Development of a techno-economic model for coal bed methane production and electricity generation from deep virgin coal seams

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Abstract

The development of a techno-economic model to investigate the economic potential for recovering methane from virgin coal seams for electricity production at a study area in South Wales, UK, is presented. Utilizing the coal bed methane gas to fuel a combined cycle gas turbine (CCGT) will offer a low carbon option compared to fossil fuel fired power generation for a study area in South Wales. Cost effectiveness is analysed using a techno-economic model developed specifically for this purpose. The model considers both reservoir conditions and engineering factors to calculate the enhanced ultimate recovery (EUR), the capital expenditure (CAPEX) and the operational expenditure (OPEX) of the coupled CBM-CCGT process at the study area. The projected UK Navigant gas prices and the DECC electricity prices are then used to estimate the levelised costs of electricity (LCOE) and obtain the financial performance of the coupled CBM-CCGT process. Calculation results showed that the probable cost of electricity (LCOE) amounts to 37 £/MWh and the return on investment could be in the excess of 77%. For the selected study area, the coupled CBM-CCGT process could potentially be an economic option for power generation.

Keywords: *Techno-economic model, Coal bed Methane (CBM), Electricity generation, Cost of electricity (COE), South Wales Coalfield.*

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Abbreviations/symbols

q_o:	Initial production
q_t:	Production rate
£:	English Pounds
£m:	Million English Pounds
A:	Area
CAPEX:	Capital Expenditure
CBM:	Coal Bed Methane
CC:	Carbon cost
CCGT:	Combined Cycle Gas Turbine
CF:	Cash flow
CoI:	Cost of Investment
COE:	Cost of Electricity
d:	Days
DECC:	Department of Energy and Climate Change in UK
DR:	Discount Rate
DTI:	Department for Trade and Industry
E:	Percent of Efficiency
EG:	Electricity Generation
EIA:	Environmental Impact Assessment
EUR:	Estimated Ultimate Recovery
G_c:	Gas content of the coal
GCP:	Gas Collection Point
GCP:	Gas Collection Point
GCU:	Gas Compression Unit
GfI:	Gain from Investment
GP:	Gas produced
GSU:	Gas Storage Unit
h:	Cumulative height of coal
hr:	hours
km^2:	square kilometres

LCOE:	Levelised Cost of Electricity
LR:	Loss ratio
m:	meters
mD:	millidarcy
MW:	Megawatt
MWhr:	Megawatt hour
n:	Time period
NEG:	Net Electricity Generation
NG:	National Grid
NPV:	Net Present Value
OGIP:	Original Gas in Place
OPEX:	Operational Expenditure
OC:	Outgoing costs
P10:	90% probability of meeting or exceeding the estimated proved volume
P50:	50% probability of meeting or exceeding the estimated probable volume
P90:	10% probability of meeting or exceeding the estimated possible volume
PEDL:	Petroleum Exploration and Development Licences
R:	Revenues
RF:	Recovery factor
ROI:	Return on Investment
T:	Time period
t:	Tonne
TC:	Total Costs
UK:	United Kingdom
UoS:	Use of System
ρ_c:	Density of coal
a:	Decline rate
n:	Years

1.0 Introduction

Meeting the challenges of reduced carbon dioxide emissions and the provision of competitive energy costs is more important than ever. Combine these two vital objectives with maintaining the security of energy supply is considered vital and of strategic importance for Europe. In UK, natural gas forms a key part of the energy supply and is important not only for electricity production, but also for domestic heating, cooking and industrial production (DECC 2014). In recent years, the UK has become increasingly dependent on gas imports, with annual UK gas consumption of approximately 85 billion cubic meters; while the Government forecasts that nearly 70% of the UK's gas supply will be imported by 2025. In 2012, the British Geological Survey (BGS) estimated that there are approximately 2,900 billion cubic meters of onshore coal bed methane (CBM) in UK (DECC, 2013a). Even with a yield of 10%, the potentially recoverable resources of CBM (at 290 billion cubic meters) could contribute significantly to safeguard the energy needs of the country for the next decades to come and until the transition to renewables. Today, there are a number of active CBM production sites in UK, including the one in Staffordshire and Airth in Scotland (DECC 2015b). Current success in the production of CBM in these areas shows that it could be implemented in other parts of the UK, including South Wales (Plaid Cymru Shadow Minister for Energy 2014).

Coal bed methane is gas of natural origin formed as part of the geological process of coal generation, and is contained in varying quantities within coal (Rogers et al., 2007). CBM can be recovered by drilling into the coal seams, initially releasing water to lower the pressure and then allowing the desorption of the methane gas from the internal surfaces of the coal, where it is able to flow either as free gas or dissolved in water towards the production well at the surface. By controlling the release of pressure in the coal seam, methane can be captured (Rogers et al., 2007; Wang et al. 2011; Moore 2012). Occasionally, CBM extraction may need to be enhanced by hydraulic fracturing when insufficient natural permeability of the coal exists (Clarkson 2011). Concentration levels of methane recovered via these techniques can often exceed 95%, making the gas suitable for use as a direct replacement for conventional natural gas in pipeline networks. This gas can then be compressed and supplied to market (e.g. heating, chemicals, gas to liquids etc) (Khalilpour 2012). The high quality of the gas recovered from unmined coal seams also renders it suitable for replacing or supplementing conventional natural gas in a combined cycle gas turbine system (CCGT). A schematic illustration of the CBM-CCGT process is shown in Figure 1. Successfully developing a coal bed methane field requires prudently managing the technical as well as the economic aspects of the project. The profitability of a coal bed methane (CBM) project is site specific and is highly dependent on various geological and market dependant factors (Hammond 2011).

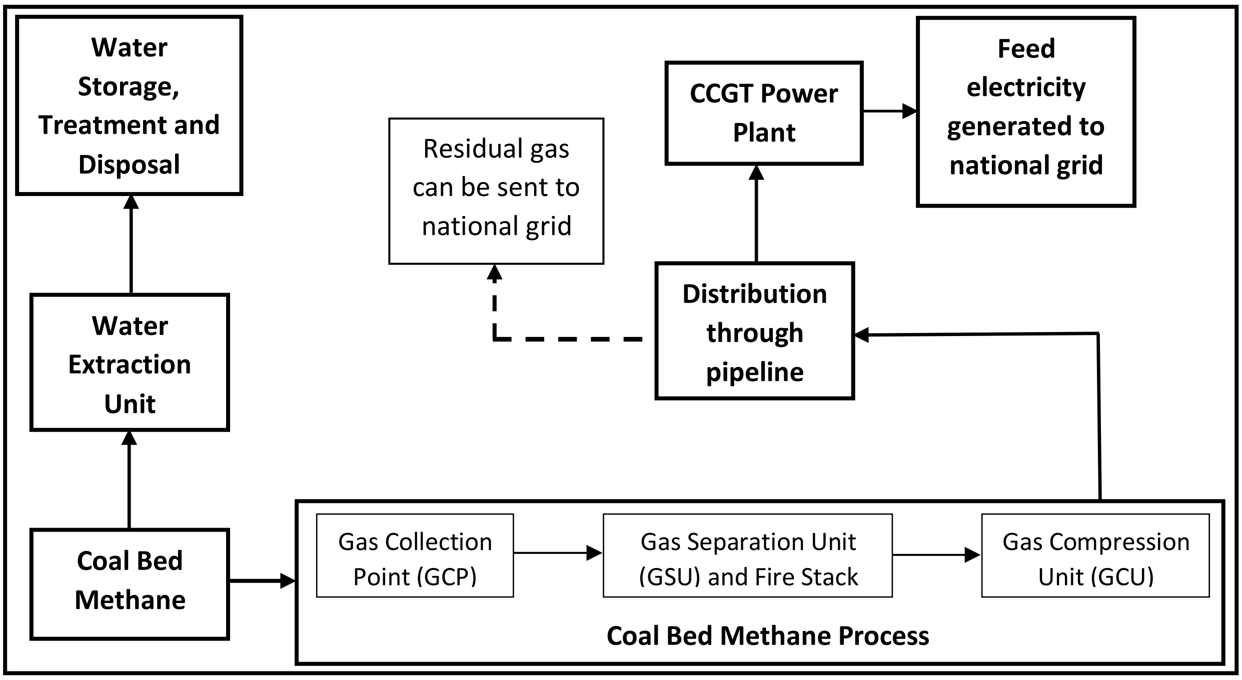


Figure 1. The coupled CBM-CCGT process.

2.0 Objectives and methodology

This study presents a transparent documentation of the development and application of a techno-economic model to investigate the economic viability of methane recovery from unmineable coal seams and the subsequent electricity generation in a CCGT power plant. The techno-economic model developed for CBM-CCGT cost of electricity (COE) determination is controlled by geological, technical and market dependant model input variables adapted to site specific boundary conditions for any selected target area worldwide. As a case study, data from a well exploited site in the South Wales, UK is considered. Part of the techno-economic model is to predict the future gas production and electricity generation from a target site, evaluate the capital expenditure (CAPEX) and the operational expenditure (OPEX) of the coupled CBM-CCGT process and determine the levelised costs of electricity (LCOE). Statistical analyses with the use of Monte Carlo analysis were employed and the degree of certainty defined based on the following three scenarios: a) proved estimates (P10); b) probable estimates (P50); and c) possible estimates (P90). Cash flows for the different scenarios were also determined and compared based on the revenues obtained from selling electricity generated from the CBM-CCGT process to the national grid. The basic process layout for the developed techno-economic model of the coupled CBM-CCGT process is shown in Figure 2. A detailed description of the model and an application case study is presented in the following chapters.

The innovation provided by the present study is the discussion of a coupling scheme allowing for integration connecting the various sub-processes to the surface processes up to the production of electricity. This procedure allows for flexible adaptation of variations in the model as well as allows the implementation of sensitivity studies which will be discussed in follow up publication.

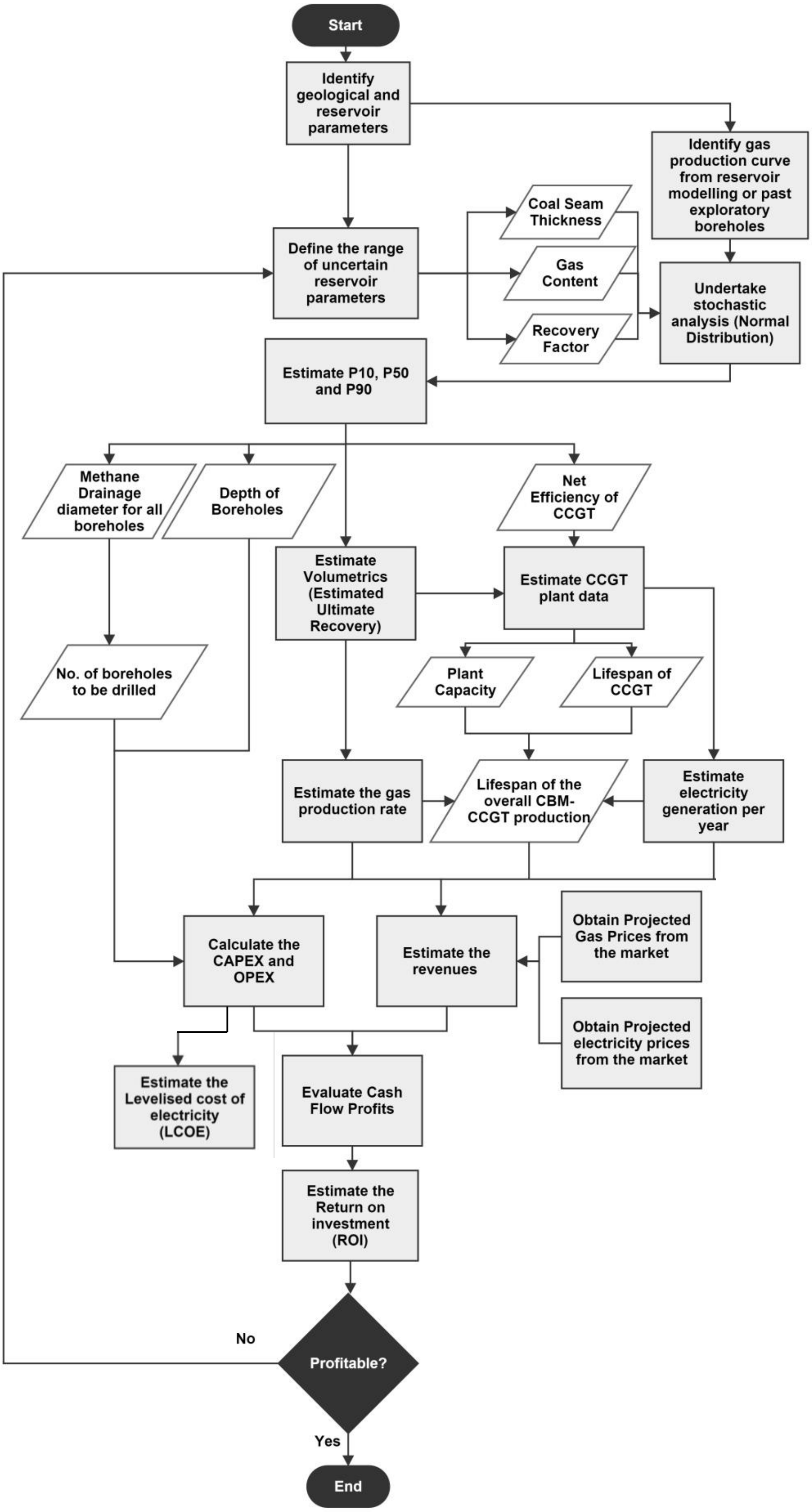


Figure 2. Flow chart for the techno-economic model development.

3.0 Factors influencing the CBM investment in South Wales, UK

3.1 Geology of the South Wales Coalfield

The South Wales Coalfield (Figure 2) is situated within an asymmetrical syncline approximately 96 km East-West and 30 km North-South and covers an area of about 2,690 km^2. It is an erosional remnant of a formerly extensive area of Carboniferous geology (Harris *et al*., 1996). The depth of the coalfield varies enormously across the entire area. In the east, the lowest coal seams do not reach depths greater than 60 m below Ordnance Datum (OD) while in the west (near Gorseinon) they are found at much greater depth exceeding 1,800 m below OD (Adams, 1967). The geology of South Wales distinctly displays a wide range of formations and rock exposures of varying ages and periods. The lithology of the area consists of Devonian formations, Carboniferous Limestones and Millstones formations and then the South Wales Coal Measures. The South Wales Coal Measures consist of: a) the Lower Coal Measure; b) the Middle Coal Measure; and c) the Upper Coal Measure. The Coal Measures are all of Carboniferous age and lie upon the Lower Carboniferous Limestones; which in turn lie upon the Devonian sandstone (Figure 3). The coal rank in the South Wales Coalfield varies from high volatile bituminous coals in the south and east crops to anthracite coals in the north-western part of the Coalfield (Bevins *et al*., 1996). The Lower Coal Measures can be observed to have more anthracitic coal seams compared to the Middle Coal Measures and the Upper Coal Measures. The Upper Coal Measures have more sub-bituminous ranked coal which are located at the southern part of the South Wales Coalfield (Bevins *et al*., 1996).

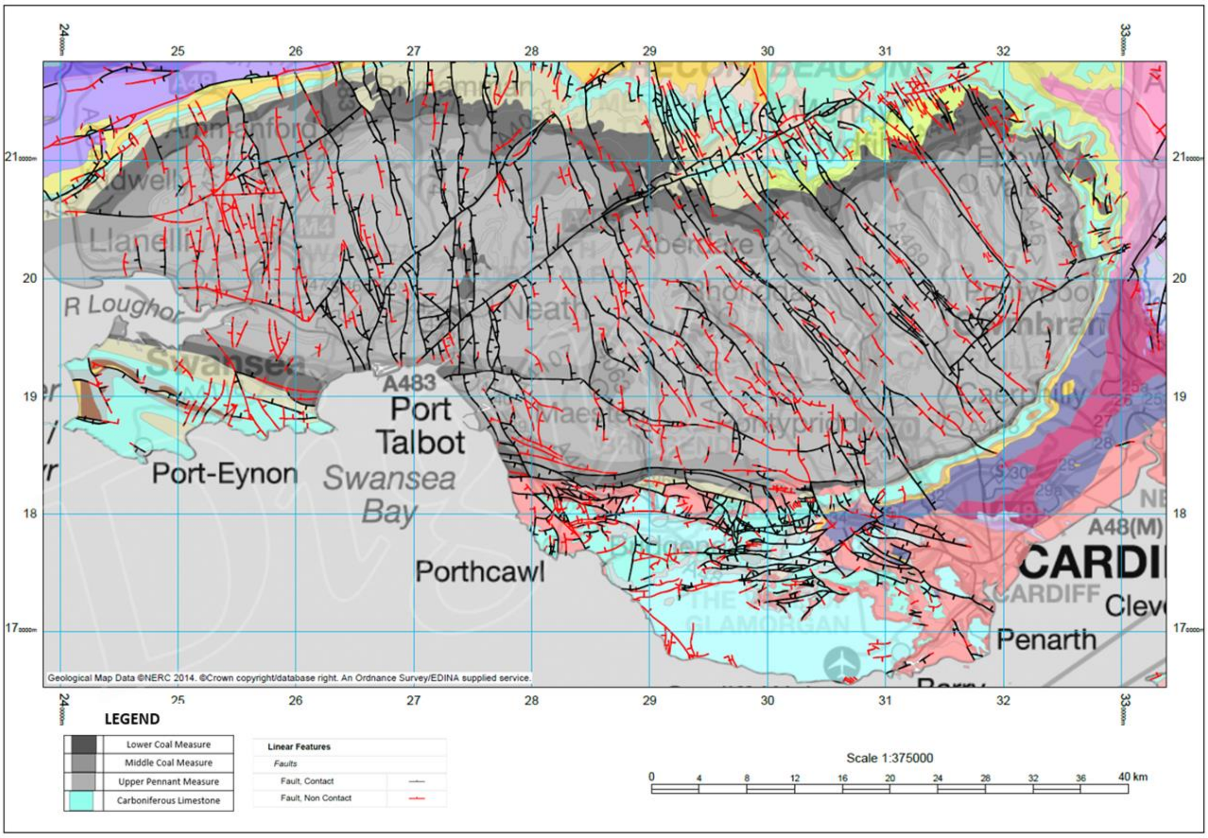


Figure 3. A simplified geology of the South Wales Coalfield showing the locations of the Coal Measure outcrops

3.2 Reservoir conditions, policies and commercial opportunities in South Wales

The gas recovery has a direct impact on the economics of a coal bed methane scheme. A sound resource base, ideally consisting of a few thick permeable coal seams with high content (>7m^3/t) is required for successful coal bed methane development. The South Wales Coalfield is characterised by gassy coal seams with relatively high methane content (Jones et al. 2004). Based on 173 samples from 24 boreholes taken at an average depth of 702 m, the mean methane content was found to be 13.3 m^3/t (Creedy, 1986). The average values derived from 18 anthracite coal samples taken from three boreholes were 18.3 m^3/t at an average depth of 692 m (Creedy, 1986).

Also, methane flow rates measured in seam boreholes in UK coal mines are generally 0.1 m^3 per day per meter of the borehole length. In North Wales at the Point of Ayr Colliery, borehole flows as high as 62 m^3 per day per meter length have been encountered in virgin conditions (Creedy 1999). However, there is little evidence that such flows can be produced in other parts in Wales. Coal permeability is another factor that influences the profitability of the coal bed methane operation and links directly to the amount of gas production. Coal permeability depends on the maturity, the cleat system and its degree of openness or mineralisation. Discontinuities in the coal, such as micro-fractures at the matrix and cleats of the coal contribute to the permeability and therefore the recovery of coal bed methane. Discontinuities provide pathways for bulk fluid and gas to flow at faster desorption rates (Freij-Ayoub, 2012). According to Hunt and Steele (1991) and Hughes & Logan (1990), a natural permeability greater than 1 mD is needed for the CBM operations to be economically attractive. The permeability of coal bed in the South Wales Coalfield ranges from 1 to 10 mD, which enforces the economic potential for recovering coal bed gas from this area (Shi and Durucan 2005). The permeability of coal seam can be further enhanced by hydraulic fracturing when and if necessary (Rogers et al., 2007) and in this case permeability can be up to 30 mD.

There are a number of existing project developers, operators, producers and equipment manufacturers able to support the development of CBM in South Wales (DTI 2001). These local expertise and equipment manufacturers will potentially influence future CBM productions in the area as local supply of equipment will be a lot cheaper than importing equipment from other countries. Furthermore, for Wales, a variety of legislation covers the individual activities related to unconventional gas developments (National Assembly Wales, 2012). Petroleum Exploration and Development Licenses (PEDLs) are also awarded in a series of '*rounds'* by the Department of Energy and Climate Change (DECC 2013a). Figure 4 shows the sites in South Wales where PEDLs were awarded to entitled companies during the 14th round on the 28th of July 2014.

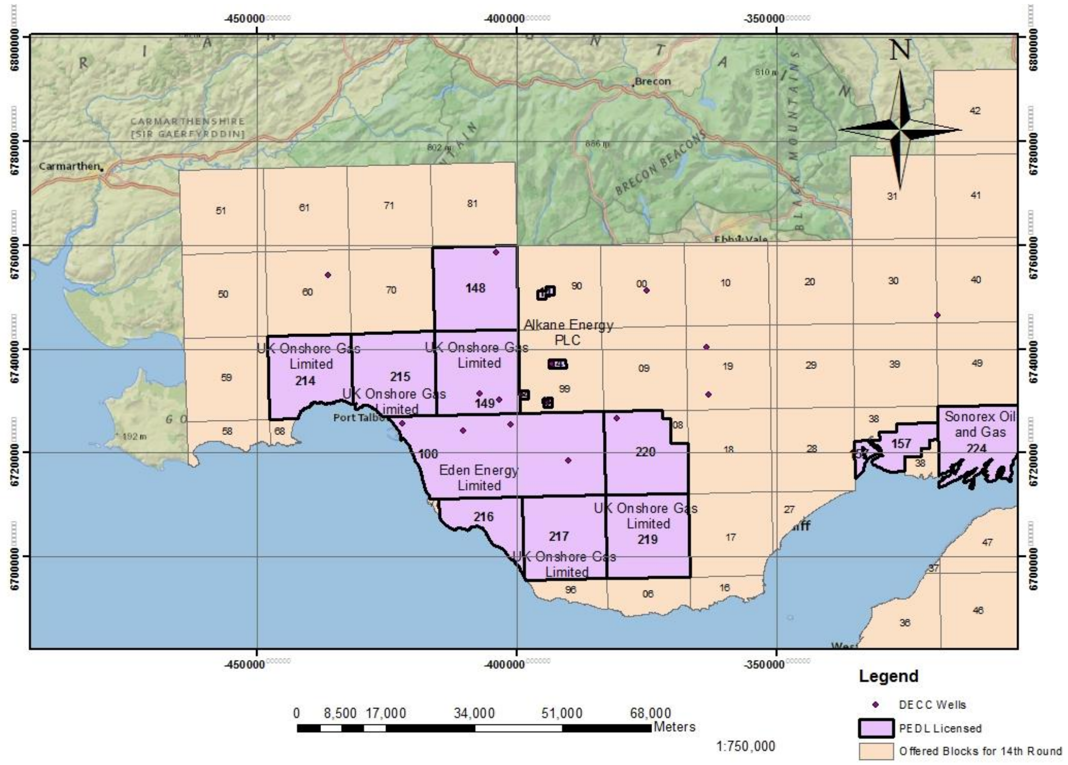


Figure 4. Areas that have been awarded PEDLs in South Wales during the 14th Round in 2014 (Map updated on 9th of March 2015) (Oil and Gas Authority 2013a).

4.0 Case study description and basic model assumptions

4.1 Study Area

The area under investigation is a coal deposit of Carboniferous age with anthracite coals located on the upper reaches of the Neath and Dulais Valleys in the county of Neath Port Talbot, South Wales. The coal seams are suitable for conventional mining but there may be an option to exploit their CBM potential before mining them. For examination, seven deep wells (at average depth 600 m), well log data for all wells, more than 20 cross sections of the area as well as historical data from Coal Authority were considered.

The ground is primarily forestry, under the ownership/lease of the Forestry Commission. The area is characterized by deep and dense faults (Figure 5). The largest discontinuity is a transcurrent fault that runs up the Neath Valley with a displacement in order of several kilometers.

The two major rivers Neath and Dulais are the principal controlling drainage elements in the area (Figure 5). There are also a few small rivers and streams that run across the hillside of the study area. The geological setting of the site is well defined due to historic borehole data. A cross-section of the study area is shown in Figure 6.

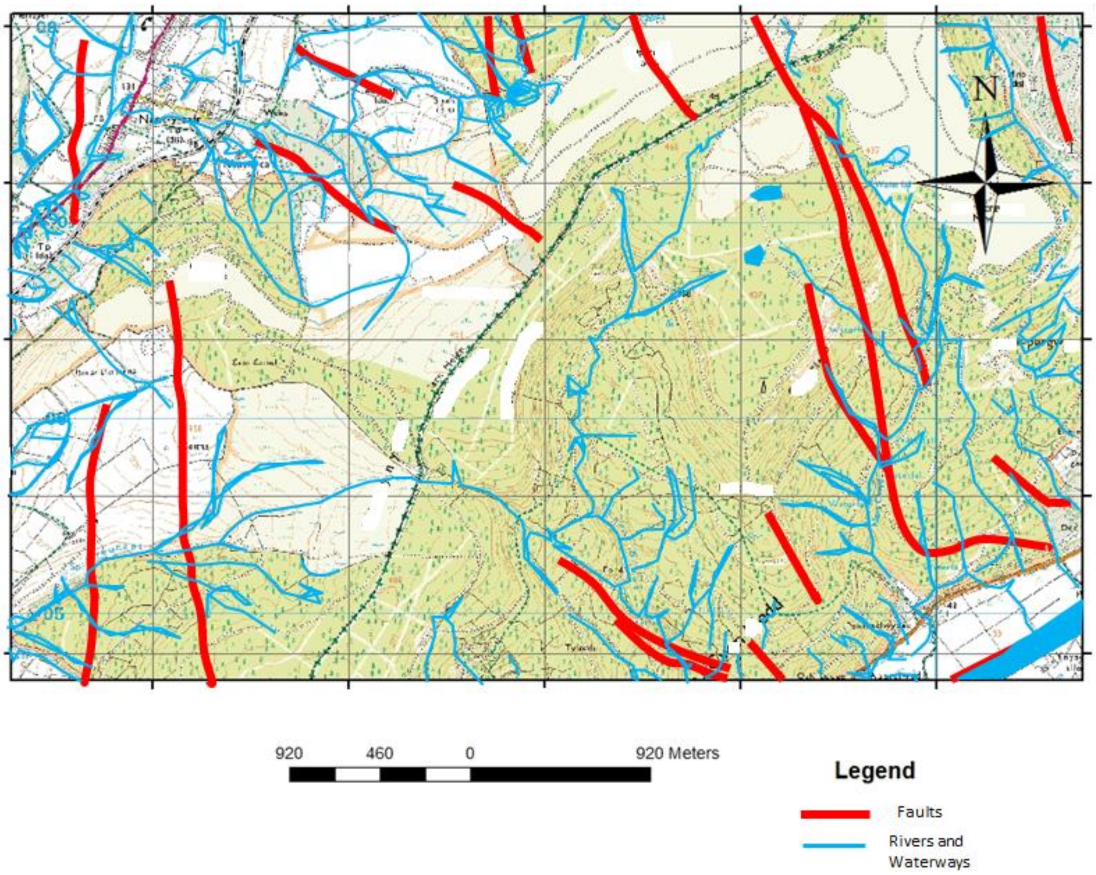


Figure 5. Waterways and geological faults of the study area.

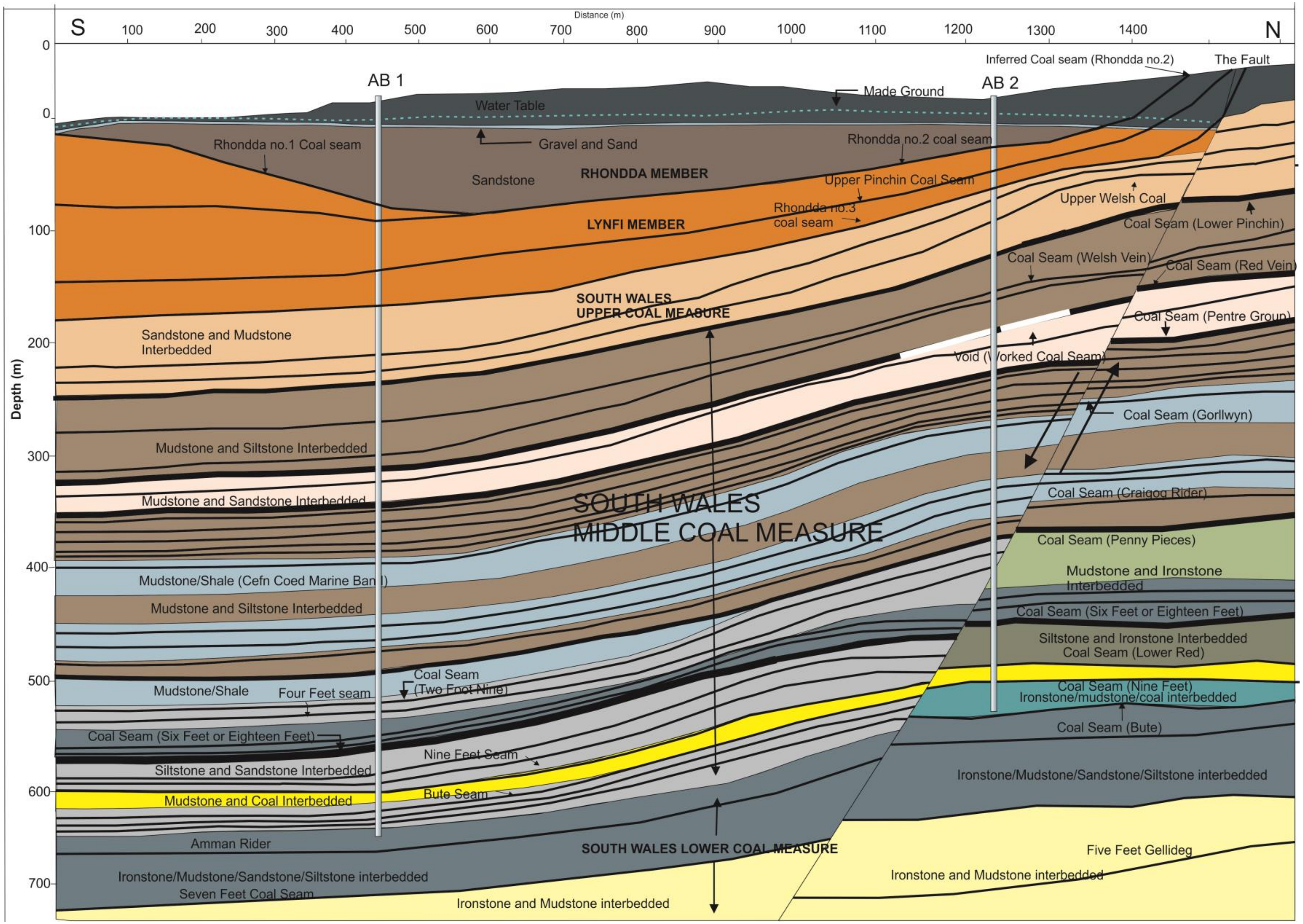


Figure 6. Cross section of the site.

4.2 Site selection criteria assumptions

The site selection criteria were developed based on successes and failures of previous experiments and pilot studies (Jones et al. 2004; DECC 2013a; van Berger 2003; Bevin et al., 1996). The criteria take into account the site characteristics, coal quality parameters, depths, the geology and hydrogeology of the area as well as environmental restrictions on the site. These criteria highlight the merits and demerits of the selected parameters, their importance in site selection and their economic and environmental potentials. Using the site selection criteria shown in Table 1, site buffers were drawn and the coal resource area identified and estimated (Figure 7). The coal resource area found to be equal to 4.14 km^2.

Table 1. Assumptions for the site selection criteria for CBM operations

Selection Criteria	Value	Reference
Resource area	Greater than 1 km^2	Jones et al., 2004
Gas content	Greater than 8.4 m^3/t	DECC, 2013a
Seam thickness	Greater than 1.5 m	DECC, 2013a
Depth of coal seams	Greater than 500 m and less than 1,000 m	van Berger, 2003
Coal rank	Greater than Bituminous	Bevin *et al.*, 1996
Permeability of coal and bedrock	Greater than 1 mD	DECC, 2013a
Proximity to populated areas	1,000 m away	van Berger, 2003
Proximity to underground mine workings	100 m away	van Berger, 2003
Proximity to fault zones	500 m away for major fault; 200 m away for minor fault	van Berger, 2003
Proximity to waterways	25 m away	van Berger, 2003
Proximity to aquifers	1,000 m away	van Berger, 2003

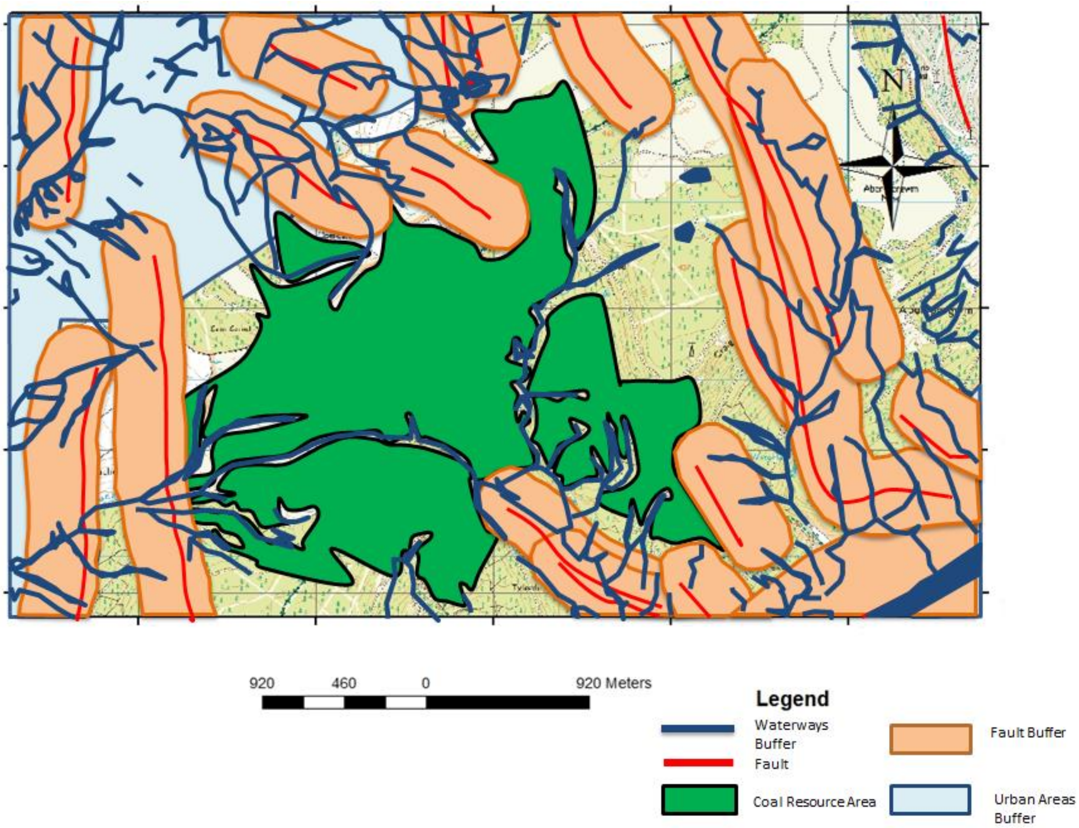


Figure 7. Site buffers and the coal resource area.

4.3 Coal seams considered and assumed range of their properties

Geological surveys show that the overall research area provides three coal seams suitable for coal bed methane which were investigated in the scope of the present study to ensure fuel supply for the CCGT plant for up to 41 years. The target coal seams are: a) the Eighteen Feet; b) the Nine Feet; and c) the Bute. The depth of the targeted coal seams ranges from 562 m to 623 m (ref. Figure 6). Desorption tests on twelve coal samples taken from the boreholes have been undertaken at the laboratory. From the results analysis it was found that the desorbed coal gas content ranges from 10.1 to 16.5 m^3/t.

4.4 Assumptions for the estimation of the gas in place

Based on the geological and reservoir conditions, volumetric analysis undertaken to calculate the volume of the methane in the coal beds (McGlade 2013). The original gas in place (OGIP) that is trapped in the coal seams calculated from Eq. 1 (Rogers *et al*. 2007):

$$\mathrm{OGIP} = \mathrm{A} \times \mathrm{h} \times \rho_c \times \mathrm{G_c} \tag{1}$$

, where A is the area (m^2); h is the cumulative height of coal in the area (m); ρ_c is the density of the coal (t/m^3); and G_c is the gas content of the coal (m^3/t). Also, the amount of recoverable gas calculated using Eq. 2 (Rogers *et al*., 2007):

$$\mathrm{EUR} = \mathrm{OGIP} \ \times \ \mathrm{RF} \tag{2}$$

, where EUR is the enhanced ultimate recovery (m^3), RF is the recovery factor and is equal to the ratio of the gas produced to the initial gas content (%). Due to the uncertainties in the reservoir parameters (e.g. coal seam thickness, recovery factor, gas content, depth of coal seams and methane drainage diameters), a probabilistic approach based on the Monte Carlo analysis (van Bergen *et al*., 2003) used for the estimation of the EUR. The amount of gas to be produced ranked according to the degree of certainty as follows:

a) **"*Proved*"** there is a 90% probability of meeting or exceeding the estimated proved volume (P10);
b) **"*Probable*"** there is a 50% probability of meeting or exceeding the estimated probable volume (P50); and
c) **"*Possible*"** there is a 10% probability of meeting or exceeding the estimated possible volume (P90).

4.5 Composition of coal bed methane and gas production rates assumptions

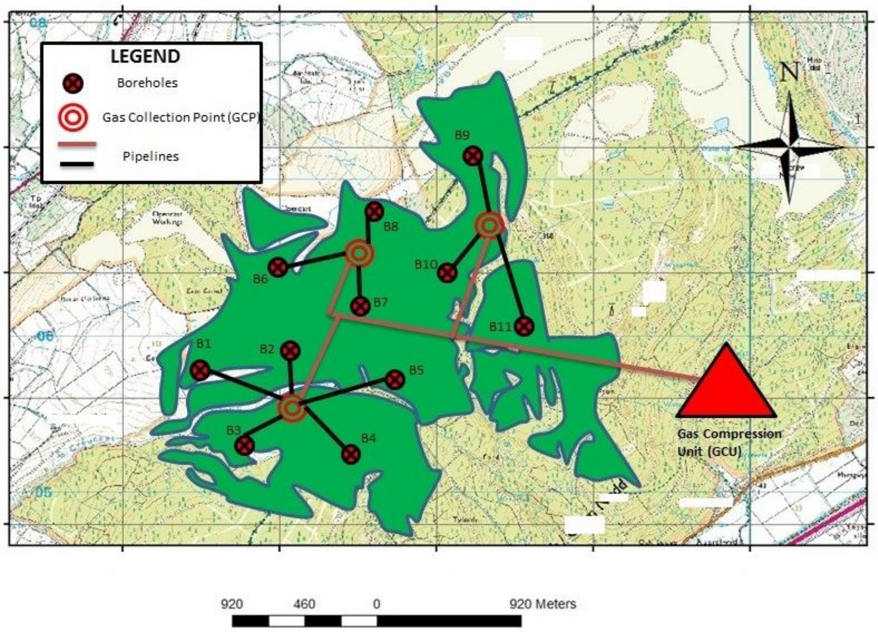
Samples of coal bed methane gas were obtained directly from the vertical boreholes during and after drilling. The samples were analysed by gas chromatography for the presence of hydrocarbons (Airey 1969). Methane in the gas varied from 95 to 99 percent; carbon dioxide from 0.1 to 2 percent. The majority of samples contained ethane, propane, and butane at concentrations below 2%. Very small concentrations of hydrogen and helium were found in some samples. Also, oxygen and nitrogen were present in very small concentrations, possibly as a result of air contamination. In the present study, it was assumed that the coal bed methane gas contains 97 percent of pure methane that can be compressed and fed via pipeline directly to fuel a CCGT.

4.6 Infrastructure and planning assumptions

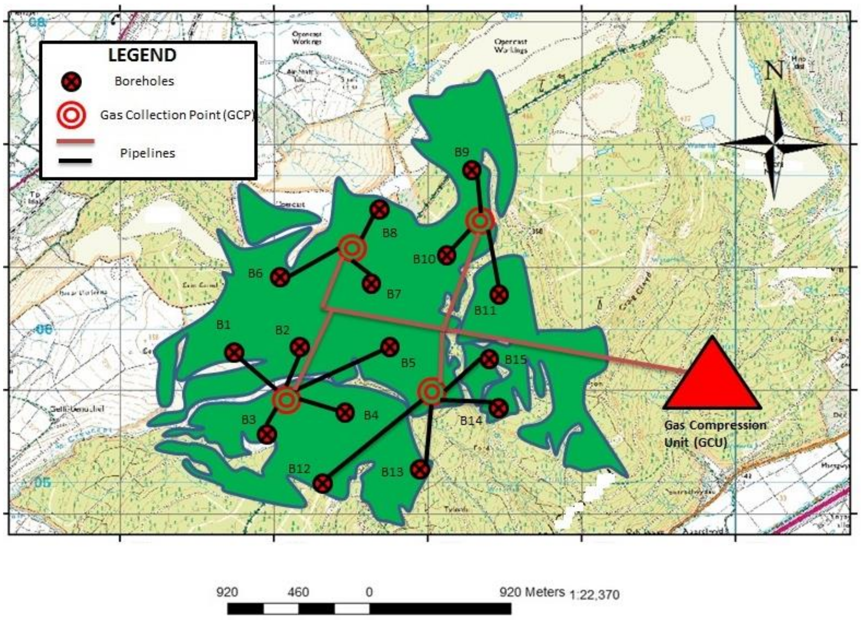
Drilling of boreholes, installation of pipelines, gas collection points, storage tanks, and construction of roadways for access on site are some of the most important infrastructure facilities required for coal bed methane development. Borehole production may last for many years and often drilling is carried out sequentially throughout the life of the project. The cumulative gas production and the reservoir conditions of the site have been used to calculate the extent of the volumetric drainage. For the three scenarios considered in this study, a circular drainage pattern has been assumed. The radius of the draining area ranged from 480 m to 650 m (Hosking et al. 2015; Clarkson 2013) with the majority of drilling to be undertaken in the first year.

Moreover, it was assumed that for every five boreholes at least one gas collection point (GCP) is required. Figure 8 shows the locations of the boreholes for the three scenarios under investigation (i.e. P10, P50 and P90). The larger the methane drainage area, the lesser the number of boreholes to be drilled on site.

Also, the water in the coal beds contributes to pressure in the reservoir that keeps methane gas adsorbed to the surface of the coal. This water must be removed during the gas extraction process by pumping in order to lower the pressure in the reservoir and stimulate desorption of methane from coal. As the amount of wells increases, the amount of water to be extracted will also increase. In the present study and since there were not past coal bed methane activities in the South Wales Coalfield, data from the Black warrior Basin in Alabama obtained. Based on 2,917 wells, the average water production was 58 barrels per day per well (assuming that 1 barrel contains 4.5 litters) (Rice and Nuccio 2000). The specification of such water abstraction have been used in the present study for the estimation of the size and number of pumps as well as for the waste water treatment facilities and fees for the water discharge.



(a)



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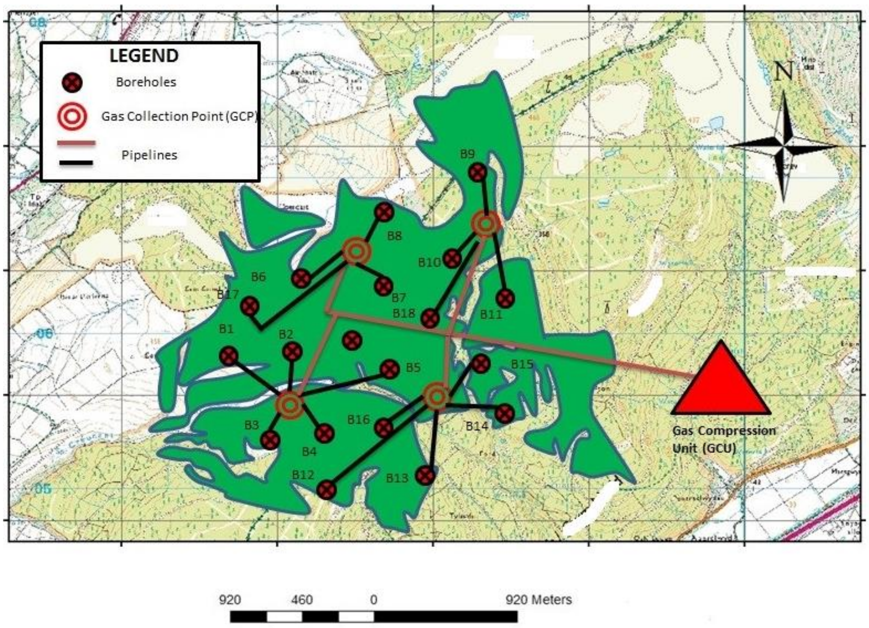

(c)

Figure 8. Spatial location of the boreholes for: a) P90 - 11 boreholes; b) P50 - 15 boreholes; c) P10 - 18 boreholes.

4.7 Electricity generation from CCGT assumptions

The potential of recovering methane from the deep coal seams and feeding it into a 50 MW CCGT power plant has been examined. Technical data about the proposed CCGT power obtained from an existing 50 MW CCGT power plant located in Yorkshire and operating for the last 20 years. The technical characteristics of CCGT power plant are shown in Table 2. The expected electricity generation by the coupled CBM-CCGT process depends on the capacity of the power plant and the expected efficiency. The capacity and lifespan of the CCGT plant depends on the size of the CBM reserve. The electricity generation (EG) per year in MWh can be calculated by:

$$\mathrm{EG} = \mathrm{PC} \times \mathrm{d} \times \mathrm{hr} \times \mathrm{E}\,(\%)\,, \tag{3}$$

where EG is the electricity generation in (MWh), PC is the power capacity in (MW), d are the days of operation of the power plant(e.g. 365 for a year), hr the hours of operation of the power plant (e.g. 24 hours per day) and E is the percent of efficiency of the power plant.

In the present study, it was assumed that the electricity generation could range from 2.83 to 2.65 MWh per year for the P10 and P90 scenarios accordingly.

Table 2. Key time periods and technical data for the CCGT power plant.

CCGT Plant Data		**P90**	**P50**	**P10**	**Units**
Key Time Periods	Total pre-development period	1	1	1	Years
	Construction period	1	1	1	years
	Plant Operating Period	20	15	10	years
Technical Data	Net power output	50	50	50	MW
	Net efficiency	65	63	61	%
	Average Load Factor	100	100	100	%
	Energy requirement for CCGT	2.03	1.48	0.954	10^{10} MJ
	Amount of Gas needed to be supplied over the lifespan	4.84	3.52	2.27	10^{8} m^3
	Electricity Generation per year	2.85	2.76	2.67	10^{5} MWh

5.0 Calculation results and discussion

5.1 Calculation of volumetrics

To consider the range of reservoir conditions and engineering factors influencing the volumetrics (Equations 1 & 2), statistical distributions were defined for each of the input parameters. The evaluation of the enhanced ultimate recovery was performed via Monte Carlo analysis (Gray 1987; McGlade 2013). Table 3 shows the minimum values, most likely values, maximum values, and standard deviations defining the distributions of the input parameters. A combination of literature survey and site specific data obtained as part of the current work have been used to gain an understanding of the gas content of the perspective site in the South Wales coalfield. The minimum and maximum values are those obtained from experimental tests on coal samples obtained during drilling exploration. The most likely methane content was set to 15.65 m^3/t (with a standard deviation of 0.455). Values of the recovery factor, RF, were taken from van Bergen et al. (2001). The value of the RF is related to the potential restrictions on the flow in the coal seam which in the South Wales coalfield are of particular low coal permeability (DECC, 2015a). This uncertainty can realistically be addressed through gaining more field experience in the region. Monte Carlo simulation for the effective gas storage capacity was performed and produced the results shown in Figure 10 and Table 4. Figure 9 shows the cumulative probability plot of the Monte Carlo simulation results for the effective methane storage capacity of the perspective site while the P10, P50 and P90 percentiles are indicated. From the calculations, the total proved effective storage capacity is 3.48 x 10^8 m^3 (P10 scenario), with a probable capacity of 3.73 x 10^8 m^3 (P50 scenario) and a possible capacity of 3.96 x 10^8 m^3 (P90 scenario). These results have been calculated using the methodology described in Section 2. Also, the net efficiency of CCGT power plant ranged from 60.5% to 64.5% for the P10 and P90 scenarios accordingly (Parsons Brinkerhoff, 2011).

Table 3. Summary of the input values used for Monte Carlo simulations of the key parameters used to evaluate the EUR and volumetrics.

Parameters	Range	Min	Mean	Max	Standard deviation	Normal Value	Units
Coal Seam Thickness (*h*)	6.5 to 7.0	6.50	6.75	7.0	0.141	6.60	m
Gas Content (G_c)	13.3 to 18.0	13.3	15.65	18.0	0.455	15.45	m^3/t
Recovery Factor (RF)	50 to 60	50.0	55.0	60.0	2.836	54.81	%

Table 4. Monte Carlo simulation results for the different parameters.

	P90	P50	P10	Units
Estimated Ultimate Recovery (EUR)	3.96	3.73	3.48	10^8 m^3
Average depth of boreholes	639	600	560	m
Methane drainage diameter of the CBM boreholes	620	550	480	m
Net efficiency of CCGT power plant	64.5	62.5	60.5	%

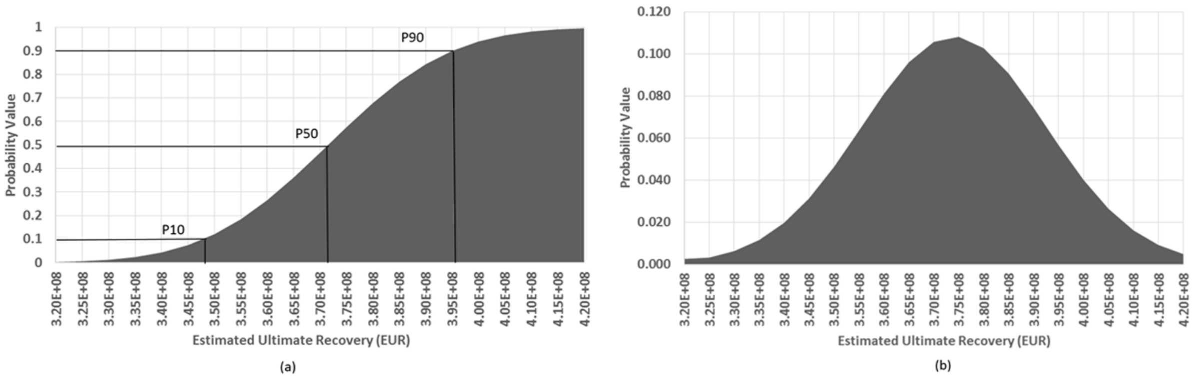

Figure 9. Monte Carlo simulation results for the estimated ultimate recovery (EUR) at the perspective site in South Wales Coalfield: a) Cumulative probability of the EUR showing the P10, P50 and P90; b) Histogram of the Monte Carlo simulation results

5.2 Decline curve analysis for the gas production and lifespan of the coupled CBM-CCGT process

For the estimation of future gas production, the decline curve analysis using the exponential decline technique used (Mazumder & Wolf 2004):

$$q_t = q_o e^{-aT}, \tag{8}$$

where q_t represents the production rate (m^3/day); q_o is the initial production (m^3/day); a is the decline rate (m^3/day); T is the time in days. The decline rate (a) and the time rate (T) calculated using equation 8. Also, the loss ratio (LR) and the cumulative gas produced (GP) evaluated using equations 9 and 10 below:

$$LR = \frac{q_o - q_T}{q_o} = 1 - e^{-aT} \tag{9}$$

$$GP = \frac{q_o - q_T}{a} \tag{10}$$

Results from the gas production decline curve analysis used to obtain the number of boreholes to be drilled each year. Also, the total amount of gas produced for each borehole over the lifespan of the project calculated by dividing the estimated ultimate recovery (EUR) to the number of boreholes drilled.

Since there are no past CBM activities in Wales and gas flow rates from coal seams are limited (Creedy 1999), for the purpose of this study, gas production rates obtained from the Black Warrior Basin in Alabama, USA. According to Jones et al. (2004) and Creedy (1994), Black Warrior Basin has similar characteristics to that of the South Wales Coalfield in UK. Using Eq. 8 to Eq. 10, isotherms presenting the logarithmic gas production rate (q_T) against time (t) have been created and the total amount of gas recovered per year estimated (Table 10). From Table 5, the probable amount of gas to be produced over the entire life of the CBM process found to be equal to 3.49 x 10^7 m^3/t. Also, the cumulative coal bed methane production and the lifespan estimated using the results from the gas production decline curve analysis (Figure 10). From the calculations, the lifespan for the coupled CBM-CCGT process found to range from 41 to 25 years for the P90 and P10 scenarios accordingly (Table 6).

Table 5. Recoverable coal bed methane for P10, P50 and P90 scenarios studied

Gas Production	P90	P50	P10	Units
Total gas produced per borehole over the lifespan	3.60	2.49	1.93	10^7 m^3/t
Gas produced per borehole for the first year only	2.02	1.80	1.70	10^6 m^3/t

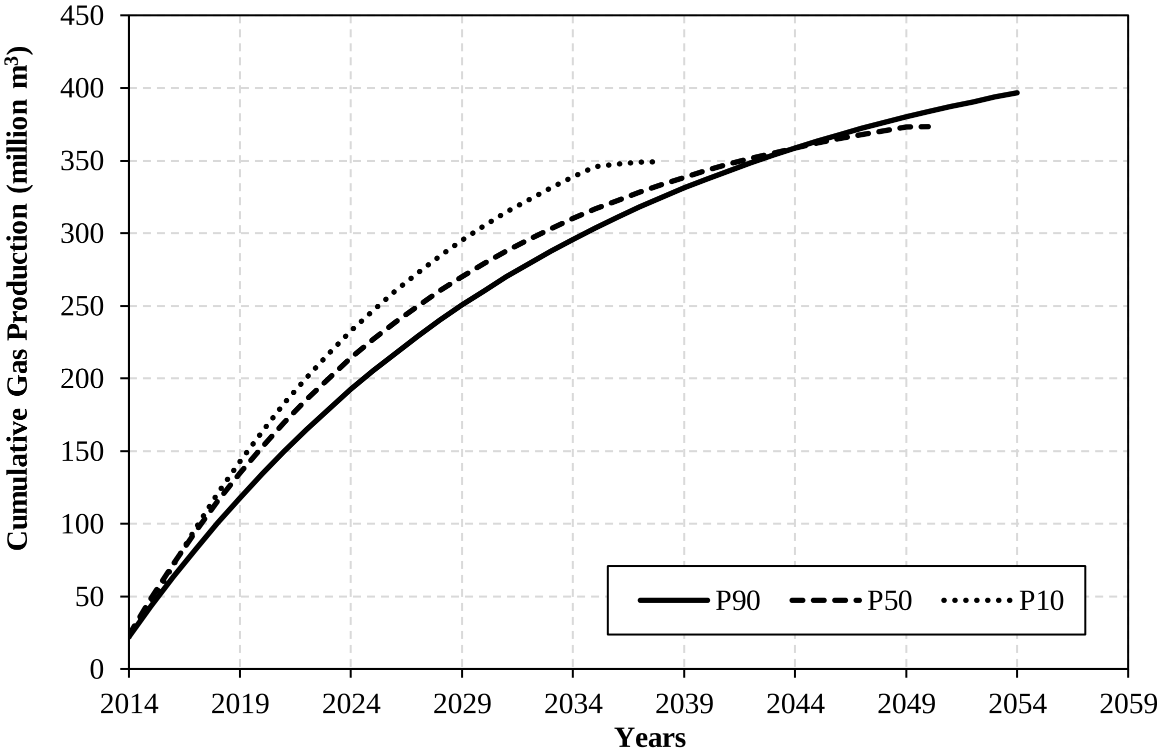

Figure 10. Cumulative gas production rate over the lifespan of the CBM-CCGT process.

Table 6. Lifespan for the coupled CBM-CCGT process

	P90	P50	P10	Units
The lifespan of the CBM-CCGT process	41	37	25	Years

Time for selling electricity	20	15	10	Years
Time for producing gas	41	37	25	Years
Time for selling gas only	21	22	15	Years

5.3 *Capital Expenditure (CAPEX)*

CAPEX includes the total funds needed to acquire infrastructure and equipment for the CBM-CCGT development. CAPEX estimated using the reservoir and geological property conditions of the site and cost of the infrastructure and equipment shown in Table 7 and 8.

Also, for each of the P10, P50 and P90 scenarios and from Figure 8, the length of the pipelines estimated. The cost for the construction of the pipelines is shown in Table 9. The cost of the fracking equipment and the number of water pumping units required for each scenario estimated based on the number of boreholes to be drilled and results are shown in Table 10. The CAPEX for CBM production is shown in Figure 11. Also, the CAPEX for the CCGT power plant includes licensing, engineering, procurement, construction works and is shown in Table 11.

Table 7. The costs of infrastructure and equipment (CAPEX) for CBM development

Infrastructure and Equipment (CAPEX)		**Costs**	**Units**	**Reference**
Equipment	Fracking Equipment	30,000	£/unit	Energybiz, 2014
	Water Pumping Unit	20,000	£/unit	Energybiz, 2014
Infrastructures	Road Construction	1000	£/m	Archer *et al*., 2006
	Gas Collection Points (GCPs)	87,000	£/unit	Zhou *et al*., 2013
	Gas compression unit (GCU)	1,000,000	£/unit	Zhou *et al*., 2013
	Methane Pipelines	116	£/m	Archer *et al*., 2006
	Gas Clean up Facility	50,000	£/unit	Zhou *et al*., 2013
	Gas Storage tanks	100,000	£/unit	Zhou *et al*., 2013
	Flare stack	50,000	£	Zhou *et al*., 2013
Others	Cost of decommissioning boreholes	50,000	£/unit	
	Safety, monitoring, licenses and verification costs	13,000	£	DECC, 2015b
	Environmental Impact Assessment	20,000	£	Oosterhuis, 2007
	Other infrastructures	100,000	£	

Table 8. The capital expenditure (CAPEX) for the CCGT development

CCGT Capital Costs (CAPEX)	**Costs**	**Units**	**Reference**
Pre-licensing, technical and design	12	£/kW	Parsons Brinkerhoff, 2011
Regulatory, licencing and public enquiry	0.4	£/kW	Parsons Brinkerhoff, 2011
Engineering, procurement and construction	640	£/kW	Parsons Brinkerhoff, 2011
Infrastructure	16.5	£/kW	Parsons Brinkerhoff, 2011

Table 9. Cost of constructing the pipeline network (to be read in conjunction with Table 1)

	P90	**P50**	**P10**
a) Distance of pipelines from the Gas Collection Point (GCP) to Boreholes (m)	5,437 m	7,822 m	8,871 m
Costs	£630,683	£907,298	£1,029,009
b) Distance of pipelines from GCP to Gas Storage Unit (GSU) (m)	4,388 m	4,817	5,008 m
Costs	£508,972	£558,763	£580,892

c) Distance from GSU to CCGT Power Station and National Grid (NG)	37,000 m	37,000 m	37,000 m
Costs	£4,292,000	£4,292,000	£4,292,000
Total Costs	**£5,431,655**	**£5,758,061**	**£5,901,901**

Table 10. Cost of water pumping unit and fracking equipment (to be read in conjunction with Table 1)

	P90	**P50**	**P10**
Water Pumping Unit	11	15	18
Costs	£220,000	£300,000	£360,000
Fracking Unit	11	15	18
Costs	£330,000	£450,000	£540,000

Table 11. CAPEX for the CCGT power plant only.

CAPEX for CCGT	**Costs**
Costs of pre-licensing, technical and design	£600,000
Costs of regulations, licencing and public enquiry	£20,000
Costs of engineering, procurement and construction	£32,000,000
Costs of infrastructure	£825,000

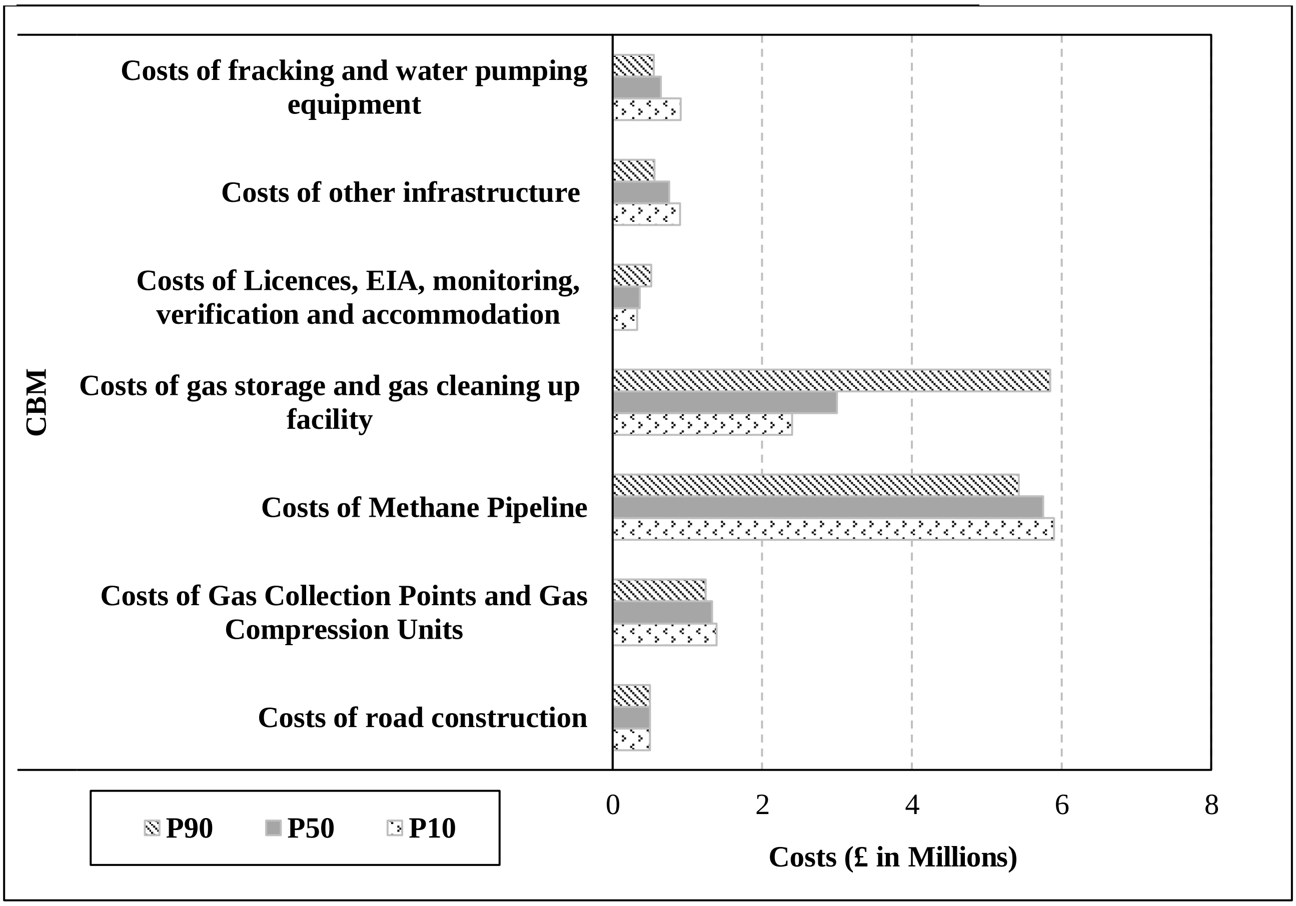

Figure 11. CAPEX for the CBM development.

5.4 *Operational Expenditure (OPEX)*

OPEX includes the total funds required for ongoing operations such as well drilling, hydraulic fracturing, water extraction from the boreholes and water treatment facilities, and the overall maintenance of the CBM-CCGT infrastructure facilities. Costs shown in Table 12 and Table 13 have been used for the estimation of the OPEX. Such costs are representative for the UK market.

Drilling cost is highly dependent on the depth of the target coal seams and the number of boreholes. In this study, the majority of the drilling work considered to be undertaken at the first year. The cost of hydraulic fracturing will also depend on the depth of the target coal seams, the reservoir properties (e.g. permeability) and the amount of fracking material (e.g. fracking fluid, propends etc) to be injected in the boreholes. The cost of pumping water out of the well will depend primarily on the local geological conditions. Based on the amount of water to be extracted, the size of the pumps determined. Based on historic data from past CBM exploration, it was assumed that the amount of water to be abstracted from each borehole per day could be on average 58 barrels per day (Rice and Nuccio 2000). For each of the scenarios studied, the total cost of drilling, fracking and extracting water is shown in Table 14. Also, the maintenance cost assumed to be equal to 10% of the actual costs for each equipment and infrastructure facility. Figure 12 shows the total OPEX for the CBM development over the entire lifespan of the project. From Figure 12, drilling of the boreholes and maintenance costs are by far the largest. Table 15 shows the OPEX for the CCGT process and includes the operating costs and maintenance costs.

Table 12. The cost of operations per unit (OPEX).

Operations and Costs	Costs	Units	Reference
Drilling boreholes	556	£/m	-
Fracking per meter depth along the borehole	58	£/m	Energybiz, 2014
Fracking fluid	5.50	£/ m^3	Energybiz, 2014
Proppant	40	£/ m^3	Energybiz, 2014
Water pumping	0.03	£/ m^3	SouthWestWater, 2015
Labour	300,000	£/year	-
Electricity for general purposes	10,000	£/year	DECC, 2015b
Fuel for water pumps	10,000	£/year	DECC, 2015b
Water disposal (no treatment)	50,000	£/year	SouthWest Water, 2015
Remediation costs (one off)	100,000	£	DECC, 2013a

Table 13. The costs of operations for a CCGT.

CCGT Operating Costs (OPEX)	Costs	Units	References
Operating and Maintenance fixed fees	23,182	£/MW/year	Parsons Brinkerhoff, 2011
Operating and Maintenance Variable fees	0.100	£/MWh	Parsons Brinkerhoff, 2011
Insurance	2,727	£/MW/year	Parsons Brinkerhoff, 2011
Connection and UoS (Use of System) charges	1,484	£/MW/year	Parsons Brinkerhoff, 2011
Carbon Costs	1.0	£/MWh	Parsons Brinkerhoff, 2011

Table 14. The costs of drilling, fracking and extracting water for each CBM reserves.

OPEX costs for CBM	P90	P50	P10
Costs of drilling boreholes (£m)	3.88	4.29	4.10
Costs of Fracking (£m)	0.54	0.66	0.64
Costs of water Extractions (£m)	1.35	1.67	1.35

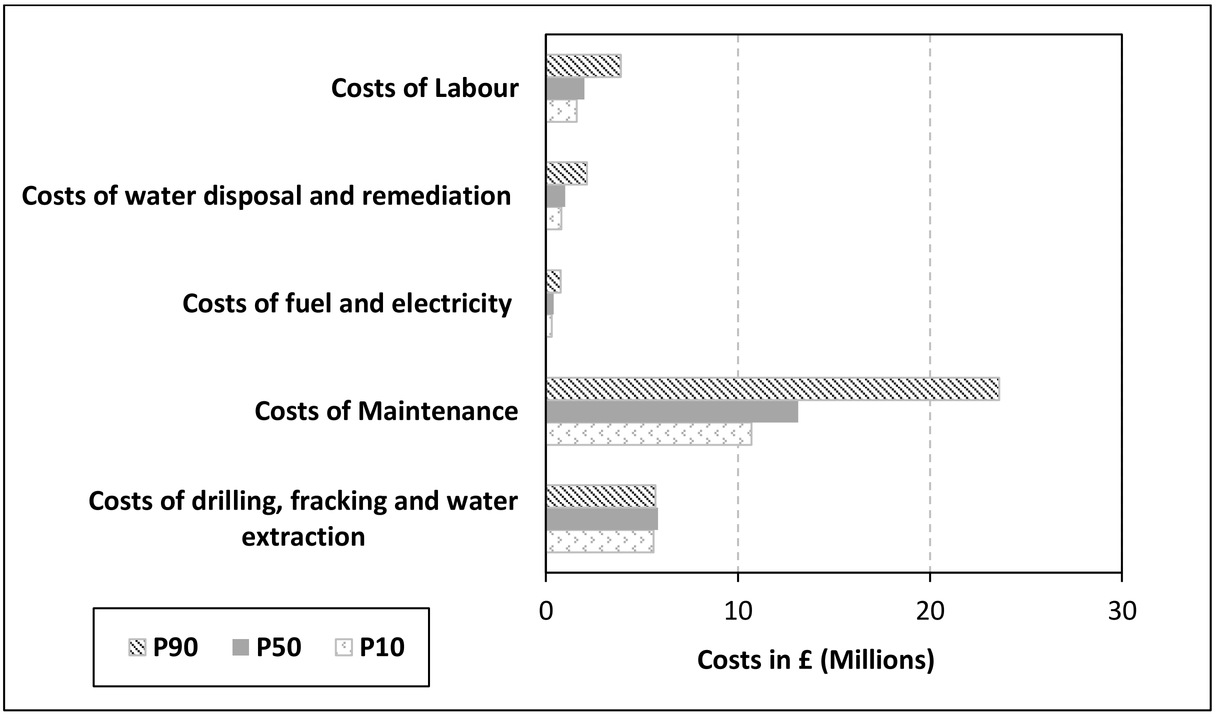

Figure 12. The OPEX for CBM development.

Table 15. The OPEX for CCGT power plant only.

OPEX for CCGT	P90	P50	P10
Costs of Operating and Maintenance (Fixed) (£m)	23.2	17.4	11.59
Costs of Operating and Maintenance (Variable) (£m)	0.57	0.41	0.26
Costs of Insurance (£m)	2.73	2.05	1.36
Costs of Connection and UoS (Use of System) (£m)	1.48	1.11	0.74
Carbon Costs (CC) (according to DECC) (£m)	48	31	16

5.5 Cost of investment (CoI)

Cost of investment includes the funds required for the planning period as well as for the OPEX for the first year of the project. Eq. 3 shows the cost of investment (CoI) for a CBM-CCGT includes both the total CAPEX and OPEX.

$$\mathrm{CoI} = \mathrm{CAPEX_n} + \mathrm{OPEX_n}\,, \tag{3}$$

where n is equal to the time period in years.

The costs of investment is shown in Table 16 and has been calculated by adding the CAPEX and OPEX for the coupled CBM and CCGT process. The discount rate estimates for coal bed methane operations are subject to a significant degree of uncertainty in UK. The approach for estimating the future evolution of discount rates relies on high-level policy scenarios and this is not part of this study. The discount rate considered in this study is equal to 5%. Although a 5% discount rate might be adequate for government, it would not possibly be adequate for any company. However, uncertainties and assumptions made in the model can be asses in the context of a sensitivity study and quantify the potential risk; such studied are not part of this paper. The NPV total costs estimated using the cost of investment and investment per year.

Table 16. The cost of investment and the investment per year

	P90	P50	P10
Cost of investment (£m)	46	47	46
Investment per year for CBM-CCGT (£m)	4.75	4.55	4.21
Investment per year for CBM only (£m)	0.95	0.999	1.01

5.6 Net present value and Levelised Costs of Electricity (LCOE)

The net present value (NPV) of electricity generation (EG) calculated by (DECC 2013b):

$$NPV_{EG} = \sum_{n} \frac{\mathrm{NEG_n}}{(1 + \mathrm{DR})^{n}} \tag{5}$$

, where NEG is the net electricity generation, n is equal to the time period and the discount rate (DR) is the interest rate in percentages. The expected outputs are expressed in net present value terms, resulted in discounted future costs, when comparing to the output today. The expected costs are also expressed in net present value terms, resulted in discounted future costs, when compared to costs today. The sum of net present value (NPV) of the total expected costs (TC) of developing a CCGT for each year is:

$$\mathrm{NPV_{CBM-CCGT}} = \sum\nolimits_{n} \frac{(\mathrm{CAPEX} + \mathrm{OPEX})_{n}}{(1+\mathrm{DR})^{n}}, \tag{6}$$

where DR is the discount rate. According to the DECC (2013b), the levelised cost of electricity generation is the discounted lifetime cost of ownership and use of a generation asset, converted into an equivalent unit of cost of generation in £/MWh.

The levelised cost of the CCGT is the ratio of the total costs of a generic CCGT plant (including both CAPEX and OPEX), to the total amount of electricity expected to be generated over the plant's entire lifetime. Both are expressed in net present value terms. This means that future costs and outputs are discounted, when compared to costs and outputs today. The levelised cost of electricity (LCOE) expressed by:

$$\mathrm{LCOE} = \frac{NPV_{TC}}{NPV_{EG}}, \tag{7}$$

where NPV of TC is the net present value of the total costs and NPV of EG is the net present value (NPV) of electricity generation. The levelised costs relates only to those costs accruing to the owner (or operator) of the asset (DECC 2013b).

The levelised costs of electricity (LCOE) calculated by dividing the NPV total costs by the NPV electricity generation. The total NPVs and the LCOE for each CBM reserves are shown in Table 17. The LCOE for a typical CCGT power plant in the UK is in the range of 70 to 80 £/MWh (DECC 2013b). The LCOE in this study is lower and ranges from 34 to 42 £/MWh since only a 50 MW capacity CCGT power plant has been considered.

Table 17. The NPVs and LCOE for each CBM reserves.

	P90	P50	P10
NPV total costs (£m)	82.6	77.2	68.1

NPV electricity generation (10^6 MWh)	2.41	2.1	1.6
LCOE (£/MWh)	34.3	37.1	41.8

5.7 Revenues (R) and Cash Flows (CF)

The amount of gas to be fed to a CCGT power plant per year is fixed. Depending on the gas production flow rates, there may be that a significant amount of the yearly produced gas will be fed to the CCGT while the remaining gas will be sold to the national gas grid. Therefore, revenues may well arise from both: a) the electricity to be produced by the CBM-CCGT process; and b) the surplus gas which will be fed into the national gas grid (Figure 1). Effectively, the electricity produced will be sold to the national electricity grid according to the wholesale electricity price per year whereas the remaining gas produced will be sold to the national grid according to the market price of gas. Future gas prices can be derived from the projections available by Navigant (UK prices) and shown in Figure 13. In 2014, the gas price was £0.24 per m^3 (DECC 2013b). The increase in the future gas prices are due to the projected yearly inflations, the growth in economy and the growth in gross domestic product (GDP) (Navigant 2014). The wholesale electricity prices projected by DECC (2013b) can be used to calculate the revenues from selling the electricity generated from the coupled CBM-CCGT (Figure 14).

Cash flow analysis should also be carried out to determine the cumulative gains from the revenues made after deducting the yearly outgoing costs, tax and insurance (Rogers *et al*., 2007). The cumulative cash flow (CF) at a given time calculated using Eq. 11:

$$\mathrm{CF_n} = \sum_{\mathrm{n}} (\mathrm{R_n} - \mathrm{OC_n}) , \tag{11}$$

where R are the revenues (or the total amount of cash the business receives from customers as payment for use of gas), OC are the outgoing costs and *n* is the time period.

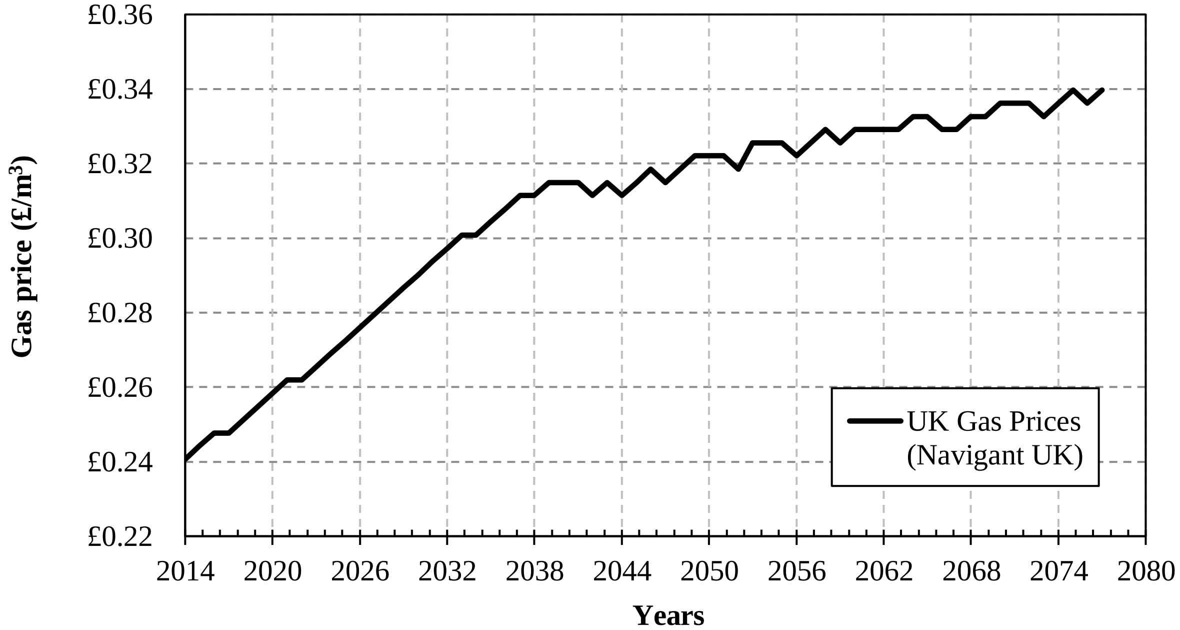

Figure 13. Projected UK Gas prices (Navigant, 2014).

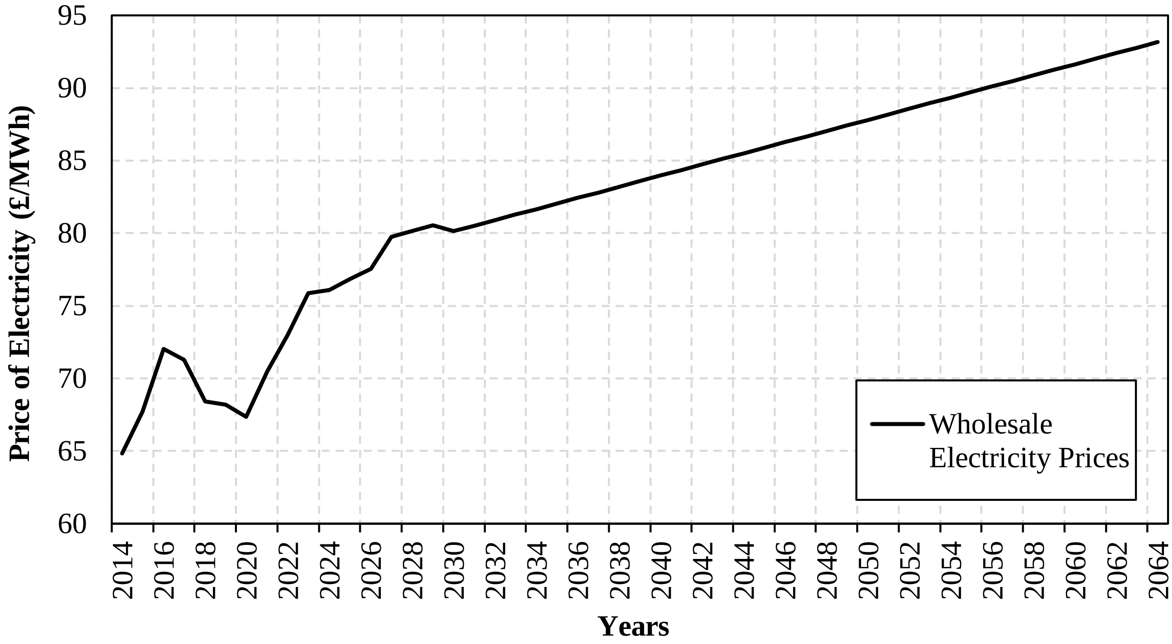

Figure 14. Projected wholesale electricity prices (DECC 2013b).

Revenues from selling electricity and coal bed methane to the national grid have been calculated and are summarised in Figure 15. Revenues from selling electricity to the national grid estimated using the DECC wholesale electricity prices (DECC 2013a). Also, the revenues from selling the excess coal bed methane have been determined using the Navigant UK gas prices (Navigant 2014). From Figure 16, for the different P10, P50 and P90 scenarios studied, revenues described by a declining trend which follows the production of coal bed methane and electricity generation trends obtained. Also, Figure 16 shows the overall NPV of the project starting from CAPEX in year zero and the cumulating the subsequent annual cash flows multiplied by the discount factor $(1/(1+DR))^t$. Also, the yearly investment, 20% VAT have been deducted from the revenues. From the results analysis it was found that for the P90 scenario, payout obtained after four years and the cumulative profits obtained over the project life are £100 million (Figure 12).

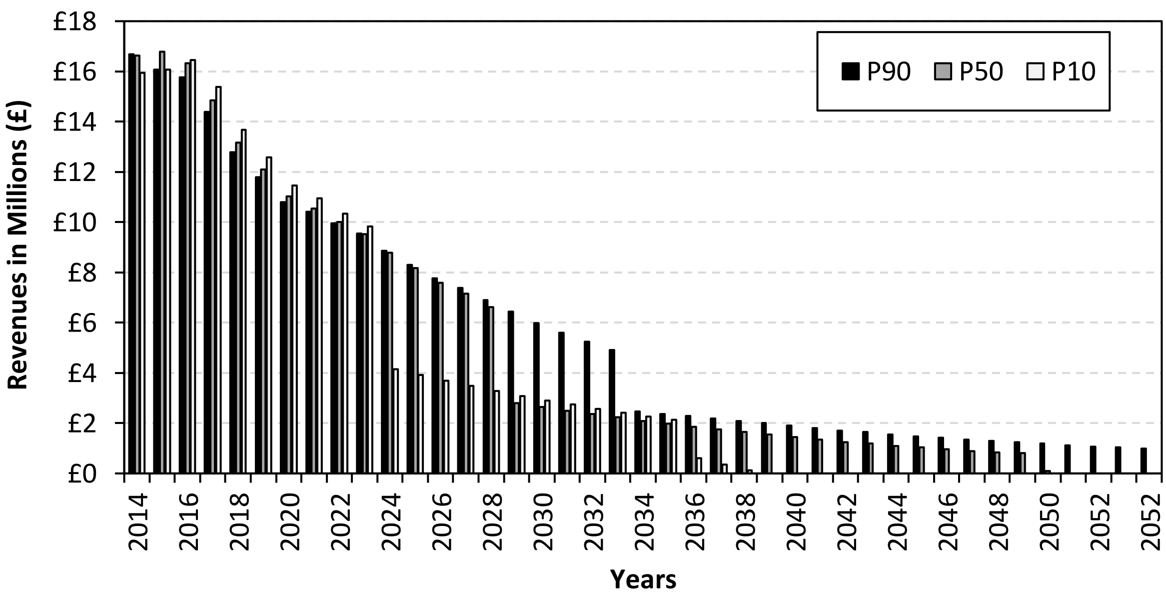

Figure 15. Revenues from selling electricity and coal bed methane to the national grid.

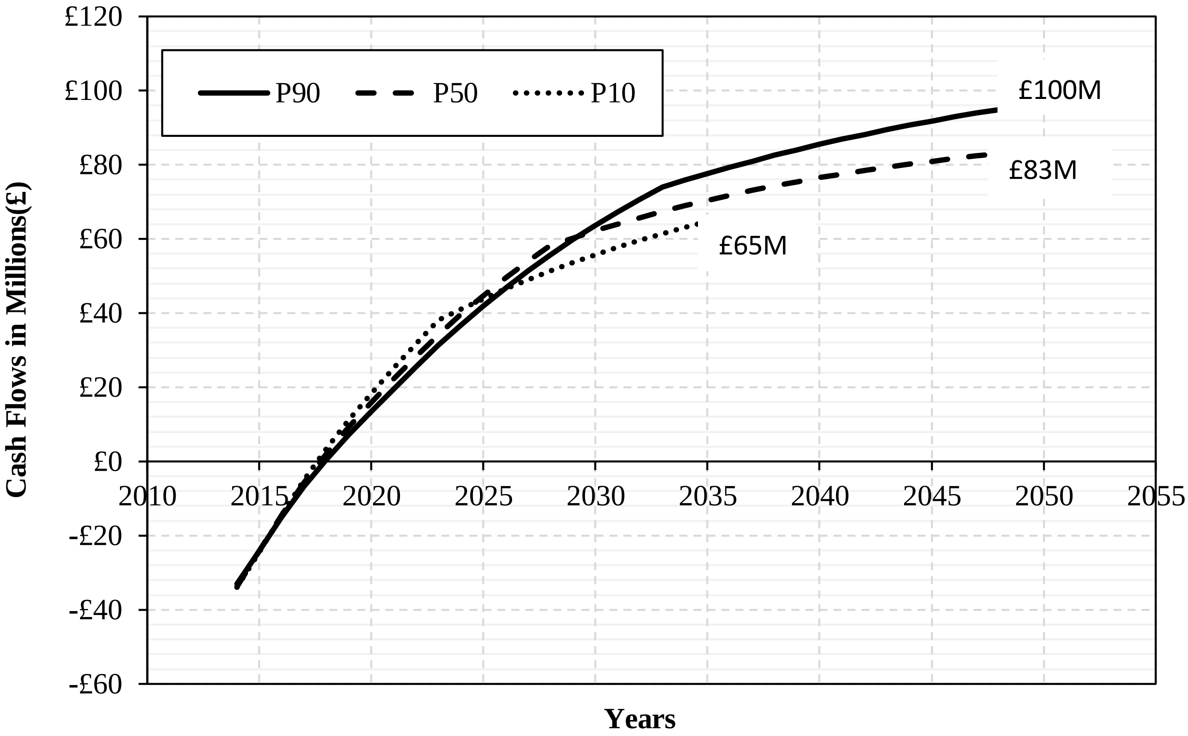

Figure 16. Overall NPV for the project for each CBM reserves studied.

5.8 Return on investment (ROI)

Return on investment (ROI) used to determine the amount of additional profits produced due to a certain investment. ROI is commonly used to compare different scenarios for investments and assess the one to produce the greatest profit and benefit. The ROI calculated using Eq.12:

$$\text{ROI}\ (\%) = \frac{\text{GfI} - \text{CoI}}{\text{CoI}}\ \text{x}\ 100, \tag{12}$$

where GfI is the gain from investment and CoF is the cost of investment. In Equation 12, "Gain from Investment” refers to the proceeds obtained from the sale of the investment of interest. Because ROI is measured as a percentage, it can be easily compared with returns from other investments, allowing one to measure a variety of types of investments against one another.

For each of the three scenarios studied, the return on investment calculated and comparisons made. First, the cost of investment needed to start the CBM-CCGT was estimated and then it was used to calculate the ROI according to the Eq. 12. The results are shown in Table 18. For the three scenarios studied, the ROI ranged from 40% to 116% while the probable ROI found to be equal to 78%.

Table 18. The return on investment (ROI) for each of the CBM reserves.

	P90	**P50**	**P10**
Return on Investment (ROI) (%)	116%	78%	40%

6.0 Conclusions

The development and application of a dynamic techno-economic model for calculating the return on investment for a coupled CBM-CCGT operation at a study area in the South Wales Coalfield is presented. A coal resource area was selected based on a series of site selection criteria. Statistical analysis on the reservoir parameters (i.e. thickness of the coal seams, recovery factor and gas content) have been undertaken. Using results from Monte Carlo simulations the enhanced ultimate recovery (EUR) estimated for the three scenarios: a) P10 - possible; b) P50 - probable; and c) P90 - proved values. Also, the revenues for utilising the recoverable coal bed methane to generate electricity by a CCGT power plant and selling the electricity generated to the national electricity grid has been calculated.

The economics of the CBM are highly site specific depending upon the reservoir quality and cost/price relationships found in each individual basin and specific project. In this study, every effort made to make this analysis on basis using common assumptions. The process design and parameter value choices underlying this analysis are mainly based on public domain literature. For these reasons, these results are not indicative of potential performance, but are meant to represent the most likely performance given the current state of public knowledge.

At the perspective site, for the P50 scenario, results from the overall techno-economic model show that the coupled CBM-CCGT development can yield a cash flow profit of £83 million in 37 Years. This results in return on investment of 77.6% based on an investment of £47 million for the first year. Also, the levelised costs of electricity (LCOE) calculated and found to range from 34.3 to 41.8 £/MWh accordingly. For the selected study area, the coupled CBM-CCGT process is considered as an economic option for power generation.

The methodology presented in this paper can be applied to any new or emerging coal bed methane development project to assist in quantification of the economics. In the future, a sensitivity study will be undertaken with the aim to provide and evaluate the overall economic viability of South Wales CBM resource and the factors with most impact on the economic viability of CBM resource.

Acknowledgements

The work described in this paper has been carried out as part of the SEREN project within the GRC (Geo-environmental Research Centre) at Cardiff University and funded by the Welsh European Funding Office (WEFO). The financial support is gratefully acknowledged.

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