates overlapping, although flaring is marginally cheaper. The cost figures presented here should be regarded as indicative rather than definitive, being the result of a simple financial analysis. The costs are likely to be site specific so a detailed financial analysis would be required to assess which option was cheapest on a project by project basis. For example, two of the sites in the highest flow band are within a new housing development, in one case within 20 m of new property. Any mitigation scheme will need to be remote from the existing venting sites requiring a major investment in pipework and probable purchase of land, subject to planning conditions.

It should be noted that for the utilisation and pipeline injection figures there is likely to be some degree of acceleration. The figures in Table 3 are based on natural flow rates, i.e. no acceleration. If costs were made on the basis of gas mitigated rather than gas extracted, then the cost per tonne of CO_2 equivalent would rise to provide the required IRR. Flaring might also create some acceleration, but it would be less in this case as suction pressures are likely to be lower.

As detailed in Section 2, Table 3 includes sites where gas is currently utilised. Of the seven sites where gas is utilised four sites are in the flow rate band of 150 l/s to 400 l/s and two sites in the band 50 l/s to 150 l/s. Equating these sites with the estimated cost of generation in Table 3 indicates that the CMM industry contributes some 40% (38% of the low cost and 43% of the high cost) of the mitigation costs. The CMM industry has identified a further 100 sites with reserves (Table A1, Appendix A) which they believe contribute to the diffuse emissions (excluded in Table 3). If ACMMO are correct and should these sites be developed the proportion of mitigation costs covered by the CMM industry could be greater than the 40% indicated by Table 3.

The costs in Table 3 can be compared with current estimates for the marginal social costs (Section 5 'do nothing') estimated to be ~£19/tCO_2e, an order of magnitude higher than flaring or generation [23].

Table 3. Table showing Costs of each Technology Abatement Option

	Methane Flow rate	**0 to 15 l/s**	**15 to 50 l/s**	**50 to 150 l/s**	**150 to 400 l/s**
1	Mid Range Flow	**7.5**	**32.5**	**100**	**275**
2	CO2 potential pa/site (kt/y) at GWP 21 based on mid range flow	2.9	12.4	38.3	105.2
3	Estimated number of UK sites	N/A	9	6	6
4	% emission from each range CA, IMC and ACMMO data	5.0%	13%	30.3%	51.7%
5	Methane flow in range at total measured emission of 52kt/y (kt/y)	2.6	6.7	15.8	26.9
6	CO2e in each measured range (kt/y)	55	141	330	564
8	**Unit Cost Mitigation**				
9	Flaring (£/tCO_2e) GWP 18.25				
10	USEPA	N/A	**3.6**	**1.4**	**0.8**
11	IMC	N/A	**3.7**	**1.8**	**1.1**
12	ACMMO[1]	N/A	**8.6**	**4.2**	**2.9**
13	Generation (£/tCO_2e) GWP 21				
14	Electricity Price £26.16/MWh	N/A	**6.5**	**2.6**	**2.2**
15	Electricity Price £21.8/MWh	N/A	**7.2**	**3.4**	**3.0**
16	Electricity Price £17.44/MWh	N/A	**7.9**	**4.2**	**3.8**
17	Low REC Charge (Revenue £21.8/MWh)	N/A	N/A	**3.0**	**2.5**
18	High REC Charge (Revenue £21.8/MWh)	N/A	N/A	**6.0**	**4.9**
19					
20	Gas Upgrade (£/tCO_2e) GWP 21	N/A	**27.2**	**10.5**	**4.4**
22	**Total Cost Mitigation (Over seven years)**				
23	Flaring (£millions) - Low cost	N/A	3.6	3.2	3.0
24	- High cost		8.5	9.6	11.4
25	Generation (£millions) - Low cost	N/A	6.4	6.1	8.6
26	- High cost		7.8	13.8	19.3
27	Gas Upgrade (£millions)	N/A	26.8	24.1	17.3

Note: 1. ACMMO figures have not been verified by the authors.

3.5. Conclusions

Of the technical options for control, inhibiting flows by sealing can generally be discounted on the grounds of safety. Flaring using standard flare systems offers control where gas concentrations are above 5%. The use of gas concentrators is unlikely to encourage additional flaring.

The cost estimates suggest that flaring can be cheaper than electrical generation. For flows in excess of 150l/s the unit cost mitigation for flaring falls within the range £0.8/tCO_2e to £2.9/tCO_2e and for electricity generation within the range £2.2/tCO_2e to £4.9/tCO_2e. However, there is a wide range of estimates with the two options overlapping. The sensitivity of generation cost to REC connection charge is demonstrated by a two to three fold increase in the unit cost of mitigation between the highest and lowest REC cost. Use of CMM resources for electricity generation also presents the advantage of displacing generation capacity from large coal power plants, thus avoiding further CO2 emissions from the process. Also, the CMM industry is currently covering 40% of the estimated mitigation costs, without this industry these costs would be born elsewhere.

4. REVIEW OF EXISTING MARKET MECHANISMS

A variety of support mechanisms have been developed to encourage the use of Coal Mine Methane (CMM) and Coal Bed Methane (CBM) resources worldwide. In the context of these mechanisms CMM does not exclusively refer to methane from abandoned mines but includes or is specific to methane from active mines. The mechanisms can be categorised as follows:

- Feed-in tariffs, which provide an incentive for electricity generation;
- Obligations, which aim to legally incentivise specific market players to use specific resources by means of quotas/obligations and fines for non-compliance;
- Tax incentives, which provide investment and/or operational incentives;
- Grants, which provide capital expenditure incentives;
- Other initiatives including information dissemination programs.

A review of each category of incentives is provided below and illustrated in the context of country-specific initiatives. An attempt to identify the relative success of each scheme is provided as well as comments on the generic suitability of each scheme to project financing.

Note: The use of CBM/CMM resources in this paper essentially corresponds to electricity generation, which in itself provides environmental benefits when compared to uncontrolled methane emissions. Although some schemes may be specifically for CBM, the mechanisms could be applied to CMM schemes and are therefore included in the discussion.

4.1. Feed-in Tariffs – The Case of Germany

4.1.1. Background

The Erneuerbare Energien Gesetz (EEG) or "Renewable Energy Sources Act", implemented in 2000 by the German Federal Government, sets out the terms under which a 20-year guaranteed power off-take tariff is granted to specific renewable energy technologies. Whilst CMM is not considered as a renewable energy source, the use of CMM for electricity generation is considered to present significant environmental benefits and, as such, falls under the Act.

Electricity generated from CMM projects benefit from a pre-determined power off-take price of €76.7/MWh (£53.6/MWh) for the first 0.5MW and €66.5/MWh (£46.5/MWh) thereafter. This is significantly higher than wholesale electricity prices (c. €29/MWh) and consequently provides a strong incentive for CMM developers to capture the full potential of this energy source. The EEG also provides a legal framework aimed at facilitating the integration of such technologies to the national energy supply. This is achieved by way of:

- An obligation placed on grid operator to:
  - Connect CMM installations to their network;
  - Bear the costs of the grid upgrade costs;
- Granting priority of dispatch to electricity generated from CMM sources (ie, electricity generated from CMM installations is always exported to the national grid and always benefits from the guaranteed power off-take tariff).

The Act also states that the German government may review the terms of the EEG every two years with a view to "keeping with technological progress and market developments". The next Government review is expected in April 2004. In the current political and economic context, some believe that this review will lead to a 2% price drop applicable from 2006. All projects started before this date will continue to receive the original guaranteed fixed price for 20 years.

4.1.2. Current Status

The introduction of the EEG has been beneficial to the development CMM electricity generation projects. Before the introduction of the EEG, Germany had three operating CMM electricity generating plants with a total capacity of 6.27MW. These plants were regarded as being uneconomic and the EEG has guaranteed their continuing operation. Just under 70MW of new capacity has been added since the introduction of the EEG in Germany. The German Coal Mine Methane industry association "Interessenverband Grubengas e. V." (IVG) estimates that a further 200MW of CMM electricity generating capacity will be operational in 2004. Figure 3 below illustrates the impact of the EEG on the rate of development of CMM projects in Germany.

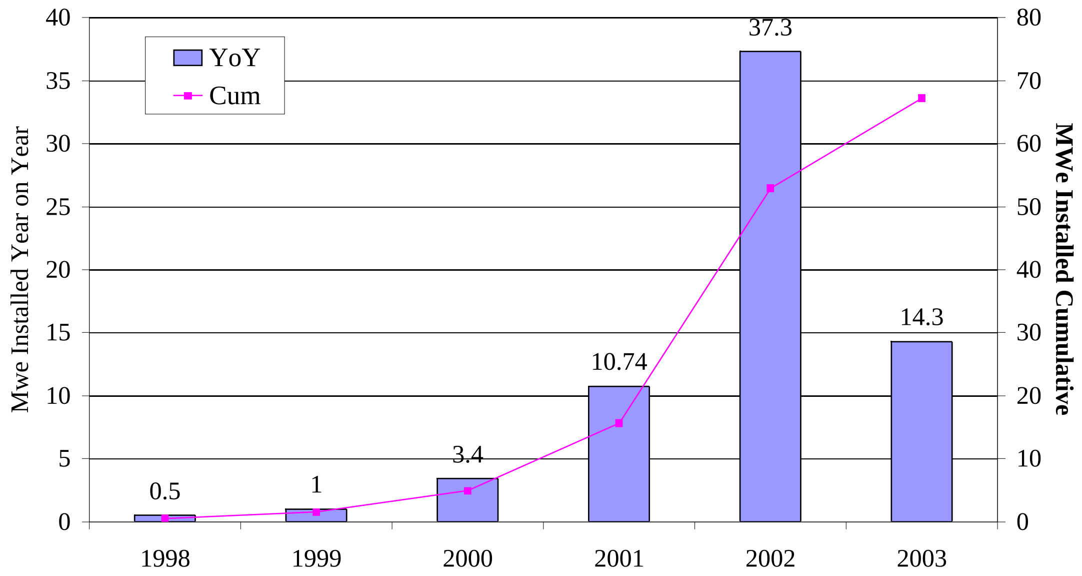

Figure 3: CMM developments under the EEG in Germany (Source: IVG)

4.1.3. Suitability for Project Finance

High-value, long-term tariffs provide an ideal support mechanism from a project finance perspective. Whilst high tariffs often make project returns attractive enough to shareholders, the 20-year power off-take guarantee provides a greater certainty over project cash flows, in turn satisfying the requirements of project finance lenders who will not want to take power trading risk.

4.2. Obligations On Energy Market Players

4.2.1. Obligation On Energy Suppliers - The Case of Queensland and New South Wales, Australia

4.2.1.1. Background

Whilst the Australian government can provide support to CBM/CMM projects by way of a 50% grant (see *4.4 Grants*) at federal level, state incentives such as the Gas Electricity Certificates (GEC) programme in the State of Queensland and Gas Abatement Credits (NGAC) in the State of New South Wales can provide additional market support to CBM/CMM schemes by way of a market obligation placed on energy suppliers.

The State of Queensland has set an objective of increasing the proportion of electricity generation from gas to 13% of total electricity generation as a move away from coal generation. Electricity suppliers are required to source GEC's from generators of electricity using natural gas, coal seam, landfill or sewage gas to comply with their obligation (in the same way as the renewables obligation in the UK). GEC's appear to be traded at just under AS$10/MWh, providing the generator with extra income on top of wholesale electricity prices.

4.2.1.2. New South Wales Greenhouse Gas Abatement Scheme

The GAC arrangement in New South Wales is somewhat similar to that in Queensland in that a demand is created by way of legislation, thus creating a market for certificates. The scheme commenced on 1 January 2003 and remains in force until 2012. Mandatory greenhouse gas benchmarks are imposed on the following parties to abate emission of greenhouse gases from electricity consumption:

- NSW electricity retailers;
- Customers with loads greater than 100GWh; and
- Parties carrying out significant state development designated by the Minister of Planning.

A state greenhouse gas benchmark of 8.65 tonnes CO_2e per capita was set for 2003 which progressively drops to 7.27 tonnes in 2007 and remains at this level until 2012. Participants in the scheme surrender NSW Gas Abatement Certificates (NGAC's) to demonstrate that they have reduced their greenhouse gas emissions. The NGAC's can be traded between other benchmark participants. At the end of each year participants submit a statement detailing their emissions and any abatement certificates held. Should there be a shortfall (i.e. the benchmark is not achieved), a penalty is due (excess emissions currently attract a penalty of AS$10.50 per tonne CO_2e. Shortfalls of up to 10% can be carried forward to the next year but must then be abated in that year otherwise the penalty is due.

Accredited parties engaged in any of the following activities can create NGAC's through a number of routes:

- Low emission generation of electricity (generation);
- Activities that result in reduced consumption of electricity (demand side abatement);
- The capture of carbon from the atmosphere in forests (carbon sequestration);

Activities carried out by elective participants that reduce on site emissions not directly related to electricity consumption.

One NGAC represents the abatement of one tonne of CO_2e. The NSW Government indicated the value of NGAC's to be in the region of AS$5 - AS$15. If a project has received funding under CGAP, the number of NGAC's created corresponds to the proportion of non-CGAP funding.

4.2.1.3. Current Status

The NSW government reports that several queries have been received from CMM and CBM developers to apply for new schemes and to accredit existing electricity generation schemes. The NSW government requires CMM/CBM projects to be associated with current mining operations and also allows large users to obtain NGAC's for the flaring of emissions from active mines.

4.2.1.4. Suitability To Project Finance

National Certificate trading schemes can indeed provide a strong incentive to technology development in the situation of high-expected demand – thus high certificate prices – and the availability of long-term power off-takes. Certificate contracts at suitable prices from creditworthy entities is however crucial to satisfying the requirements of both equity providers and project lenders. The key benefit of such support mechanism lies in its ability to provide ongoing revenues, contributing to project cash flow stability and debt repayment ability.

4.3. Tax Incentives

4.3.1. Production Tax Credits – The Case of the USA

4.3.1.1. Background

Up until September 21st 2002, the date when the scheme actually expired, US owners of wells, which produce CBM/CMM, were eligible for special taxes credit treatment under Section 29(a) the US Internal Revenue Code. The S29(a) Credit (PTC) provide a dollar-for-dollar offset to CBM generators for taxes payable under the general income tax regime. The PTC was available to CBM/CMM projects drilled by December 31st 1992 and was available for a period of 10 years from the date of project commissioning. The PTC was originally worth around US$1 per mbtu and around US$50c per mbtu towards the end of the scheme.

4.3.1.2.Current status

S29 tax credit specifically related to CMM is present in the current US draft energy bill (HR6) and we might see the renewal of the scheme in the future.

Whilst the PTC may not be the only factor behind the rate of growth that the CBM industry witnessed over the last decade, it certainly has been a contributor, which led to more than 10,000 wells being in exploitation by the end of 2000 (see Figure 4).

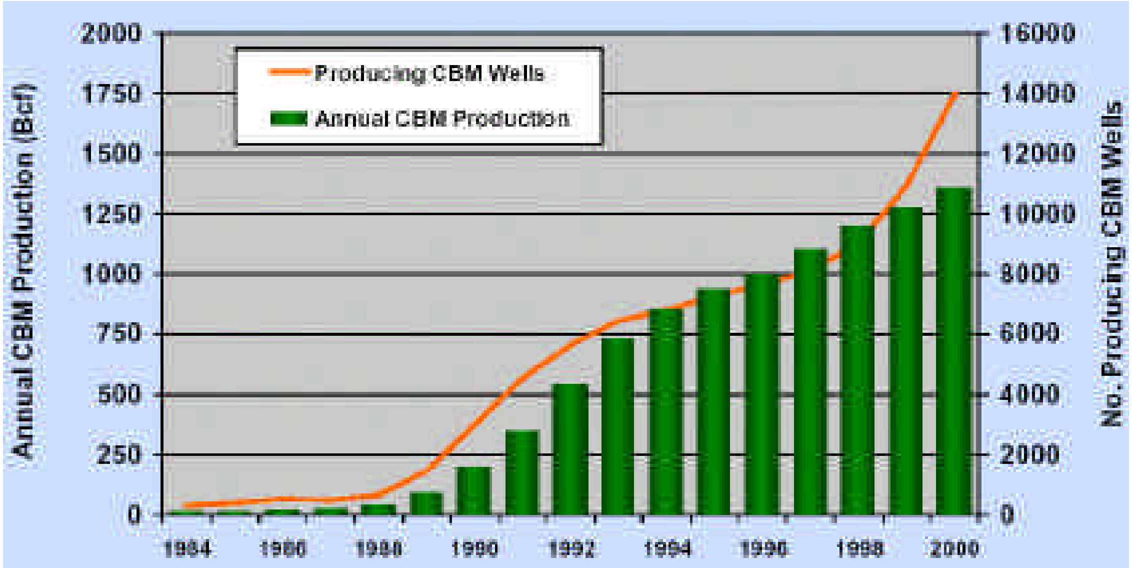

Figure 4: Producing CBM Wells and Annual CBM Production (Source: SPE, 2001)

4.3.1.2. Suitability To Project Finance

Available for a period of 10 years from project commissioning, the PTC could have proved to be an attractive source of funds for organisations with suitable taxable profits. It has proved a key driver to the growth of the wind power industry in the US over the last few years and is suitable for project finance in that it effectively acts as a revenue stream (in the same way as the Climate Change Levy does in the UK) and as such contribute to ongoing project cash flows and ability to repay project debt.

4.3.2. Carbon Change Levy Exemption – The Case of the UK

4.3.2.1. Background

On 5 December 2002 the United Kingdom notified the exemption from Climate Change Levy (CCL) charged to suppliers of electricity produced from Coal Mine Methane (CMM) from abandoned coal mines. The aim of the scheme is to incentivise the industry to develop further installations. Because of the uncertainty over the exact level of the environmental benefit from the scheme, the Government intends to hold a review of the exemption in 2004/2005. The scheme, however, is notified for a duration of five years. The aid operates by giving a tax exemption equal to a flat rate of £4.30 per MWh of electricity generation from CMM. The scheme will directly benefit the generators/suppliers of electricity derived from CMM, but the tax exemption is likely to be shared between the CMM capture company, the generating company and the end user of the electricity (where they are not one and the same).

4.3.2.2. Current Status

The scheme became effective on 1st November 2003 and its effects are yet to be assessed. The actual value of the exemption alone is, however, unlikely to make CMM developments commercially viable in the UK in the short term.

4.3.2.3. Suitability to Project Finance

The CCL exemption provides an operational incentive and is, as such, attractive. Its effect is actually anticipated to be limited as a stand-alone instrument due to the relatively low financial benefit it entails at project level. Political uncertainty associated with the possible review of the scheme in 2004/2005 may not be acceptable to project finance lenders, who may not rate this source of income post 2005 within the project cash flows.

4.4. Grants – The Case of Australia

4.4.1. Background

Capital grants, granted either automatically or by way of competitive tender, are a simple way of providing project support. This is the option that the Australian government has opted for under the Commonwealth Greenhouse Gas Abatement Program (GGAP) to encourage the mitigation of emissions from CMM from mines and the generation of electricity from this fuel.

GGAP is a key government initiative aimed at capping the country's greenhouse gas emissions to 108% of 1990 levels over the period 2008 – 2012 under the Kyoto Protocol. With AU$400m allocated to the Program, GGAP tends to support large-scale activities by way of grant support (up to 50% of Capex) through a competitive process ("Round") which selects projects on the basis of the following key criteria:

- Support is only given to activities that would otherwise not be carried out without GGAP support;
- Activities should lead to substantial emission reductions in the first commitment period under the Kyoto Protocol (2008-2012); priority is given to projects that can deliver reduction exceeding 250,000 tonnes of carbon dioxide equivalent per annum;
- Activities with a low cost per-tonne-of-CO_2 saved are favoured;
- Projects funded under GGAP are expected to provide complementary benefits (eg, opportunities for rural and regional Australia, ecologically sustainable development, employment growth, the use of new technologies and innovative processes, and non-government investment).

Grant payment is made upon achieving pre-agreed milestones.

4.4.2. Current Status

Approximately AU$145m (US$72.5m) has already been committed to support fifteen projects with a total value of AU$724m under both Round 1 & 2 of the program. Projects funded under GGAP involve capturing and burning CMM to generate electricity (and abate over 11m tonnes of greenhouse gases), and installing energy efficient electricity and heat generation units at more than ten industrial plants (and abate over 3.25m tonnes of greenhouse gases). CMM projects that have received funding are outlined in Appendix D.

4.4.3. Suitability for Project Finance

Grant funding can be a significant contributor to project economics and is often allocated to projects/technologies at the demonstration stage. However, in contrast to guaranteed power off-take contracts for instance, grants do not improve project cash flows or the certainty over project cash flows, and as such do not directly contribute to satisfying banking requirements in a project finance situation. Project finance providers therefore often assess the benefits of grant-financed projects on a case-by-case basis.

4.5. Information Dissemination – The Case of the USA-The Coalbed Methane Outreach Program (CMOP)

The Coalbed Methane Outreach Program (CMOP) is a voluntary program whose goal is to reduce methane emissions from coal mining activities. CMOP aims to promote the profitable recovery and use of CMM by providing technical assistance and disseminating information to the industry by:

(i). Evaluating CMM recovery technologies and use options and the project economics for those options;
(ii). Identifying financial mechanisms for project development;
(iii). Providing analyses to assist CMM-project developers;
(iv). Overcoming regulatory, institutional, and technological barriers to implementation;
(v). Facilitating discussion among industry participants; and
(vi). Providing project-specific technical assistance.

4.6. Relevance for the Development of a UK CMM Control Mechanism

A variety of support mechanisms have been identified to encourage the use of CBM and CMM resources by way of feed-in tariffs, tax incentives or grant support. No support mechanism was identified to support flaring or other means of controlling emissions specifically. A summary and relevance of the schemes investigated is provided in Table 4 below:

Table 4. Policies Stimulating the Control of CMM Emissions by way of CMM use (Generation)

Policy instrument	**Description**	**Country**	**Scheme status***	**Benefit to developers / suitability to project finance**
Feed-in tariff	20-year guaranteed power offtake contracts given to electricity generator	Germany	Appears very successful with c.70MW of capacity commissioned since its inception. Applied to active and abandoned mines	Very attractive due to high tariff, guaranteed for a long period of time, greatly facilitating project finance
Obligation	Obligation on energy suppliers or generators to limit CO2 emissions (Gas Abatement Scheme)	Australia	Reported to have attracted interest from the CMM industry (only active mines) which aims to accredit CMM schemes	Market-driven incentive which, if properly designed, can provide the economic impetus to developers and if structured adequately facilitates access to project finance.
Tax incentives	Production Tax Credit; a 10-year guaranteed tax-driven incentives designed to encourage electricity generation	US	Scheme not applicable anymore to CBM; however perceived to have contributed to the exploitation of more than 10,000 wells at active mines by the end of 2000	Effectively a feed-in tariff in disguise increasing certainty over level of income stream, thus facilitating project finance.
	Climate change levy	UK	Scheme introduced in 2003: limited impact today.	An incentive improving project economics, but unlikely to be sufficient on its own in the context of low wholesale electricity market in the UK
Grants	50% grant towards project costs	Australia	Five projects at active mines have already received funding, with the scheme anticipated to be fully subscribed to by end of 2004	Grants can provide a significant boost and be suitable to project finance if adequately designed.
* Note that the cost of each scheme was not investigated, being outside the scope of the Terms of Reference.				

5. POLICY OPTIONS INVESTIGATION

Section 5 presents the results of the initial investigation into the feasibility of implementing a series of policy options aimed at the control of CMM emissions from closed mines in the UK.

This Section is organised as follows:

- Section 5.1 provides an outline of the methodology followed throughout;
- Section 5.2 provides a brief description of the various policy options initially considered by the project members and identifies those perceived to offer a potentially viable mechanism in a UK context.

5.1. Methodology

An investigation of the possible policy options was initially carried out by way of workshop, which involved the identification and selection of a number of policy options in view of their suitability to a number of key principles, felt to be essential to the potential success of each option's eventual implementation. Policy options had:

- To be directly relevant to the potential technical options identified in Chapter 3, namely flaring and utilisation (electricity generation);
- To fit within boundaries of UK Energy White Paper;
- To offer a flexible incentive structure (eg, relatively easy and cheap to implement).

Note that the overall process involved close co-operation with the DTI and discussions with relevant bodies such as the trade body ACMMO (from which various resource assessments and cost data were collected), and involved preliminary discussions with the Coal Authority.

5.2. Possible Policy Options

A total of eighteen policy options were initially identified and discussed from the outset of this project. They comprise a mix of obligations, market-based incentives, tax breaks, feed-in tariffs, and direct grants/support, which may prove to be complimentary in some instances. They include:

- Extend the Enhanced Capital Allowances (ECA) scheme to CMM emissions control equipment (including flaring and electricity generation) and CMM exploration costs (Option 1);
- Use the Joint Implementation (JI) to incentivise flaring and/ or energy generation (Options 2 and 3);
- Provide direct grant for subsidising flaring and/ or utilisation (Options 4 and 5);
- Include CMM in the Renewables Obligation (Option 6);
- Place an obligation on the Coal Authority to control CMM emissions through flaring and/ or utilisation (Options 7 and 8);
- Implement a tax on polluters to support flaring and generation (Options 9 and 10);
- Use EU emissions trading system (Options 11);
- Propose tax offset to support flaring and/or generation (Options 12 to 15);
- Do nothing (Option 16);
- Implement a Feed-in Tariff (Option 17); and,
- Entry Into The UK ETS (Option 18).

5.2.1. Option 1: Enhanced Capital Allowances (ECA)

The ECA scheme provides a tax incentive encouraging energy saving investments. ECA's permit the full cost of the investment in specified technologies to be relieved for tax purposes against taxable profits of the period of the investment. Only investments in new and unused plant and machinery, defined in the Energy Technology Criteria List, can qualify.

The ECA scheme allows for 100% first-year capital allowances. With exploration costs and equipment expenses representing a significant proportion of the total Capex of a typical project, ECA's can deliver an immediate and helpful cash flow boost and a shortened payback period for organisations or projects with sufficient taxable profit. Whilst ECA's may not directly provide a strong incentive to industry players with sizeable accumulated losses, they are still considered as a "nice to have" and could be used in combination with other instruments to provide the necessary level of financial incentive. Whilst its cost would ultimately be borne by Government, this initiative, being a market-facing instrument, is perceived to fit broadly with the framework set out in the Energy White Paper and to be relatively easy and cheap to implement.

ECA's would enhance the attractiveness of an investment in the sector (at project level or else) and would therefore provide a valuable additional financial incentive (similarly to the Climate Change Levy) to projects both in the short and medium term. ECA's are also anticipated to have minimum additional administrative and legal requirements. ECA's would benefit projects and any eventual operators or investors through adequate tax structuring.

5.2.2. Options 2 and 3: Use the Joint Implementation (JI) to Incentivise Flaring/ Energy Generation

Joint Implementation (JI) is one of the project-based mechanisms under the Kyoto Protocol, offering an entry route for low cost abatement opportunities to contribute to emissions trading systems and obligations under Kyoto to ensure economic efficiency. The mechanism is directly in line with the Energy White Paper, where it sees emission trading as the primary mechanism to control GHG emissions.

JI may operate under a number of different conditions which are set out as part of a more comprehensive discussion in Appendix E. The mechanism offers project developers the opportunity to reduce emissions outside the capped sectors of the economy (sectors not covered by current polices, measures or obligations). Such emissions are rewarded with the allocation of Emission Reduction Units (ERU's) or 'Carbon Credits'. These credits are tradable commodity instruments that have a value in tradable, compliance-based markets. Subsequently they offer developers effective payment for the provision of environmental services (in this case the reduction of GHG emissions).

Payment streams are received by trading the credits after the emission reduction has been achieved, and in the case of JI, payment will often be received from a foreign counter party. JI is in line with current UK policy, and offers a route to finance activities. However, a number of issues may preclude JI from being a viable option in the short-term (see Appendix E).

A summary of emissions trading as a route to control covering both JI and EU ETS is given in Section 5.2.12.

5.2.3. Options 4 and 5: Provide Direct Grant for Subsidising Flaring and/ or Utilisation

The Australian grant funding initiative (described in Section 4.2) appears reasonably successful and a similar scheme could be launched in the UK. A UK fund, primarily designed to support the control of CMM emissions, could be created to that aim and funded out of new taxation measures (on polluters, see those envisaged in Section 5.2.6) or the reallocation of existing funds or tax resources (see those envisaged in Section 5.2.8).

The fund could be allocated through a "CMM emissions control grant programme" designed to support flaring projects and, where economically viable, the use of methane for electricity generation. Grants assisting the industry during the early stages of project development (eg, drilling and preliminary investigations) could also be envisaged. Grants could be allocated by way of tenders/calls for proposals and organisations such the Carbon Trust, who are recognised for their technical expertise, could take charge of administrating the fund under its Carbon Management Initiative. A streamlined process – with limited application requirements, a quick turnaround and limited 'conditions' sometimes complicating the sourcing of additional financing[1] – would need to be considered to ensure scheme success and industry support. In view of the limited potential (and the relatively small number of realisable projects), the scheme could also be tailored to support a series of demonstration projects allowing the economics of projects to be tested and any eventual technical challenges assessed.

Grant funding through existing administration infrastructure has the ability to mobilise capital relatively quickly and the opportunity to be tailored to support either flaring and/ or generation in a flexible manner (ie, where economically feasible). While not always positively perceived within industry, a Government-backed grant program may be a realistic and useful short-term solution if efficiently designed and implemented.

Grant funding could be allocated on the basis of call for tenders asking bidders to specify the amount of funding required to achieve a target £/CO_2 emissions avoided figure (possibly initially set by the government, which could eventually benefit from the carbon benefits generated by any such project). The payment of such grant benefits would have to be such that it satisfies project-financing requirements. The grant benefits may therefore be allocated as, possibly, a combination of the payment mechanisms described in Table 5 below.

[1] One example is a stipulation by the grant giving agencies that successful applicants provide bank guarantees to cover the grant provided. If a grant system is to be designed to support activities involving private sector companies then consideration of how the grant system interacts with project financing has to be taken into account.

Table 5: Possible grant payment mechanisms and implications

Possible grant payment mechanisms	Implications for project financing		
	Flaring	Generation	Comments
A one off payment made on project commissioning*	Payment would have to cover the full costs of the project, including O&M, and any additional profit margin (should this require the private sector) on day one	Payment would have to be significant enough so that it reduces debt requirement to the extend that revenues on their own can guarantee debt repayment	The government would bear all the project risks, without real guarantees for delivery.
A series of payments**	Such payments would have to be designed so that the project economics and cash flow situation can sustain any eventual debt repayment		Likely to vary on a project-by-project basis
	Grant set at a level such that flaring is supported	Grant set at a higher level than flaring so as to encourage utilisation of CMM (?)	
* Calculated on the basis of a project IRR ** Possibly directly linked to amount of carbon saved; this would effectively equate to the government buying carbon credits, through the accumulation of AAUs (and could be structured in the same way as NFFO contracts); this would also require agreement on the measurement and validation of exact amounts of CO_2 saved.			

Clearly a realistic grant payment mechanism is likely to involve a series of payments made on delivery of services, which protects the government from taking all of the project risks. Allocation of grant finance to existing projects, which might currently be encountering financial difficulties, should also be considered as a priority in order to sustain CMM management. Additional investigation with regards to identifying those sites, which would best benefit from this scheme, may also be required. Whilst grants have not been traditionally perceived well in industry as a result of their bureaucratic and cumbersome implementation, the very focussed nature of a grant scheme designed specifically to control CMM emissions should surely contribute to a streamlined, and easily accessible and managed programme.

5.2.4. Option 6: Include CMM in the Renewable Obligation (RO)

The Renewable Obligation, which places an obligation on electricity suppliers to source an increasing proportion of electricity they supply from renewable energy sources, is the main market driver to promote the use of renewable energy resources in the UK. It can provide significant premium prices to renewable energy generators, which might otherwise be uncompetitive in the UK power market.

The RO has a number of benefits in terms of the key features of the mechanism, including the significant potential to attract project finance (for generation), long term supply contracts, simple monitoring process (if the assumption that all gas captured is additional- and none is accelerated), and limited management overhead and cost to Government.

RO was specifically designed solely to support renewable energy sources. Germany, recognising the environmental benefits associated with the generation of electricity from CMM, opted for the inclusion of CMM under the EEG. However, in line with the EC Directive 2001/77/EC, neither Germany nor the UK consider CMM as a renewable energy source, since CMM is derived from coal seams and coal is a non renewable energy source. Consequently, it was confirmed by the DTI that the inclusion of CMM in the RO was inconsistent with Government Policy.

5.2.5. Options 7 and 8: Place an Obligation on the Coal Authority to Control CMM Emissions

An obligation on the Coal Authority to control emissions by way of flaring (Option 7) or, where feasible, by way of generation (Option 8), could also be envisaged to fulfil specific pre-determined emissions reduction objectives set to be attained within a specific time period (say, by a certain date or annually).

The Coal Authority could choose to deal with this obligation either independently, allocating adequate budget and resources, or rely on the involvement of the private sector using a variety of mechanisms which could include grant funding or the guarantee of revenues reflecting the amount of emission control achieved through flaring or generation (itself possibly benefiting from an extra level of funding in recognition for the extra environmental benefits associated with the activity).

An obligation on the Coal Authority where the involvement of the private sector would be sought may provide the right mix of government management control over the control of CMM emissions (for, say, health and safety reasons) and private sector involvement in view of technical resources mobilisation and ability to develop, own and operate such flaring and/ or generation projects. Such partnership may allow the government to transfer risk of delivering emissions control to the private sector in return for an appropriate remuneration. The approach taken could be similar to the basis upon PFI initiatives are place in with the private sector, with payments for achievement of pre-agreed milestones.

A possible procedure could involve the Coal Authority letting a contract under EU procurement rules on a project by project basis or for a block of projects whereby bids are selected on the payment required by the private sector to generate electricity from a particular site for a period. Such contracts would be long-term to allow project financing and could make the sharing of upside benefits with the Coal Authority should a radical upward shift in power prices occur. If an acceptable bid is received, then the CA would contract that entity or consortia to do the work; if no bid is received or where the generation bid does not suit the cost targets envisaged by the Coal Authority, then flaring would be considered. Flaring may be considered for projects where generation may not be considered feasible. For each project a total economic cost appraisal (ie. net present cost of projected project costs and net present costs of risk retained by the government under both options) would establish whether a private sector solution, incurring a risk-adjusted return of say 11 to 13% is better value for money than that of a public sector option after taking into consideration the value of risks retained by the public sector under a government-lead and funded procurement approach.

At present the Coal Authority has a duty to control emissions in situations where a health and safety hazard or nuisance is perceived. An extension of the Coal Authority’s role would therefore be required to take on a wider role associated with the control of CMM emissions. The Authority considers that its powers are drawn widely enough to include methane control on a similar basis to minewater. For the Coal Authority the fundamental requirement for taking on environmental obligations of methane emissions is that it should be properly funded and resourced by the Government with recognition that environmental methane emission control features alongside minewater as a primary operational function. Whilst this option presents certain challenges in terms of funding, which would ultimately have to be sourced from government funds and/ or additional taxes, such obligation would make use of existing administration infrastructure (and would be as such relatively quick and cheap to implement), would provide the flexibility of choosing the most suitable technical option (flaring or generation) on a project-by-project basis, and would also provide emissions control within a limited period of time.

The Coal Authority has stated that it wishes strongly to encourage the CMM industry. This fits in well with its Coal Bed Methane duty under 3(5) of the Coal Industry Act 1994 (CIA) where the Authority is to have regard to the exploitation of coal bed methane. Coal mine methane could be covered by the same principle and the authority’s current policy is to encourage CMM development.

This option clearly requires further consultation with the Coal Authority, current PEDL license holders, the industry and the DTI itself. A much clearer idea of the exact CMM resource potential and where generation / flaring / venting are likely to be the preferred options would also need to be provided. The risk transfer to the private sector – and the costs that this is likely to involve – also ought to be investigated, together with the practicalities of insuring the participation of current PEDL licence holders.

5.2.6. Options 9 and 10: Implement a Tax on Polluters to Support Flaring and Generation

5.2.6.1. Option 9 - Venting/ Flaring Tax

In line with the principle of the polluter pays, a venting/flaring tax could be developed as a means of incentivising the control of emissions from CMM. In the UK, the polluter is effectively the government, as the former mine owner/operator through British Coal. Whilst petroleum licenses confer rights to capture gas from CMM, the liability in respects of emissions remains with the government through the Coal Authority.

The tax could be designed so that the penalty is greater for venting than for flaring and made nil for CMM electricity generation to reflect the respective environmental benefits of each technical solution. This would effectively equate to a carbon tax, however solely placed on CMM, the receipts of which would be re-invested by way of grant of some sort into CMM projects. Whilst the principle of funding a grant program through existing or additional tax revenues remains valid, a venting/ flaring tax would create additional burden to the economy and would not, on its own, lead to emissions control.

5.2.6.2. Option 10 - Tax On Newly Closed Coal Mines

In line with Government policy on aggregate extraction, a new tax on newly closed coal mines could be envisaged. This would be designed to ensure sufficient finance for remediation of legacy issues, with the receipts allocated towards the control of CMM emissions by way of grants.

Whilst the principle of allocating tax revenues towards CMM emissions control activities remains valid, many of the colliery closures that have taken place have been from companies in receivership/liquidation. In practice this option would most likely be funded out of government funds, which are also often requested to manage mine closure.

5.2.7. Option 11: Use EU Emissions Trading System

One of the most significant policy instruments designed to meet UK and European GHG reduction targets is the EU Emissions Trading System (ETS). As currently designed, the EU ETS would only cover emitters of GHG's and not allow an entry route to emission trading to those capturing fugitive emissions not of their responsibility.

The EU ETS, covering the power sector, would provide an indirect driver. This would occur both as a result of expected uplift in electricity price, and an additional incentive for electricity generators to use CMM gas and reduce their own production at capped installations.

The ETS entails two phases:

- Phase 1- 2005-7: The first phase of the EU ETS only deals with reductions in CO_2 emissions in the period 2005-7, and as such will definitely not provide a direct incentive route to reduce CMM.
- Phase 2- 2008-12: The second phase EU ETS may offer some scope to CMM control operations. However under the EU ETS directive, even with the ability to voluntarily opt in certain economic sectors or installations, and different (non CO_2) gases, significant barriers will exist. These barriers exist because (as previously mentioned) the EU ETS is designed to manage primarily large emitters. In addition, issues such as the allocation methodology, monitoring and verification etc will affect entry. Indeed the accounting of CMM as a natural gas under EU ETS has the potential to have the opposite effect of incentivising CMM control, as a number of current CMM capture and use sites in the UK will fall under the thresholds of the EU ETS. Consequently an additional burden may be placed on CMM use through this mechanism where sites exceed a certain size.

The EU ETS is a mechanism that is considered by the UK Government to support CMM emissions control in the Energy White Paper. EU ETS is thus very much in line with government policy, and, given the value expected of EU allowances in the Commission's models (in the order of €12-14 per tonne of CO_2), it appears to offer a great deal of potential for financing the control of CMM emissions at first glance. However, its applicability, anticipated not earlier than 2008, offers little in the short term. EU ETS could however offer a low cost, low effort (assuming CMM eligibility) route to CMM control if enough effort in ensuring EU ETS entry were applied.

A summary of emissions trading as a route to control covering both JI and EU ETS is given in Section 5.2.12.

5.2.8. Options 12 to 15: Propose Tax Offset to Support Flaring and/ or Generation

5.2.8.1. Options 12 and 13: Climate Change Levy (CCL) Offset for Flaring and Generation

A mechanism incentivising large energy consumers liable to 80% of the CCL to contract CMM emission reduction initiatives could also be envisaged. This would entail the creation of a framework between large energy users and CMM developers whereby large energy users would benefit from a reduction in CCL payments provided investments are made in CMM emission reduction initiatives. Such contracts would bi-lateral and designed so that they can be in place for medium to long periods of time (say, 10 years), thus contributing to project financiability. The tax rebate structure would be designed so that greater incentive is provided for electricity generation-related investments in recognition for the additional environmental benefits it provides.

5.2.8.2. Options 14 and 15 - Petroleum Revenue Tax Offset for Flaring and Generation

The Petroleum Revenue Tax is a field-based tax corresponding to 50% of the market value of the oil or gas extracted from a UK field. The PRT was abolished for all fields given development consent on or after 16 March 1993 and many taxable fields do not pay PRT because of the various relieves available. However, PRT is still levied and a policy could be designed so that investments from PRT taxable organisations in CMM emissions control projects can benefit from a specific relief under PRT. This could mean that any Pound invested in a flaring project would benefit from, say, two Pounds relief from the PRT, and, say, three Pounds relief when invested in CMM electricity generation projects.

However, the applicability of these mechanisms would be complicated (possibly requiring specific approvals by the European Commission in relation to State Aids Rules) and limited in scope in view of the burden (time and effort, negotiations, etc.) it would place on these large organisations (large energy users and petroleum companies) compared to the actual benefit it could bring them.

5.2.9. Option 16: 'Do Nothing'

The do nothing option requires no action, involves no costs (at least direct), and allows CMM emissions to continue unabated in the knowledge that their effect over time they will diminish. It is however directly opposed to the Energy White Paper in which the government stated its intention to work towards a more effective emissions control. In a situation where CMM emissions are included in the inventory, a direct opportunity cost exists in the order of an estimated £1.3-5m pa[2]. There is a very real opportunity cost to this option[3], in that it does not materially impact on CMM emissions.

Future social costs of emissions are also associated with the do nothing approach. Government Economic Service Working Paper 140 from the DTI states that the most sophisticated of the published studies on social costs of methane emissions produces an estimate of the marginal damage figure of approximately £70/tC (£19/tCO_2) rising at a rate of £1/tC per year. However, there is a large uncertainty attached to such calculations at the Paper suggests an upper value of £140/tC and a lower value of £35/tC.

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[2] This may be quantified by determining the future value of the surplus Assigned Amount Units (AAU's) available to Government should CMM emissions be abated. At today's prices in the order of €3-5 per AAU may be ascribed to AAU's. A future value (during 2008-12) could actually be closer to €8-12 given the expected uplift in value of this commodity nearer the commitment period. IMC are currently estimating that some 30kt of fugitive CMM is being produced and not mitigated (equivalent to around 0.63m tonnes CO_2 pa), the opportunity cost through lost AAU's could be between:

- €1.9-3.1m pa at today's value & €5.0-7.6m pa at potential future values.

In addition, if control were to cease at any of the sites currently managing CMM emissions could rise as 1.1mt CO_2e, (53kt CMM) with an opportunity cost of:

- €3.3- 5.5m pa at today's value & €8.8- 13.2m pa at potential future values.

This assessment also ignores other benefits that may or not accrue from mitigation (included free energy production and contribution to GDP or avoided damage costs).

[3] This assumption is premised of course on the fact that CMM emissions should ultimately enter national inventories- an issue that is due to be reviewed by the Inter-governmental Panel on Climate Change in the very near future. Such inclusion is one of the prime driving factors behind the DEFRA work on UK CMM emissions currently ongoing.

5.2.10. Option 17: Implement a Feed-in Tariff

Similar to the German model (EEG), a feed-in tariff could be implemented in the UK whereby gas and/or electricity utilities would have an obligation to purchase all units of gas and electricity available from CMM plants at a fixed price. Such power off-take, to be attractive to both the industry and project financiers, would need to be relatively attractive and guaranteed for a medium to long-term period (say, minimum 10 years).

Whilst such policy is likely to receive the support of the industry, it is unlikely to be in line with the government Energy White Paper, which aims to “promote competitive markets”. Such policy mechanism would also require a new Obligation to be placed on energy suppliers, and this was perceived to be relatively costly to implement (ie, not using current institutional infrastructure) and possibly long to implement.

A hybrid version of a feed-in tariff could be envisaged by way of an obligation placed on the Coal Authority (see Section 5.2.5.) where long-term (power offtake) contracts are awarded to the private sector for the provision of CMM emissions control services (possibly by way of generation). This would stimulate the industry and facilitate project financing.

5.2.11. Option 18: Entry Into The UK ETS

While one option offered through the Energy White Paper was entry to the UK ETS through a projects based route, this does not offer a realistic alternative as the UK projects work-stream has effectively been abandoned.

5.2.12. A Summary of Emissions Trading as a Route to Control.

The previous discussion assesses a number of potential entry routes to control CMM through emission trading related mechanisms. The assessment indicated that these are currently unavailable as a medium term option. This does not mean they should be discounted as options altogether. Subject to resolution of a number of issues discussed in more detail below, any immediate control mechanism implemented could migrate to a more medium term focussed trading based regime and preparations need to be implanted now in order to achieve this. Two realistic entry routes to trading have been identified here, the first the EU ETS (option 11) and the second Joint Implementation (option 2/3- see also Appendix E). Both face very similar issues in relation to their ability to contribute to CMM control.

Some of the most significant issues affecting the efficacy of trading mechanisms may ultimately be resolved over time scales similar to the characterisation of the full CMM problem under the DEFRA work, and hence the characterisation as a medium term option. Controlling CMM emissions through JI projects and the EU ETS could potentially be cost efficient[4] for Government and could potentially encourage the use of CMM resources, and provide the entry route into trading that the White Paper favours. It would however be lengthy to implement, especially given the uncertainties of the mechanism itself in relation to the Kyoto Protocol. Nor would it be without additional administrative burden for DEFRA and the DTI, although this could be somewhat mitigated by the existence of the UK Climate Change Projects Office (CCPO).

[4] As the cost is not borne directly by Government, and in the case of JI will see finance sourced outside the UK.

How the mechanism will operate is not discussed in detail here, rather barriers to its utility are addressed. However, it is important to note that trading can operate in two modes that will have an impact on financing control operations:

- **Cap and Trade:** The EU ETS is a cap and trade mechanism that sees allowances allocated that are immediately tradable, with verification and reconciliation of allowances and emissions at the end of the trading period. Current expected prices for EU Allowances are in the range of €12-14, with trades in the order of €10-12 already being observed in the grey market;
- **Baseline and Credit:** JI is a baseline and credit mechanism, with allocation of ERU's made at the end of the period in question, post any verification of results. Hence the ERU's are not immediately available, and may not be so until issued- something that can see in excess of a 12-15 month delay in relation to availability vs. the cap and trade route. Current prices of ERU's are in the range €3-5, with some uplift expected, but not guaranteed.

Given the issues identified below in relation to trading mechanisms, and why CMM is unable to find an entry route immediately, it is clear that JI offers the more immediate opportunity as opposed to EU trading. However, EU ETS, in the longer term, is more aligned with White Paper policy, offers more value (potentially) to mobilise action and quicker. Therefore, the long term goal should be to attempt to secure entry into the EU ETS.

Factors negatively affecting trading as a control mechanism that require resolution include[5]:

- Characterisation of scope and scale of CMM emissions from sources not currently known;
- Inclusion in the national inventory;
- Quantification protocols and methodologies for baseline determination;
- Treatment of acceleration;
- Political uncertainty affecting market development and price;
- Ability to finance (trading becomes bankable as a financing mechanism);
- Political & technical acceptability as to inclusion of CMM in the various mechanisms (domestic projects, JI, EU ETS);

There is currently limited operational experience in international carbon trading. However, as these technical, political and pricing & financial uncertainties are resolved over time, it may become clear that trading mechanisms may offer a great deal more to control CMM emissions. In order to operationalise a trading option in the medium term, Government must make significant decisions to mitigate the risk factors above. For example, should CMM emission be controlled through use of JI, the following risks can be transfer to Government and away from the project developer, or removed altogether:

[5] On the whole, these issues are potentially the same technical and political issues facing EU ETS entry as well

Political Risk Factors	Control Option
· *Characterisation of scope and scale of CMM emissions from sources not currently known*	· Continue with work to characterise UK CMM emissions
· *Inclusion in the national inventory*	· Include in the National Inventory ASAP
Technical Risk Factors	***Control Option***
· *Quantification protocols and methodologies for baseline determination*	· Follow a track 1 JI process (or alternatively Article 17 trading route)
· *Treatment of acceleration*	· Set out immediately methodologies and quantification protocols
· *Political & technical acceptability as to inclusion of CMM under JI*	· Assume time value of gas captured is zero- accept all gas captured is additional
Financial Risk Factors	***Control Option***
· *Political uncertainty affecting market development and price*[6] · *Ability to finance (trading becomes bankable as a financing mechanism)*	· Government guarantees delivery of ERU's to buyer · Government facilitates up front, or early payments, from ERU purchaser · Government backstop guarantees payment of ERU buyers financial flows (Gov carries Kyoto entry into force risk)

Clearly, these are significant political decisions, and potentially decisions that will not be able to be made in the near term. Even more significant issues may be observed if the EU ETS is seen as the instrument of choice, as decisions that may be required to be taken may not be within the gift of the UK Government alone to grant, the EU ETS being an internationally negotiated mechanism, with little scope of individual Member State decision making.

Despite their inherent benefits and suitability to the Energy White Paper, both JI and EU ETS options are effectively precluded from being implemented in the short term. They may however, subject to international policy developments, prove to be an option in the medium term.

[6] Recent issues linked to Kyoto entry into force have seen many commentators place a high risk on JI as a result of Russia's potential future decision making.

6. NON MARKET BARRIERS

There are significant non-market barriers that restrict the development of CMM projects, many of which have been identified in the Energy White Paper, albeit in reference to renewable resources.

6.1. Land Ownership

Many of the abandoned mine sites, where venting occurs or where suitable sites (mine shafts or drifts) exist, are owned within the public sector by Regional Development Agencies (RDA's), Local Authorities (LA's) and the Coal Authority. Of these bodies only the Coal Authority has a published commitment to aid the utilisation of mine gas. The re-development of the abandoned mine sites carried out by RDA's may make provision for utilisation (e.g. Allerton Bywater), but more often utilisation may actively be prevented (e.g. Cronton). Moreover, even in the case of venting for safety, the Coal Authority has no powers to occupy land, including land in public ownership. Hence, gas may be discharged in an uncontrolled manner for considerable time until land for a suitable vent may be found. Even where the Coal Authority takes occupation of abandoned shafts for venting, the area occupied is not generally sufficient for the mitigation by flaring or other means.

Delays in obtaining access to the gas in the abandoned mine can have considerable financial and environmental consequences due to the limited life associated with abandoned mine methane. A year's delay represents a year's gas lost to the atmosphere. It is also a potential loss of income for any commercial user that cannot be recovered later due to the limited life of the gas source. The problem is compounded by the fact that emissions tend to decrease with time. Gas lost in years immediately following closure tends to be greater than in later years.

Where land is under private ownership, anecdotal evidence suggests that ACMMO members pay landowners a much higher price than the Coal Authority for similar borehole drilling rights.

The barrier is likely to most affect colliery sites closed in future where the site will be redeveloped. RDA's and LA's could be directed, as part of their environmental objectives, to support and encourage any development controlling mine gas emissions within their portfolios.

6.2. Planning Consents

Planning consents may be similar for controlling emissions on safety grounds (Coal Authority) as those required by CMM operators. The planning process, involving each tier of local government, is a lengthy procedure. One planning application by the Coal Authority took almost four years to resolve. The experience within ACMMO is that the process can take from 3 to 19 months, with 5 to 8 months being typical. The effect of such delays has been described above. As an example, Strata Gas were severely affected by problems in obtaining planning permission. Strata Gas were seeking permission to sink a CBM well, but a similar position could easily arise with permissions to extract gas from abandoned coal mines. Strata Gas used all their development capital to obtain the planning permission, effectively leaving them unable to finance the project or any other in future.

Furthermore there is evidence that applications can be dealt with quickly. One Coal Authority application for the drilling of boreholes was dealt with under the General Development Licence (GDO) (allowing drilling to be carried out within 28 days) but a further application, to the same authority, required full planning procedure. A consistent approach is required.

Difficulties in obtaining planning consent are likely to be faced not only by PEDL holders, but also by renewable energy project applications. At present there is likely to be delay in implementation of environmentally beneficial schemes such as renewable energy projects and the control of coal mine methane emissions. Action to reduce delay could be beneficial to schemes needed to mitigate the emissions from those active mines that are projected to close in the next decade. However, any direction to streamline the planning process for such applications would have to come from Government.

6.3. REC Connection

Where gas from abandoned mines is used to generate electricity, the electricity must be exported from the site to the electrical system of the local electricity operator who owns the local wires business. The costs and time taken for this process creates a considerable barrier, identified by the Energy White Paper (in the case of all distributed generation). The experience from existing sites indicates that costs can be as high as £2M for the connection and the cost is unrelated to power input. On average the cost per connection is in the region of £500,000. The process typically takes up to 12 months to get a connection feasibility study done and is reported to be the slowest part of a CMM development. The connection itself will also have a long lead time, which has in the past been as long as 18 months.

The process of obtaining a REC connection is cumbersome, requiring the applicant to ask a specific question for a fee (eg what is the cost of connecting a 5MW generating station at X to the network). The response (within a statutory 3 month period) answers the specific question which, if identifying prohibitive costs, may prompt a further question regarding costs of an alternative connection.

The process could be much more transparent, with the REC making available details of the capacity of branches within its network. Alternatively, a sliding scale for connection charge, proportional to the output of the distributed generator, could be introduced. However, the use of a sliding scale would carry financial risks for a REC. The problem is addressed in the Energy White Paper and is one shared by all distributed generators. This is a significant time and resource barrier that dramatically affects project lead times and costs/viability

6.4. Licensing

Currently, coal mine operators extract or vent methane under a Methane Drainage Licence (MDL) that does not discriminate between a mine in use or disused. Coal mine operators have a MDL for each mine. Coal Mine Methane operators require a PEDL for blocks based on OS grid lines and are purchased from the DTI by means of a competitive tender. The use of grid lines has caused difficulties for PEDL holders where abandoned mine workings span different blocks held by different companies or where gas is vented in one block separate from the block holding the reserves (eg Parkside).

The Coal Authority operates with a venting licence that covers the whole of the UK but it is unclear whether this would allow flaring or utilisation. The Coal Authority currently only vents the gas and its policy is to encourage CMM development. Consequently, the Authority will co-operate with the PEDL holder to allow them to utilise the gas. The basis on which the MDL's are operated is different, since the mine operators are able to utilise or flare the gas and gain income directly through power exports and/or in power savings, as well as with carbon credits (UK ETS). As a result, mine operators can gain benefits from utilising or flaring gas from a closed mine which PEDL owners could not. While coal mine operators can make income from a closed mine in this fashion, they are unlikely to relinquish the mine back to the Coal Authority. It is understood that the Coal Authority and the DTI have had preliminary discussions regarding the ability of a mine operator with an MDL to be able to continue to use the licence on closure where the safety of the mine or public safety was at risk. Conversely, where no safety issues exist the PEDL holder could be given the opportunity to take over the methane discharge under their own licence. In the event that the PEDL holder does not wish to take over the discharge the mine operator could be assigned the PEDL.

To facilitate the mitigation of CMM emissions an obligation could be placed on licence holders to utilise or flare vented flows or relinquish their licence. Where venting sites were installed post the granting of a PEDL the Coal Authority would be responsible for mitigation unless the PEDL holder accepted responsibility for mitigation.

If the CMM industry is to be encouraged, clarification of the rights granted by the respective licences is required. Where the Coal Authority proposes mitigation schemes the PEDL holder could be offered the opportunity to use or flare the gas. Should the PEDL holder not wish to do so the Coal Authority would then be able to offer the work to others in a manner similar to minewater treatment schemes. The conflict between the rights of holders of MDL's and PEDL's appears to have already been determined, although the question of risks to public safety is likely to be subjective. A more objective approach would be for MDL holders to pay a royalty to the existing PEDL holder (a scheme similar to the fee paid to the Coal Authority by the mine operator for the extraction of coal). However, whereas in the case of coal the Coal Authority is the owner the PEDL holder does not own the gas until the holder captures the gas. Therefore, royalties for gas would require a change in the licence agreement, transferring ownership at an earlier stage, or a means of applying a value to the licence which could be used as a basis for calculating royalty payments. New PEDL's could be granted on the understanding that gas extracted solely from mines abandoned in the future would be excluded from the licence. However, unless the future closed mine is isolated the question of which workings contribute to the gas emitted remains. This problem is similar to that of reserves crossing licence boundaries and both may need to be settled by arbitration.

PEDL licence fees are paid and obligations accepted on the basis that there may be some financial benefit arising from the collection of the gas. However, ACMMO state that under the present economic climate this is not the case. There could therefore be a case for suspension of PEDL fees and obligations until such time as the economic position improves. This could either be done unilaterally by the DTI or some compromise adopted through negotiation with the PEDL owners.

6.5. Coal Authority

The Authority is currently preparing to spend an estimated £300,000 on a gas pumping station at Barnsley to drain gas from a sandstone that acts as a pathway for gas from abandoned workings to migrate to the surface. The pumping station is designed to extract up to 500l/s (not continuously) of abandoned mine gas, all of which will be discharged into the atmosphere. Further investigations could lead to the location of the gas source and enable the gas to be commercially utilised rather than emitted directly to the atmosphere.

Where significant funds are to be spent by the Authority on gas control measures for safety any evaluation could include the alternative of entering into contracts with the PEDL holders to control the gas on their behalf in return for economic support (Section 5).

6.6. Abandonment of Collieries.

As outlined in Section 2.2, any delay in applying control measures following closure of the colliery will lead to large uncontrolled emissions to the atmosphere and potential loss of income from commercial utilisation. The closure of the colliery will require close involvement between the colliery operator, the Coal Authority, the PEDL owners and any bodies redeveloping the site. Planning for closure is required at an early stage to ensure that measures can be put in place on closure. The Coal Authority may be in the best position with respect to the other parties to act to direct the closure to ensure emissions are controlled. At present the Coal Authority has powers to insist on measures to control gas for public safety but not for mitigation by flaring or generation. Mitigation measures could be included as a requirement on abandonment either through the Coal Authority or Environment Agency, subject to the appropriate powers being made available.

In general, to enable control of emissions, once mining finishes, sealing of the mine should be completed as soon as possible. Suitable pipework should be installed in the filled mine entry to enable the controlled release of the gas. If the PEDL owner cannot or will not use the gas then the Coal Authority could act to either seal the mine against emissions if it is an isolated unit or arrange to flare or utilise the gas being released. Where multiple connected collieries are to be closed progressively benefit would be gained by each colliery being dealt with independently as far as gas emissions were concerned. For example, at Selby, progressive closure of collieries without providing venting/collection pipework at the shafts or interconnections would lead to the collieries' high initial emissions, being emitted to atmosphere via into the operating mines, rather than being amenable to control at the crucial time.

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