ESTIMATION OF THE METHANE RESOURCES IN THE RICHMOND COAL BASIN, VIRGINIA

by

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Chapter I

INTRODUCTION

Methane is the byproduct of the conversion of plant material to coal and is a normal constituent of the atmosphere in coal mines. It is retained in the coal by absorption - penetration in the molecular structure of coal, and, adsorption - penetration on the internal surfaces of coal. The absorption of methane in coal is not considered significant as compared to adsorption.

Methane is retained by coal mainly in an adsorbed state on its surfaces. Because of its basic graphitic structure, coal contains an extensive network of fine pores, called micropores in diameters of the order of 5 to 10 Angstroms. Hence, coal has a large internal surface and methane is adsorbed on these surfaces under pressure.

Due to the release of pressure during mining, large volumes of methane are emitted into the mine atmosphere. The presence of methane in the mine atmosphere constitutes a serious fire and explosion hazard. This is due to the fact that between concentrations of 5 to 15%, methane can form an explosive mixture with air, with the maximum explosive force occuring at about 9% methane. While a gas explosion can be localized, its more serious effect is in initiating a coal dust explosion, which can be more widespread and disastrous to life and property as compared to a methane explosion.

Control of methane in underground coal mines is therefore very important. The following measures for control may be adopted, namely, dilution, removal, prevention and isolation.

Of these, dilution is the most widely and successfully used method of control. It involves providing enough fresh air to the workings so as to dilute the methane to concentrations below its explosive limit. This may be done by either main ventilation or local auxiliary ventilation or both. But as production increases and mines get deeper, larger quantities of methane are emitted requiring larger volumes of ventilation air, and beyond a limit, ventilation may not be adequate enough to cope with this methane.

Removal of methane ahead of the workings is another method and may be accomplished by drainage in advance of mining through bleeder entries or local exhaust ventilation. Drainage in advance of mining is a relatively new technique and is particularly applicable to multiple seams at great depths, gaseous seams and longwall mining (8). The principle of methane drainage is to remove the gas from a zone of reduced gas pressure created adjacent to mine workings. Bleeder entries are also used to control methane emission and the object is to collect methane close to the point of emission and remove it from the working places to prevent the buildup of high concentrations of methane in those areas.

Prevention involves having an adequate mining method and ventilation system so as to prevent high methane concentrations in the working areas.

Isolation may also be employed to control methane emissions. It involves the isolation and sealing off of the worked out areas which are usually zones of high gas emissions.

Over and above this, methane in itself constitutes a valuable energy resource. It has a high heating value and can be used to supplement natural gas as a source of energy. It could be marketed as pipeline gas or boiler fuel. In recent years, considerable work has been done on the recovery of methane for use as a fuel.

This thesis investigates the methane potential of the Richmond Coal Basin. The Richmond Coal Basin holds a large quantity of coal and possibly a large amount of methane and this work is aimed at estimating the methane potential of the basin so as to determine whether it may warrant additional exploration activity.

Chapter II

THE RICHMOND COAL BASIN

This chapter summarizes the existing knowledge of the geography, geology, stratigraphy, structure and coal measures of the Richmond Basin. Most of the information has been obtained from the literature, particularly a recent report prepared by Goodwin (7).

2.1 Location

The basin is located approximately 12 miles west of Richmond. It is somewhat elongated in shape with its long axis approximately north - south. It is 33 miles long, 9.5 miles at its maximum width and covers an area of about 170 square miles. Most of its area lies within Chesterfield county, but also includes portions of Amelia, Goochland, Henrico and Powhatan counties (Figure 1).

Access to the basin is through five major highways; Interstate 64, U.S. Highway 250, State Highway 6, U.S. Highway 60 and U.S. Highway 360 traverse the basin from east to west. The James River flows across its northern part. The Chesapeake and Ohio Railway and the Southern Railway also traverse the basin. It is connected to the city of Richmond by all these highways and railways.

Figure 1: Location map of the Richmond Coal Basin (22)

2.2 Geography

The Richmond Basin is part of the Triassic lowland subprovince within the Piedmont physiographic province. It is composed of Triassic sedimentary rocks cut by a few diabase dykes. The basin is characterised by a low gently rolling terrain and presents a mature topography. The steepest slopes occur near the major streams. The terrain is deeply weathered and the water table is near the surface. The total relief in the area is 303 feet. The James River is the main water course.

The dominant use of land within the Richmond Basin is for agriculture and timber, but along the northeastern outcrop, urban subdivisions are starting to be developed.

2.3 Geology and Stratigraphy

Igneous and metamorphic crystalline rocks completely surround and underlie the triassic sedimentary rocks of the basin.

Along the eastern margin, the Triassic rocks lie unconformably on a weathered surface of granite and gneiss. This unconformity is intersected by several cross faults mostly of small displacement. However, at least two cross faults cause major dislocations of the eastern margin of the basin.

The western margin has not been mapped in any great detail, but is believed to be dominantly a fault contact, and may consist of one or more normal faults steeply inclined to the east. The sedimentary rocks adjacent to the fault are highly folded and cut by numerous minor normal faults.

The western margin is also transected by three major cross faults which have a large separation and cause extensive offsets of the western border.

After deposition and deformation, the Triassic rocks were intruded by several diabase dykes. Many of these are only a few feet thick, but are 25 to 50 feet across. Coarse fluvial stream gravels were deposited on the Triassic rocks by the James and Appomatox Rivers. Most of these have been eroded away but appear as horizontal cappings on some of the higher surfaces south of the James River and near the Appomatox River.

The stratigraphy of the basin is very poorly known due to the incomplete records of old mine workings and drill hole data, the low topographic relief and lack of geophysical data. Shaler and Woodworth(19) defined a stratigraphic subdivision of the area and this division with some modifications is used today according to Goodwin(7). The stratigraphic section is shown in Table 1.

TABLE 1

Lithologic units in the Richmond Basin, modified slightly by Goodwin (7)

GROUPS	SUBDIVISIONS	GENERAL CHARACTERISTICS
Chesterfield Group	Otterdale sandstones	Coarse sandstones, often feldspathic. Thickness 500+ ft.
	Vinita beds	Black fissile shales, passing upward into and intercalating with gray sandstones. Thickness 2000 ft.
Tuckahoe Group	Productive coal measures	Interstratified beds of bituminous coal (3 seams), coke, shales, and feldspathic, micaceous sandstones. Thickness 500(?) ft.
	Lower barren beds	Sandstones & shales under coal beds, often with arkose. Thickness variable; 0 to 300 ft.
	Boskobel boulder beds	Local deposits; boulders of gneiss and granite. Thickness variable; 0 to 50 ft.

2.4 Coal Measures in the Basin

The Richmond Basin may be divided into five mining districts, namely, Deep Run Basin, Carbon Hill District, Midlothian District, Clover Hill District and Hugenot Springs District. The general location of these districts are shown in the map of Figure 1. The following gives brief information about these districts as described by Goodwin (7).

2.4.1 Deep Run Basin

This area lies outside the main basin in which the coal measures have been preserved. The coal dips steeply (upto 74 degrees east) on the western margin and gently (10 to 20 degrees west) on the eastern margin. The thickness of the coal in this basin has not been determined.

2.4.2 Carbon Hill District

This area lies to the northeastern part of the basin. Four coal seams are present in this area : The 'Coke' seam is uppermost in the section and is so named because the coal has been transformed to natural coke by diabase dyke and sill intrusions. This seam has an average thickness of 6 to 8 feet. There is about a 60 feet thick sandstone and shale parting between the 'Coke' seam and the underlying 'C' seam, which is between 2 to 5 feet thick. The 'B' seam lies below the 'C' seam with a 3 to 5 feet thick sandstone and shale parting between them. The 'A' seam underlies the 'B' seam separated by about 40 feet of sandstone and shale. The seams dip 25 degrees west on the average.

2.4.3 Midlothian District

This district is on the east side of the basin, beginning at the James River extending down to the Swift Creek Reservoir (Fig. 1). The Stonehenge, Union and Blackheath basins are included in this district. Four coal seams are present in this area. The uppermost averages 5 feet (3.5 ft. coal with 1.5 ft. shale partings) in thickness. The second seam is 1 foot thick and is located between the 47 feet shale and sandstone parting between the first and third seam. The third seam is 12 feet thick with 0.2 to 2 feet shale partings. The lowermost seam is 14 feet thick and is separated from the third seam by 10 feet of sandstone and shale. The dip averages 22 degrees west.

2.4.4 Clover Hill District

This district is situated at the southeastern side of the basin, extending south across the Appomatox River (Figure 1). Three coal seams are present in this area. The top seam (3 to 5 ft.) is separated from the main seam (7 to 20 ft.) by 10 to 30 feet of sandstone and shale. 40 to 50 feet of sandstone and shale separates the main seam from the bottom seam which is 4 to 6 ft. thick.

2.4.5 Hugenot Springs District

This district is located in the northwestern part of the basin, near Manakin. In one mine, two coal seams were reported: the uppermost (5 to 7 feet with shale bands) separated from the lower (6 feet with shale bands) by 10 to 12 feet of shale. In surrounding mines upto seven coal seams of unreported thickness have been encountered. Dips of the seams in this area vary from 20 degrees west to 30 degrees east.

2.5 History of Coal Mining in the Basin

Coal was first reported in the Richmond Coal Basin in 1701. The mining in this area can be divided into six phases.

The first phase of mining took place between 1701 and 1748. During this time coal was mined only in a desultory manner and only for domestic use.

The second phase is the period between 1748 and 1794. During this period the first commercial mining of coal in the basin took place. The basin was the major supplier of American coal to the colonies. However, production was small.

The third phase of mining covers the period between 1794 and 1843. Mining during this period was quite extensive and the total production was of the order of 2,892,645 tons according to Brown et. al. (3). Towards the latter part of this phase, the basin lost its importance as a major supplier of coal, due to the development of the Pennsylvania Anthracite regions.

The fourth phase of mining was from 1844 to 1864. Mining flourished during this period mainly due to the civil war. Coal mining previous to this phase was shallow, but, during this period, the mines were worked through deep shafts and inclines. Some of the drilling went downward 2000 feet and some of the mines were over 800 feet deep. The production was far greater than that before 1840, as is clearly seen in Table 2.

The fifth phase was between 1864 and 1880, when production started to drop because of difficult mining conditions. There were many methane explosions, the mines were undercapitalized and poorly managed. Due to this reason, they were unable to compete with mines of other regions and in the 1880's most of them were closed down.

The sixth and final phase of mining was between 1880 and 1923 and was centered around the Midlothian and Winterpock area. The mining was very intermittent and no large

TABLE 2

Coal Production in the Richmond Basin, 1748-1882,
(in short tons, from Brown et. al. (3))

Year	Tonnage	Year	Tonnage	Year	Tonnage	Year	Tonnage	Year	Tonnage	Year	Tonnage
1748	50	1771	500	1794	1000	1817	58000	1840	88000	1863	112068
1749	50	1772	400	1795	2000	1818	59000	1841	79000	1864	111742
1750	50	1773	400	1796	4000	1819	60000	1842	77000	1865	73730
1751	50	1774	400	1797	7000	1820	62000	1843	95606	1866	70912
1752	100	1775	400	1798	22000	1821	64000	1844	115313	1867	90810
1753	100	1776	400	1799	14000	1822	54000	1845	134603	1868	96184
1754	100	1777	500	1800	18000	1823	43966	1846	124669	1869	115564
1755	100	1778	500	1801	22000	1824	67040	1847	136422	1870	90200
1756	100	1779	500	1802	26000	1825	66720	1848	120747	1871	101932
1757	100	1780	500	1803	29500	1826	88641	1849	133801	1872	95973
1758	200	1781	500	1804	40500	1827	84720	1850	138017	1873	101504
1759	200	1782	500	1805	42000	1828	100080	1851	136523	1874	81651
1760	300	1783	400	1806	43000	1829	93350	1852	106687	1875	88706
1761	300	1784	400	1807	44000	1830	102799	1853	101726	1876	57182
1762	700	1785	400	1808	45000	1831	104320	1854	132554	1877	67907
1763	1400	1786	400	1809	46000	1832	132033	1855	125977	1878	50000
1764	800	1787	400	1810	47000	1833	159697	1856	106150	1879	45000
1765	900	1788	400	1811	48000	1834	124000	1857	114826	1880	43079
1766	600	1789	400	1812	50000	1835	201600	1858	113734	1881	50000
1767	500	1790	400	1813	52000	1836	124000	1859	106338	1882	112000
1768	500	1791	400	1814	4000	1837	112000	1860	112473		
1769	1000	1792	400	1815	56000	1838	107999	1861	94697	Total	7222167
1770	500	1793	700	1816	57000	1839	96000	1862	112000		

production was realized during this time. Work continued until the World War which gave a slight impetus to mining in the Midlothian vicinity. The production was about 50,000 tons in 1923.

After 1923, although there were sporadic attempts to revive interest and resume mining activity, it was largely unsuccessful. There was some activity around 1935 - 37, one in the Blackheath area, one in Winterpock and the third in the Hugenot Springs area, but, no production figures or length of mining activity have been reported.

Chapter III

METHANE ESTIMATION IN COAL SEAMS

An accurate value of the methane content of coal seams and adjacent strata is of prime importance in mine planning.

Results of earlier investigations by Borowski (2), Cybulski and Borowski (5) and Tarnowski (21) have shown that a close relationship exists between the gassiness of coal seams and the following geological factors :

1. Tectonics of the area
2. Depth of coal seams
3. Volatile matter content of the coal
4. Permeability of the adjacent strata
5. Physical characteristics of the coal, e.g. porosity, nature of compaction, etc.
6. Igneous intrusions

These relationships are required to be considered in order to devise a method of methane estimation and are discussed below.

1. Tectonics of the area : Geological disturbances cause an increase in the insitu or residual stresses and

fault planes act as conduits for the gas to migrate from one layer to another. The methane is concentrated mostly at the intersection of carboniferous and overlying strata and also near tectonic disturbances. When the seam has an anticlinal structure, more concentration of methane is likely to occur at the apex of the basin, but when it has a synclinal structure, the bottom of the basin is likely to have relatively less concentration of methane.

2. Depth of the coal seam : The occurance of methane is not necessarily confined to deep lying seams. But, as a general rule, a seam at a shallower depth is likely to be less gassy as compared to a seam at a greater depth. This is attributed to gas escaping to the surface through cracks and fissures.

3. Volatile matter content of the coal : Investigations indicate that a close relationship exists between the methane and volatile matter contents of coal, as has been shown by Stuffken (20). The methane concentration curve plotted against the volatile matter content is bell shaped in nature (Figure 2).

4. Permeability of adjacent strata : The overlying impermeable strata form layers known as reflectors for methane and these layers may prevent migration of gas occuring in the underlying coal beds. Layers of strata underlying

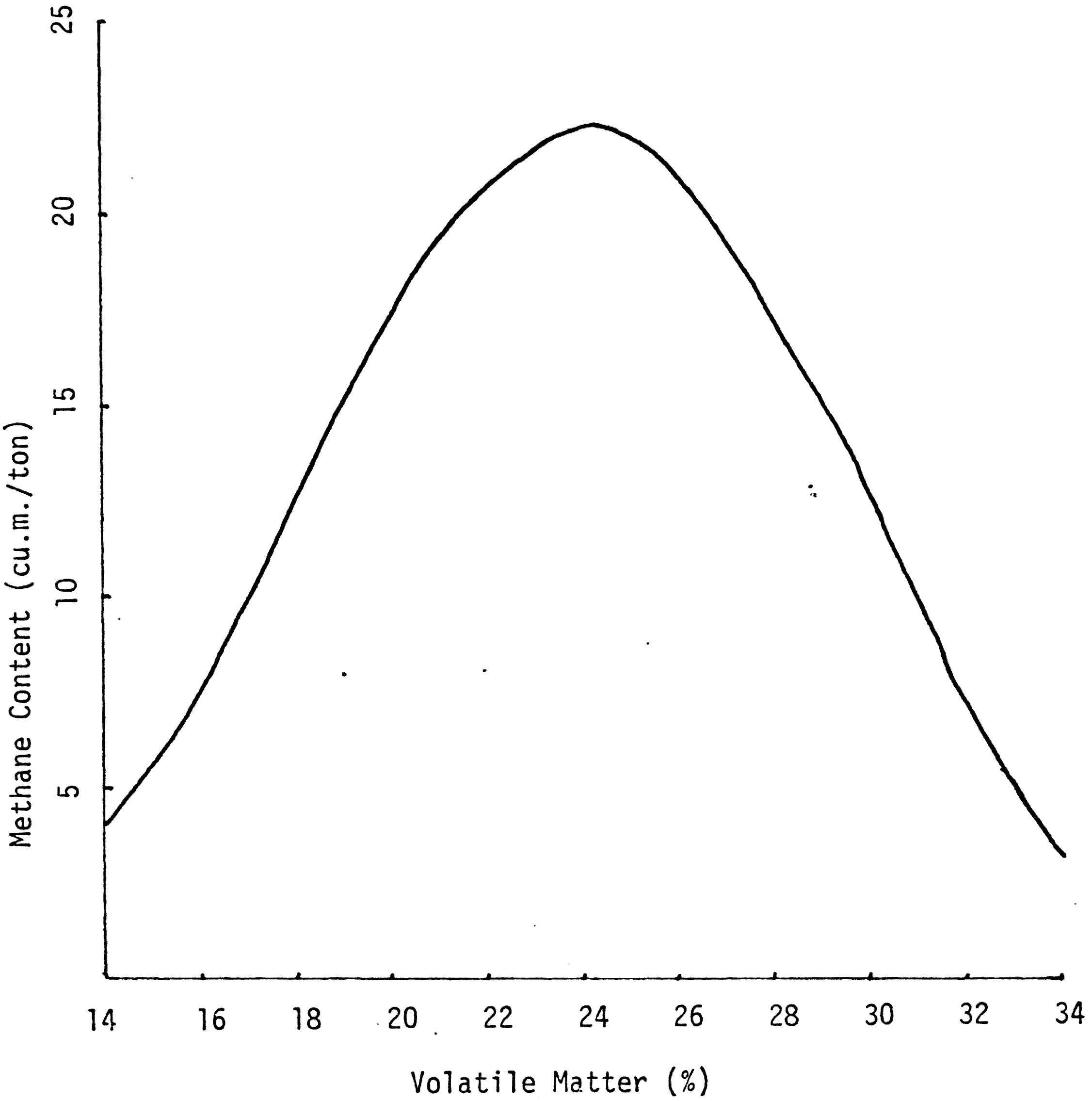

Figure 2: Graph of methane concentrations vs. volatile matter content (20)

these impermeable layers have been known to contain more methane than lower levels immediately below them.

5. Physical characteristics of the coal : Methane occurs in the coal seam by absorption in its molecular structure, adsorption on internal surfaces, compression in pore spaces and by solid solution. As the depth increases, the gas compressed in the pore spaces become more important than that absorbed. The adsorption capacity of coal increases with increasing rank, which in turn is related to the physical properties of the coal.

6. Igneous intrusions : Igneous intrusions form impervious layers or barriers and prevent escaping of gas. At the same time, surrounding rocks form weak or crushed zones due to the intrusions, which form channels for migration and local concentration of gas. Igneous activity is related to tectonic conditions and gives rise to increased degree of coalification of seams in the area. As a result, zones of igneous activity may correspond with zones of high methane concentrations in the area.

There are a number of methods practised to determine the insitu methane content of coal seams. They can essentially be classified as direct, indirect, and estimation methods. These three methods have been detailed below :

3.1 The Direct Methods

In 1967, Bertard, Bruyet and Gunther (1), in France, devised a method for determining the desorbable concentration of gas in coalbeds. This method, the direct method, involves the direct sampling of coal followed by a measurement of methane in the laboratory.

The desorbable concentration of gas in coal is the difference between the gas concentration under insitu conditions and the residual concentration after complete relief. Thus, to measure the desorbable concentration, an area in the mine must be chosen which has not been destressed due to mining.

The method of determination consists of three measurements as detailed below :

1. The Lost Gas : This is the gas desorbed from the coal sample between the time the sample is extracted from the coal seam and the time it is sealed in a container. This lost gas is designated as Q1.

2. The Desorbed Gas : This is the gas desorbed from the sample into the enclosed space of the container. This desorbed gas is termed Q2.

3. The Residual Gas : This is the gas released when the sample is crushed in the laboratory at atmospheric pressure. This residual gas is termed Q3.

Thus, the total quantity of desorbable gas in the coal is the sum of Q1, Q2 and Q3.

<u>Measurement of Lost Gas (Q1)</u>: Experimental studies by Sevenster (18) has shown that the volume of gas desorbed from a coal sample is proportional to the square root of the time over which desorption takes place. Hence, the desorption equation takes the form :

$$Q = k * \sqrt{t}$$

where,

Q = Volume of gas desorbed

t = Time during which desorption takes place

k = Constant, to be determined

The coefficient 'k' is determined by using a desorption meter (Figure 3). Let 't1' be the time elapsed between the moment the sample is extracted from the seam and the moment it is enclosed in the desorption meter. It is left in the desorption meter for a length of time equal to 't1', during which time, the sample desorbes a certain amount of gas which is calculated by the following equation, and is designated as 'q'.

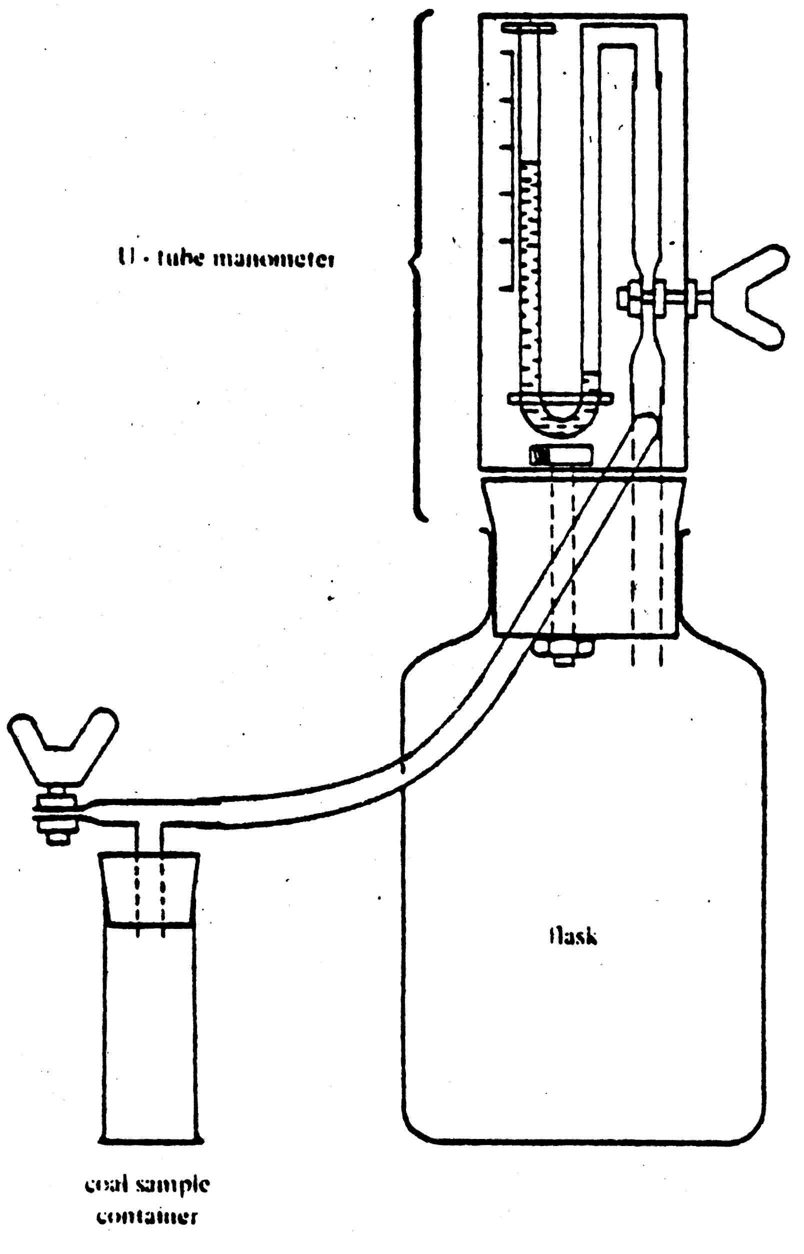

Figure 3: A Desorption meter (1)

Since the desorption takes place within the desorption meter, it occurs by means of pressure rise at constant volume.

If,

V = Volume of the flask

ΔP = Pressure rise

Pf = Pressure condition of the working,

Then,

$$q = V(\Delta P/Pf)$$

The quantity of gas 'q' desorbed between the instants 't1' and '2*t1' can also be expressed as :

$$q = k*\sqrt{(2*t1)} - k*\sqrt{t1}$$

At the end of this operation, the sample is quickly enclosed in its transport container.

The quantity of lost gas 'Q1' can be expressed as :

$$Q1 = k*\sqrt{(2*t1)}$$

Combining the above two equations :

$$Q1/q = [k*\sqrt{(2*t1)}] / [k*\sqrt{(2*t1)} - k*\sqrt{t1}]$$

$$= \sqrt{2} / [\sqrt{2} - 1]$$

Hence,

$$Q1 = q*(2+\sqrt{2})$$

Q1 is hence expressed in conditions of temperature and pressure of the sampling site.

Measurement of Desorbed Gas (Q2): Two methods were used by Bertard et. al. to measure Q2, as explained below :

First Method : The coal sample is transported in a sealed container. The container is a polythene flask equipped with a flexible polyvinyl tube, closed by a Mohr's clip (Figure 4). Before the sample is enclosed, the flask must be squeezed several times, so that, the methane content in it is initially the same as that of the sampling site.

Let

V = Volume of the container

X0 = Initial methane percentage in the flask

X = Methane percentage in the flask when it is opened in the laboratory for crushing

The initial volume of methane in the container under conditions of temperature and pressure of the sampling site is equal to V*X0.

After a volume Q2 (to be measured) of methane has been released into the container during transport, the total volume of methane under atmospheric pressure and temperature conditions is equal to X*(V + Q2).

This can also be expressed as : (V*X0) + Q2

Therefore, equating :

$$X*(V + Q2) = (V*X0) + Q2$$

Hence,

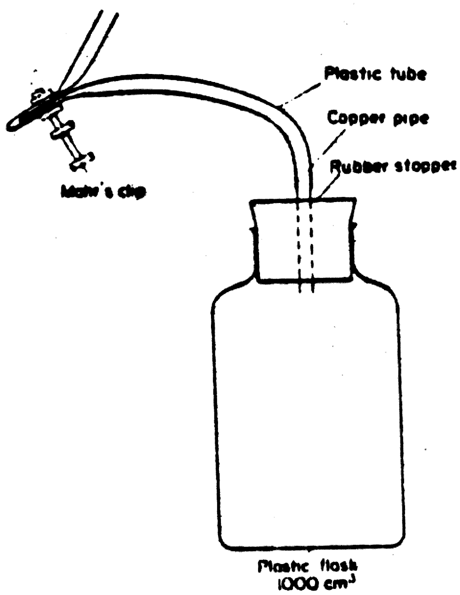

Figure 4: The sealed container for the measurement of desorbed gas (1)

$$Q2 = V*(X - X0) / (1 - X)$$

Multiplying both the numerator and denominator by (1 + X) and neglecting the resultant denominator (since X is small compared to 1), the equation becomes :

$$Q2 = V*(X - X0)*(1 + X)$$

Thus Q2 may be calculated.

Second Method : In this case, the coal sample is transported in a test tube, as shown in Figure 5. The volume between the two sintered glass disks is filled with water. The coal sample is placed above the upper sintered glass disk. When the rubber stopper is in place, water does not flow across the lower disk.

When the coal desorbes some amount of methane, it creates an excess pressure in the upper chamber and drives out an equivalent amount of water. The volume between the initial and final volume of water can be read off on a calibrated level reader, graduated in cubic centimetres.

Let

H0 = Level read immediately after the sample is introduced into the test tube at the sampling site

H1 = Final level read after being brought to the laboratory

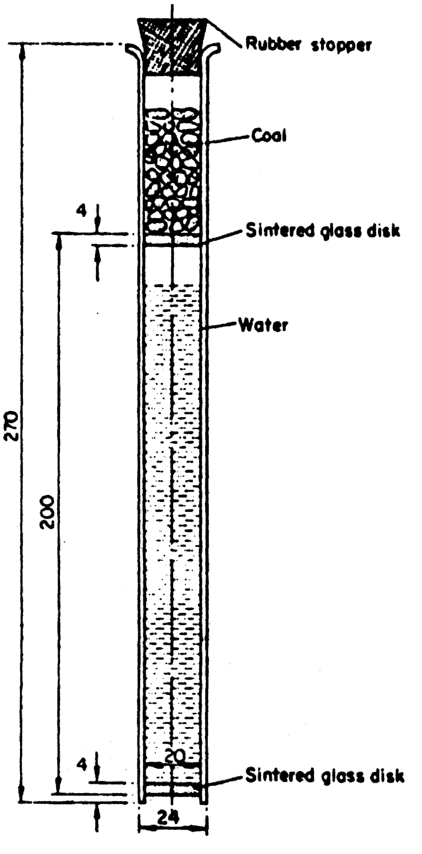

Figure 5: The glass test tube for measurement of desorbed gas (1)

Pf, Tf = Pressure and temperature of the sampling site

Pj, Tj = Atmospheric pressure and temperature of the reading point

The quantity of desorbed gas Q2 can then be expressed as :

$$Q2 = H1*(Pj/Pf)*(Tf/Tj) - H0$$

Thus, Q2 has been expressed under temperature and pressure conditions of the sampling site.

Measurement of Residual Gas (Q3): The sample is crushed in a metal cup and the quantity of gas released (Q3') is measured in a graduated test tube inverted over a pan of water. Therefore, the residual gas, (Q3), expressed under conditions of temperature and pressure of the sampling site is :

$$Q3 = Q3'*(Pj/Pf)*(Tf/Tj)$$

The total desorbable concentration 'Q', per unit weight of the coal sample is hence the sum of Q1, Q2 and Q3, divided by the weight of the sample.

Desorbable concentration is always expressed in terms of pure coal and hence, a correction for ash is applied to the weight of the sample.

The analysis of ash is usually underestimated, due to the evaporation of certain mineral substances, e.g. carbonates. Therefore, a correction factor is applied to the measured ash content, which, in general practice is taken to be 1.1.

Let

m = Weight of coal sample

c = Percentage of ash content measured

Thus, weight of clean coal equals $m*(1 - 1.1*c)$

For technical reasons, the mass of the crushed coal sample must be of the order of 10g.

Thus, the total desorbable gas concentration of the coal is :

$$Q = (Q1 + Q2 + Q3) / [m*(1 - 1.1*c)]$$

In 1973, Kissell, McCulloch and Elder (14) developed a variant of this above method, in which, cores were obtained from boreholes and a graphical procedure was applied to determine the lost gas.

This method has been superseded, in 1975, by a further improvement devised by McCulloch, Levine, Kissel and Deul (15). In this case, both the lost and residual gas are determined graphically. This last method has been described below.

The method is used to determine the methane content of coal in a virgin coal bed, since all holes are drilled to the coal seam from the surface. The hole may be cored from the surface or drilled to the top of the seam and then cored. Once cored, the corebarrel is removed quickly and the core placed in an airtight container to minimize lost gas.

Measurement of Desorbed gas: The sealed container with the coal sample within it is connected to an inverted graduated cylinder filled with water(Figure 6). When the valve on the container is opened, methane flows into the cylinder until atmospheric pressure is attained in the container. The water levels before and after the release of gas are read, and the difference gives the desorbed methane. The valve is then closed until the next reading. Initially the emissions are high and readings must be taken frequently. Within a few days, the desorption rate becomes low enough to require only one reading per day. The date, time and volume of gas released after each reading are recorded. This desorption is allowed to continue for several weeks until the measured desorption rate is below 0.05 c.c./g for five consequtive days.

Calculation of Lost Gas: The core sample begins to give off gas before it is placed in the container. The amount of gas given off depends on the drilling medium and the time required to get the core into the container.

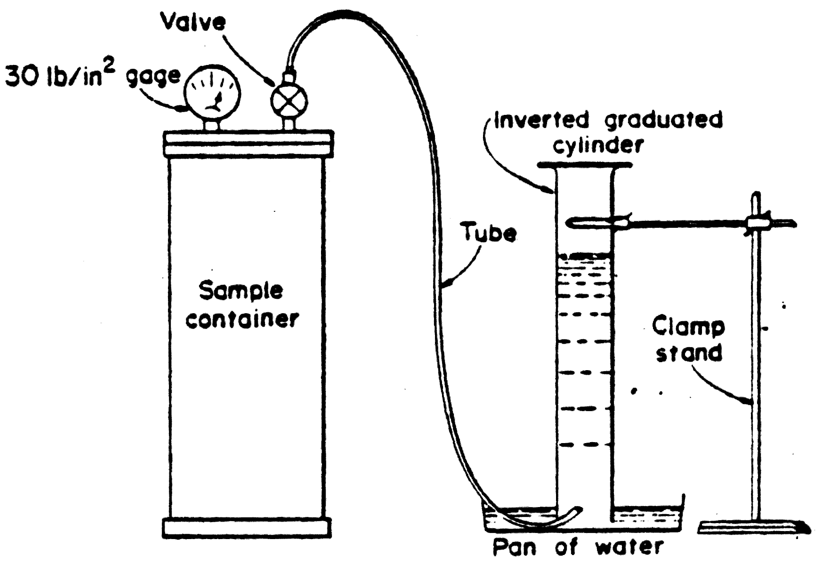

Figure 6: Sample container, gas emission measured by water displacement (14)

If air is used as the drilling medium, then it is assumed that the coal begins to give off gas immediately upon penetration by the corebarrel; in the case of water or mud, desorption is assumed to start when the core is halfway out of the hole; i.e., when the gas pressure is assumed to exceed that of the hydrostatic pressure.

As has been stated earlier, experiments conducted by Sevenster (18) show that the amount of desorbed gas is proportional to the square root of the desorption time. A plot of the total emission after each reading versus the square root of the time during which the sample was desorbing, gives a straight line (Figure 7). After sometime, the points on the graph tend to veer off to the right.

As shown in Figure 8, if the straight line plotted (starting at a point on the X-axis equal to the square root of the lost gas time) is extrapolated backwards to intersect the Y-axis (desorbed gas), the intercept on this axis gives the lost gas.

Estimation of Residual Gas: Even after the rate of desorption becomes less than 0.05 c.c./g, the coal still contains some residual gas. The amount of this residual methane depends on the fracture network that defines coal friability. No quantitative relationship exists to estimate residual gas. A graphical procedure is used.

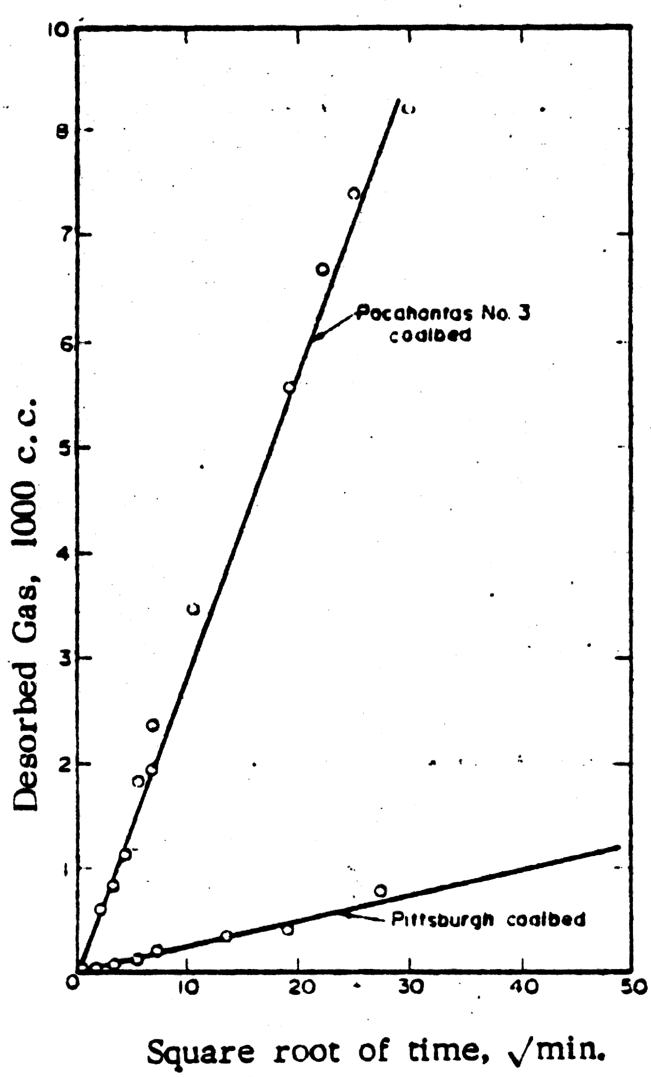

Figure 7: Graph of desorbed gas vs. square root of time (15)

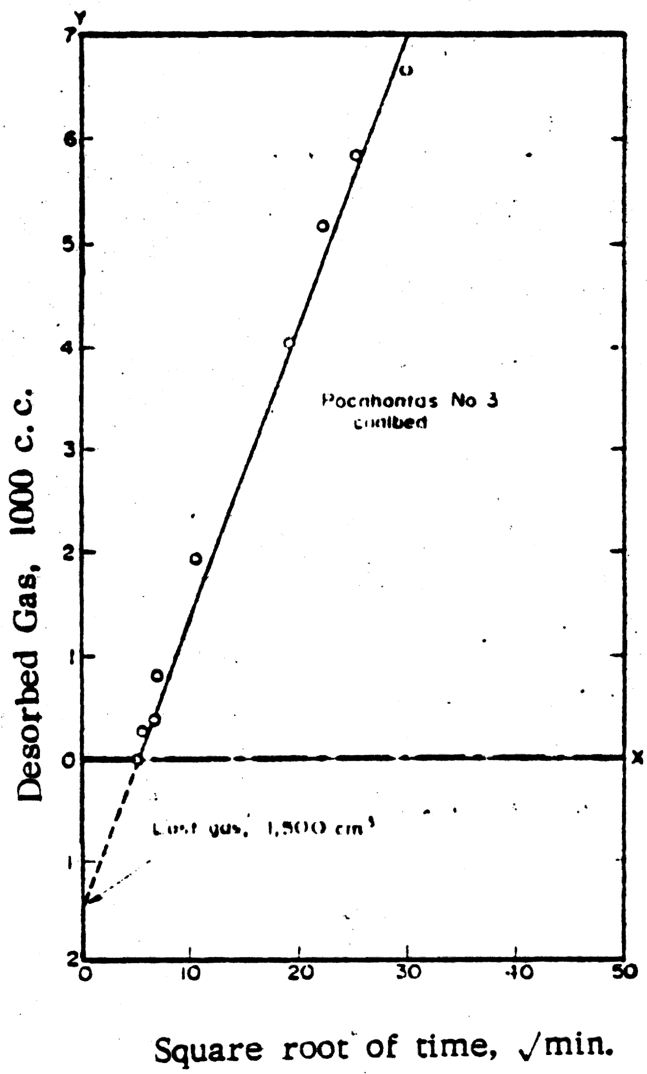

Figure 8: Measurement of lost gas (15)

A number of samples are analysed by gas chromatography and the residual gas figures so obtained are plotted against the sum of the lost gas and desorbed gas figures (Figure 9). As can be seen from this figure, friable coals follow a steeper slope than blocky coals, the reason being, blocky coals release their methane much more slowly and hence contain much more residual gas than friable coals.

Thus, to estimate residual gas, whether the coal is friable or blocky, has to be determined. Friability depends on fixed carbon (Figure 10), Hardgrove Grindability Index (Figure 11), the depth of the coal seam (Figure 12) and the degree of tectonic activity.

The fixed carbon percentage appears to be the best indicator of whether the coal is friable or blocky. As can be seen from the figure, blocky coals tested had fixed carbon less than 57% and friable coals had more than 57% fixed carbon. The Hardgrove index is also a good indicator; in general the indices are less than 70 for blocky coals and more than 70 for friable coals.

Having determined whether the coal is friable or blocky, the lost gas and desorbed gas for the sample under consideration are added and the value on the Y-axis (lost gas + desorbed gas) corresponding to this sum is determined (Figure 9).

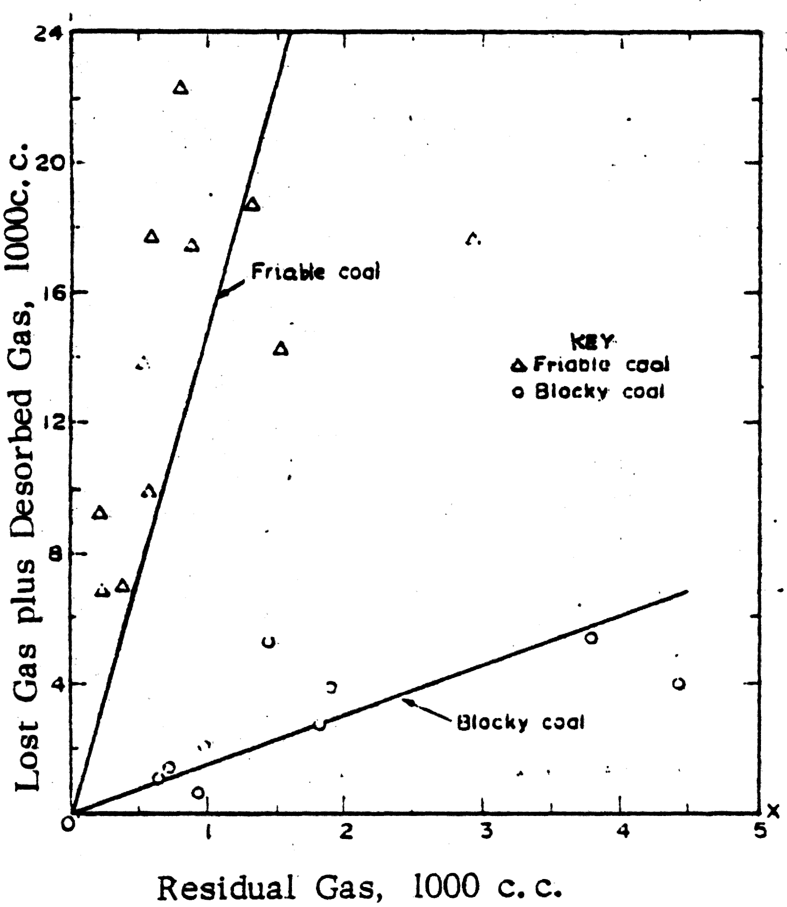

Figure 9: Graph of lost plus desorbed gas vs. residual gas (15)

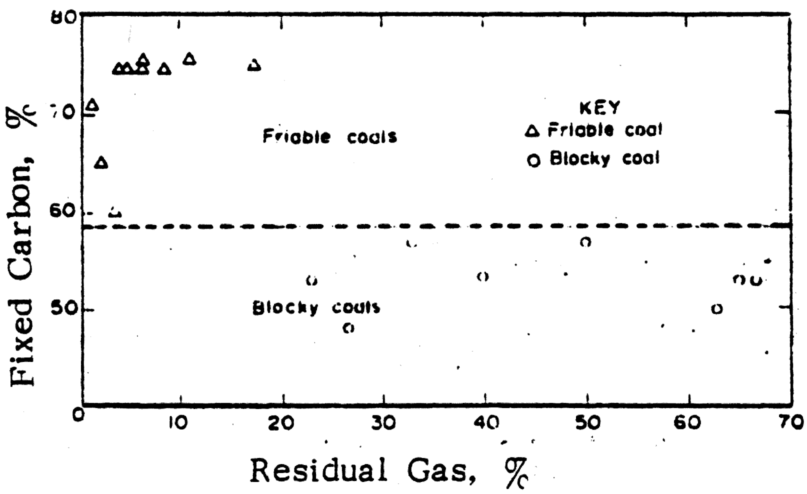

Figure 10: Graph of percent residual gas vs. fixed carbon content (15)

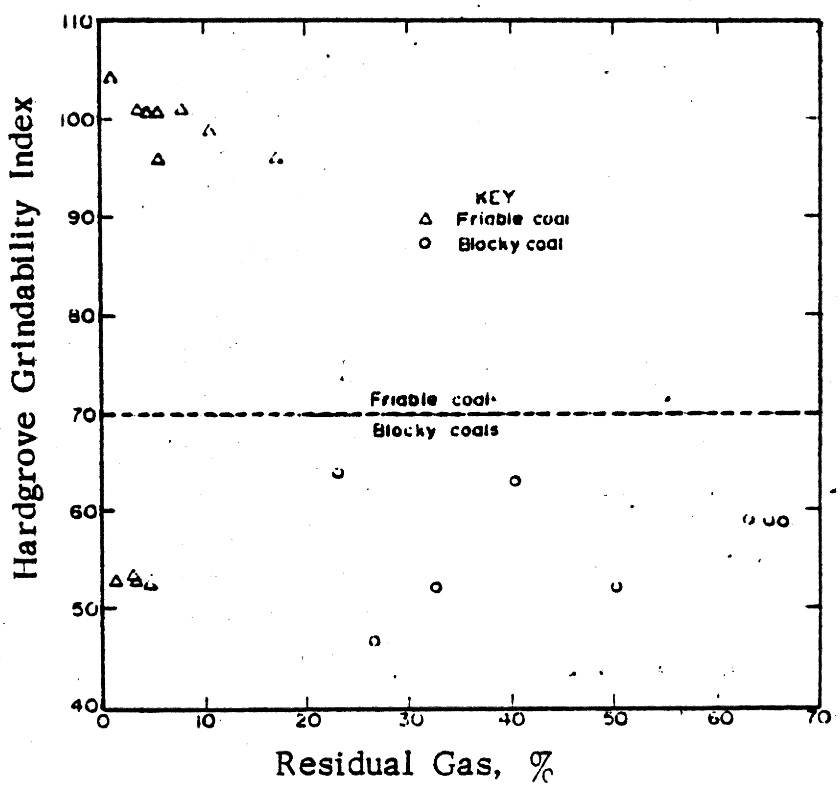

Figure 11: Graph of percent residual gas vs. Hardgrove Grindability Index (15)

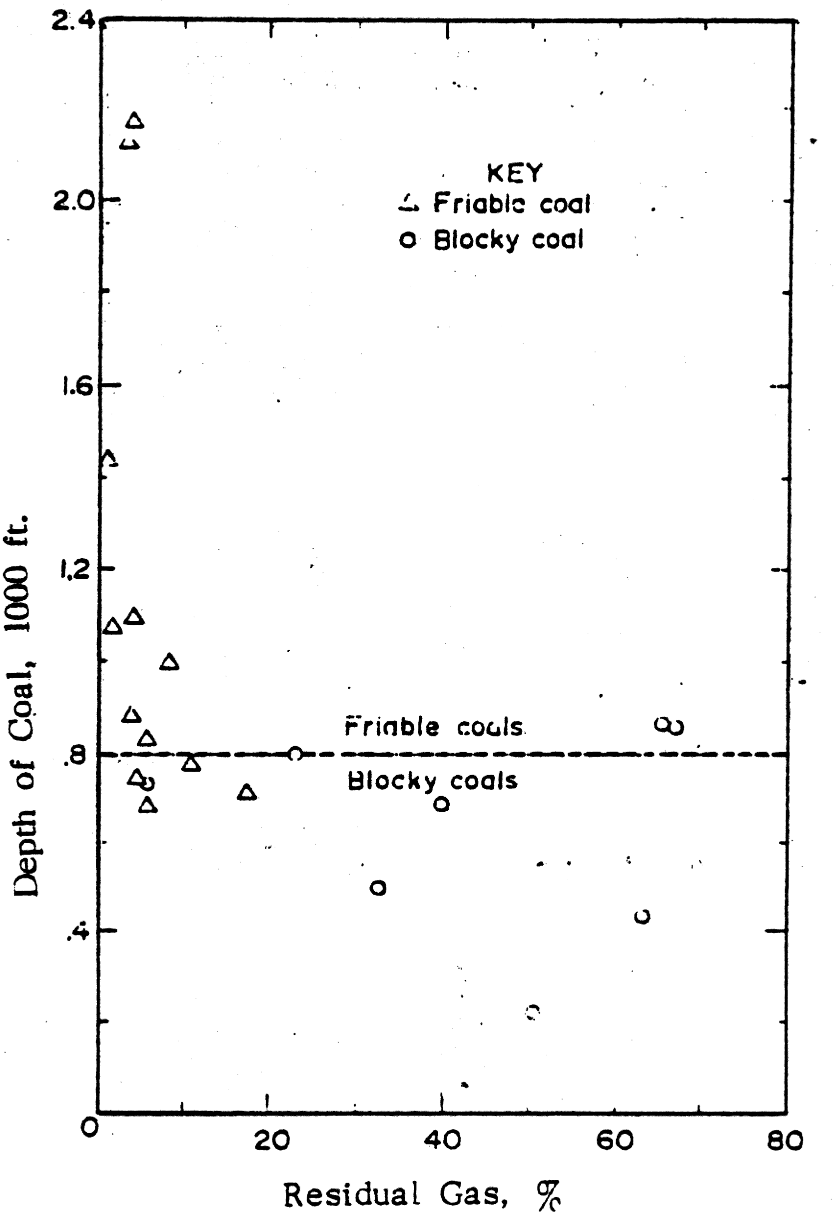

Figure 12: Graph of percent residual gas vs. depth of coal (15)

This line is followed to the corresponding blocky or friable coal line, as the case may be, on the graph. The quantity of residual gas can then be read directly on the X-axis.

The sum of the lost, desorbed and residual gases gives the total methane content of the sample. The total methane content in the area is determined by multiplying the gas content determined by the tonnage expected in the area.

3.2 The Indirect Method

The indirect method was developed in the USSR by Ettinger (6) to overcome the problems associated with the direct methods.

The method involves firstly a measurement of the seam gas pressure and secondly a laboratory determination of the quantity of methane held by this particular coal at this pressure.

A borehole is drilled into the coal seam from either underground or surface. The seam gas pressure measuring apparatus used by Ettinger is then lowered into the borehole using ordinary drill rods. After the apparatus has reached the top of the coal seam, a pressure of the order of 2000 - 2500 kg. per sq. cm. is applied to break certain adjusting pins, which causes a rubber collar to expand and press against the walls of the borehole, thus isolating and sealing the 'face' area of the borehole from the rest of the latter. The hole must be made airtight by creating a pressure equal to the weight of the instrument plus a pressure of 2000 - 3000 kg. per sq. cm. created by the drill.

The buildup of gas pressure is now measured by a manometer for an extended period of time, until equilibrium is reached. This equilibrium pressure is taken as the in-seam gas pressure. The temperature of the coal seam is measured from the readings of a thermometer located in the manometer.

This measured pressure is applied to the predetermined methane desorption isotherms for the particular coal and the methane content thus determined.

Where it is impossible to determine the adsorption capacity of the coal directly, it can be approximately calculated by the following empirical formula :

$$X = \frac{65.5 * (100 - A - W)}{[\, a/p + (c/V^{0.146}) * 100 * e^{n} * (1 + 0.31 * W)}$$

Where,

X = Adsorption methane capacity of coal (cu.m./ton)

65.5 = Conventional maximum adsorption capacity of coal, where, V=1%, W=0%, t=0° C & c=1 cu.m/t of combustible matter

A = Ash content (%)

V = Volatile matter content (%)

W = Moisture content (%)

t = Temperature (C)

a = A constant

b = A constant

p = Pressure of methane (atm.)

n = A temperature factor, determined from the equation :

$$n = \frac{0.02 * t}{0.993 + 0.007 * p}$$

This empirical equation is valid for the determination of the adsorption capacity of coals with a moisture content less than 3%.

If it is possible to obtain samples of the coal under consideration, adsorption tests are performed on the samples and the adsorption isotherms are drawn. A sample of coal is put in a sealed container of known volume. The container is then evacuated completely. Then the sample in the container is left in a methane atmosphere for three to ten days until adsorption equilibrium has been achieved. The pressure and temperature at which this is done is also measured. Thus, the volume of methane adsorbed at a certain temperature and pressure is obtained. Varying the conditions of adsorption gives the adsorption isotherms.

As was mentioned earlier, the measured seam gas pressure when applied to this isotherm, gives the methane content of the coal.

3.3 The Estimation Method

The estimation method of methane content determination has been devised in the U.S. Bureau of Mines by A.G. Kim in 1977 (13).

Most of the gas in coal is adsorbed on the internal surfaces of the micropores in the coal. The adsorptive capacity of coal increases with coal rank. Pressure is another critical parameter affecting the adsorptive capacity of coal for methane. These relationships are depicted graphically by an adsorption isotherm, which is a plot of pressure versus the adsorptive capacity of coal for methane, at constant temperature (Figure 13). Empirically, adsorption isotherms are described by the equation :

$$V = K*P^n$$

Where,

V = Volume adsorbed (c.c./g of moisture and ash free coal)

P = Pressure (atmospheres)

K = A constant (c.c./g/atm.)

n = A constant

The adsorptive capacity of coal decreases with increasing temperature (Figure 14) and the adsorption equation becomes :

$$V = K*P^n - b*T$$

Where,

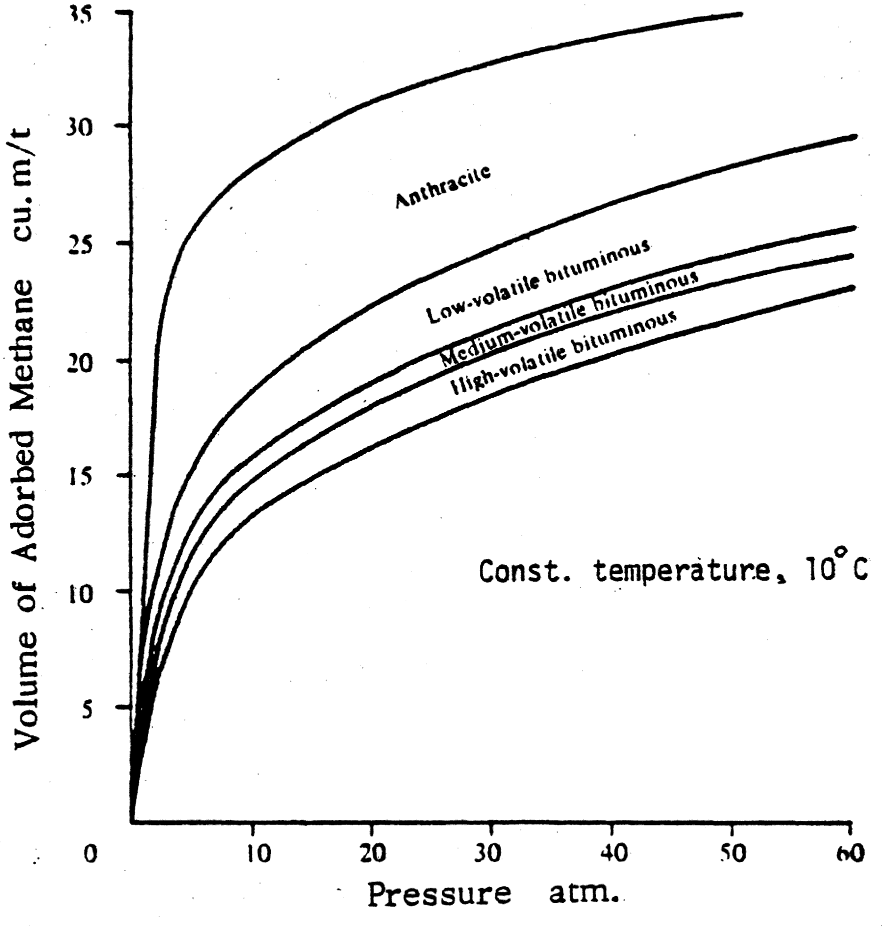

Figure 13: Variation of methane adsorption isotherm with coal rank (4)

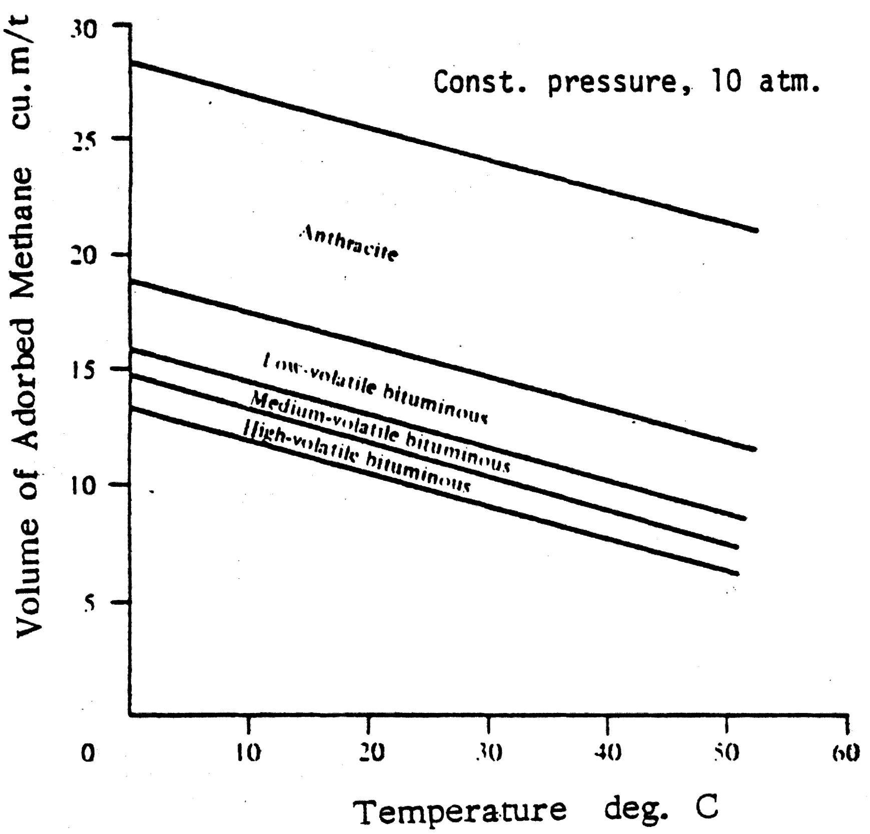

Figure 14: Variation of methane adsorption capacity of coal with temperature and rank (4)

T = Temperature (deg. C)

b = A constant (c.c./g/deg. C)

To determine K and n, the above equation is transformed to a logarithmic form :

$$\log V = \log K + n*\log P$$

A straight line is obtained on plotting 'log V' versus 'log P', with 'log K' as the intercept and 'n' as the slope (Figure 15).

The temperature constant 'b' is determined by plotting 'V' versus 'T' at constant pressure, which also gives a straight line with 'b' as its slope (Figure 16).

The constants K,n and b have been determined from known coals using experimental procedures for dry coal. K and n, when plotted against corresponding fixed carbon percentages, gives straight lines which are described by the following equations:

$$K = 0.25 *FC - 9.41 \quad \text{(reg. coeff. 0.82)}$$

$$n = 0.55 - 0.004 *FC \quad \text{(reg. coeff. 0.86)}$$

Where,

FC = Fixed Carbon percentage

The regression coefficients of these lines show that the equations are in fair agreement with experimental values.

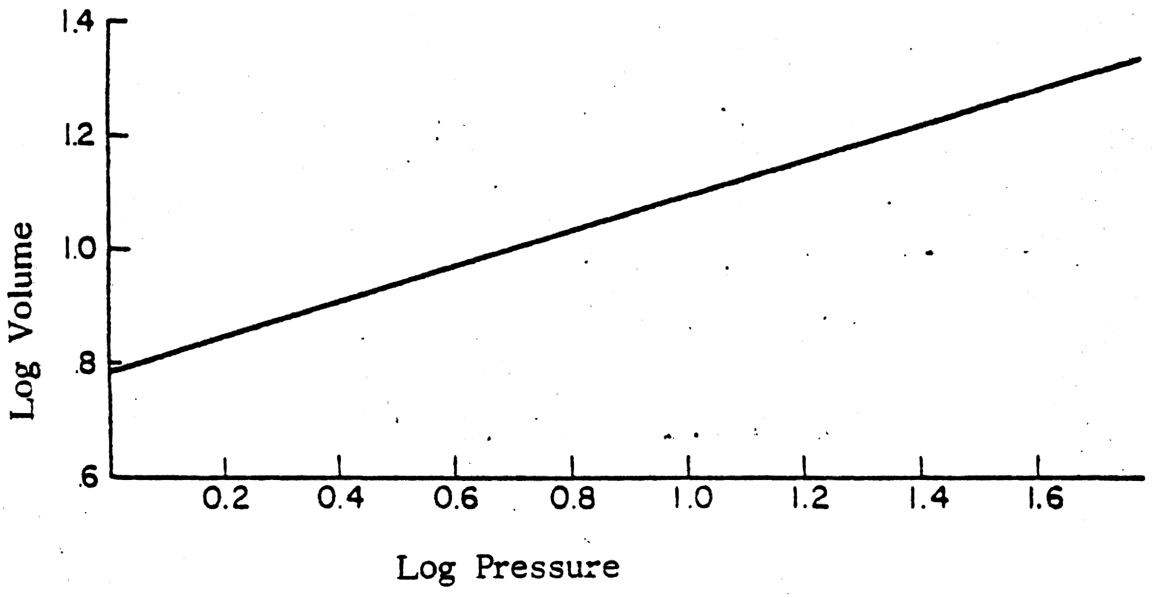

Figure 15: Log-log plot of volume adsorbed vs. pressure (13)

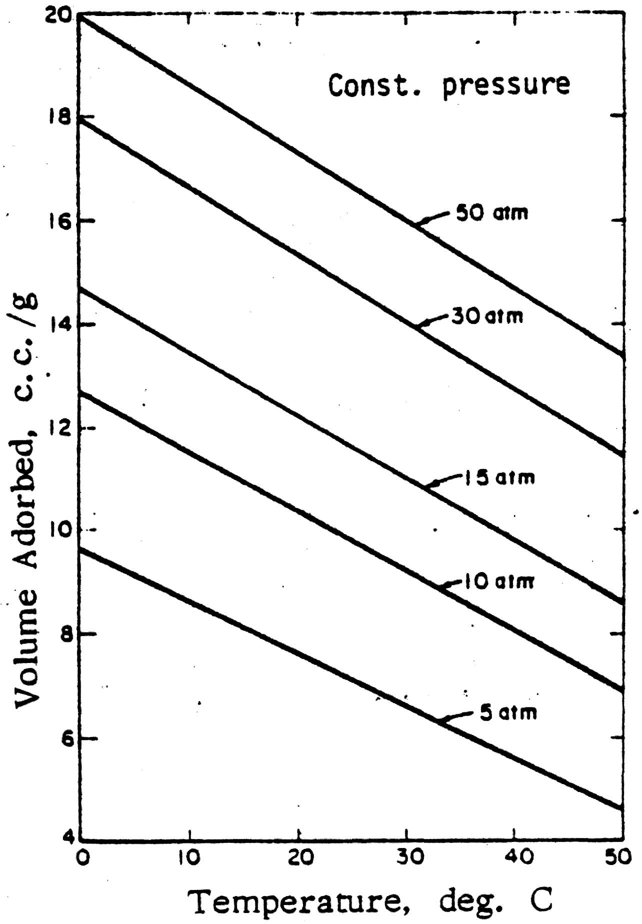

Figure 16: Graph of volume adsorbed vs. temperature (13)

Plotting K versus the ratio of fixed carbon to volatile matter content, (Figure 17), results in a straight line which may be expressed by the following equation :

$$K = 0.79 * (FC/VM) + 5.62$$

Where,

VM = Volatile Matter percentage

The constant n can be related to K, since both are functions of rank, by the following equation :

$$n = 0.39 - 0.013 * K$$

The constant b does not depend on rank. The range of b for the coals studied was found to be 0.11 to 0.18, with an average of 0.14. This value is usually used.

Pressure and temperature are both functions of depth. The pressure 'P' at a given depth 'h', is usually assumed to be hydrostatic and determined by the equation :

$$P_{hyd} = 0.096 * h$$

Where,

Phyd = Hydrostatic Pressure (Atm.)

h = Depth (m)

The experimental values of pressure at various depths are plotted in Figure 18, and, as is evident from the figure, practically all the points are below the corresponding hydrostatic head at those points. From these data, an average pressure gradient of 0.063 atm/m with a standard deviation of ±0.027 has been arrived at.

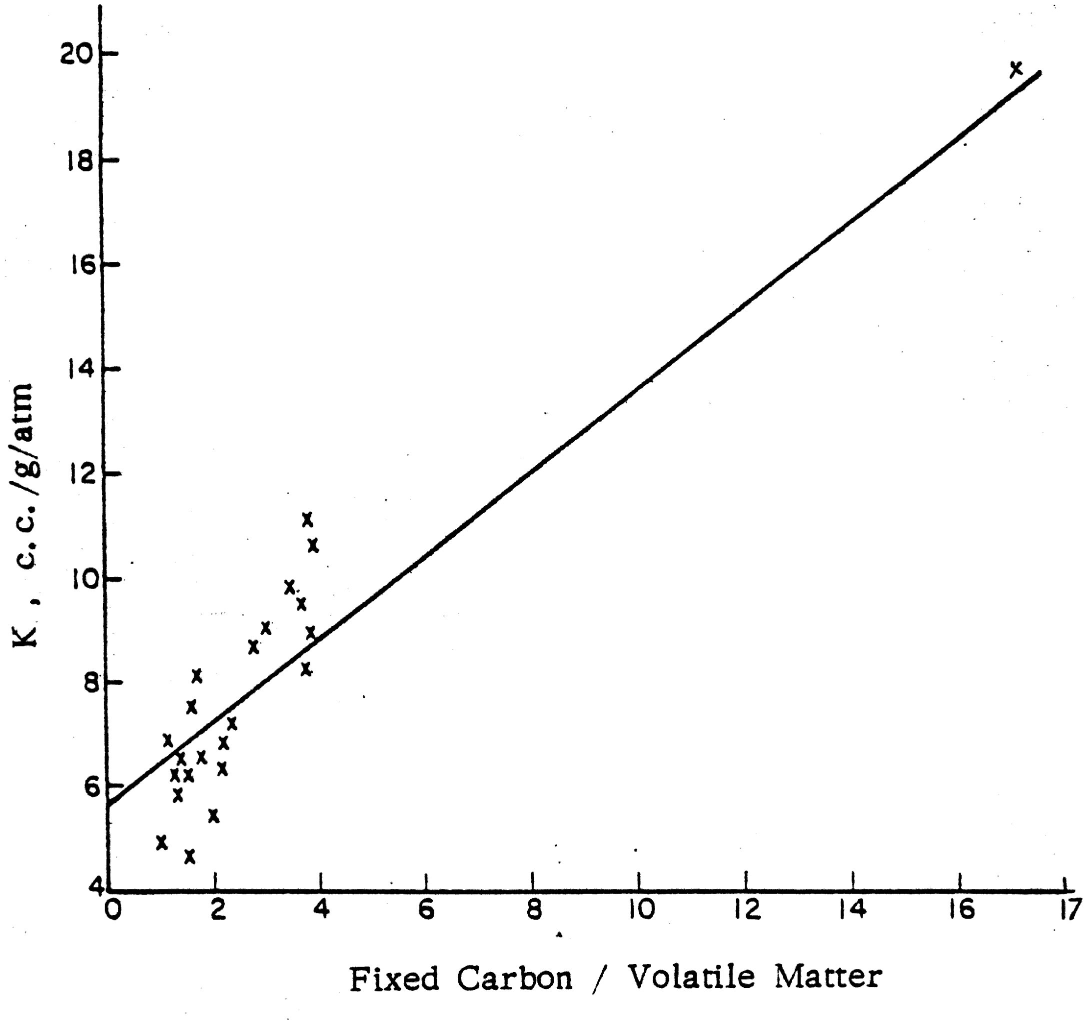

Figure 17: Graph of K vs. ratio of fixed carbon to volatile matter (13)

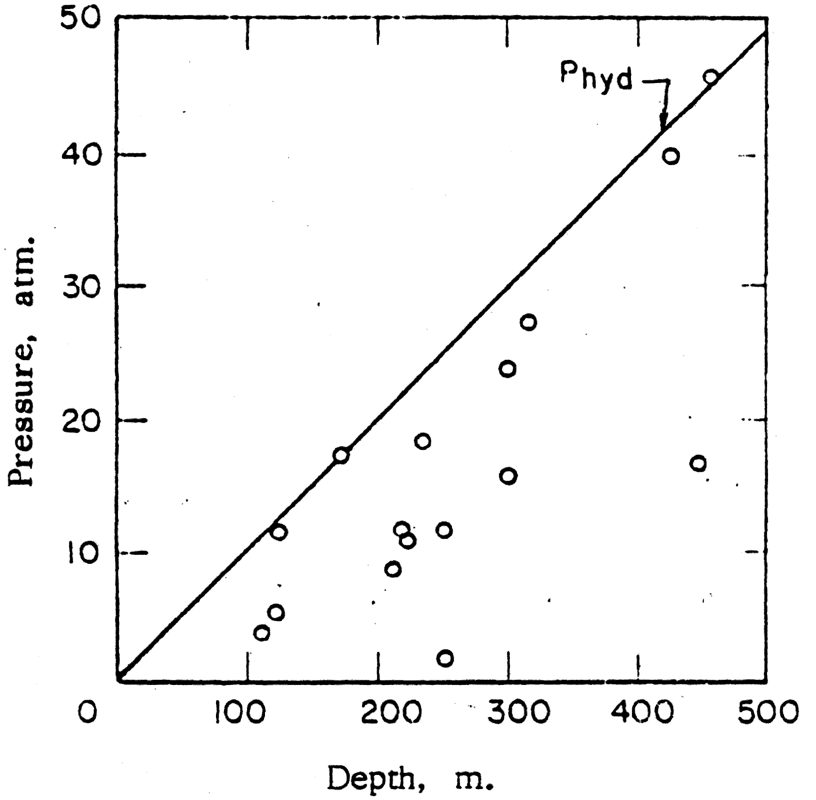

Figure 18: Graph of pressure vs. depth (13)

Where the pressure gradient is known, that value is used. Otherwise, a maximum methane content can be estimated using the hydrostatic head and a more conservative estimate may be obtained using the average figure stated above.

The temperature at a given depth may estimated by using the geothermal gradient. An average and commonly used figure for the geothermal gradient is 1.8 deg.C per 100m depth. Ground temperature is also variable, but an average value of 11 deg.C is used.

Hence, the temperature at a certain depth is estimated as :

$$T = 1.8 * (h/100) + 11$$

Where,

T = Temperature (deg. C)

h = Depth (m)

The presence of water has a considerable effect on the adsorption capacity of coal and must also be considered in the estimation of adsorbed methane in the coal. Moisture in coal reduces its capacity to adsorb methane as shown by Khodot (12), Figure 19. Joubert's (11) investigations suggest that only adsorbed water affects the methane adsorption capacity of coals. The other significant feature of Joubert's isotherms (Figure 20) show a critical value of the moisture content, beyond which, any increase in moisture content does not affect the methane adsorbed.

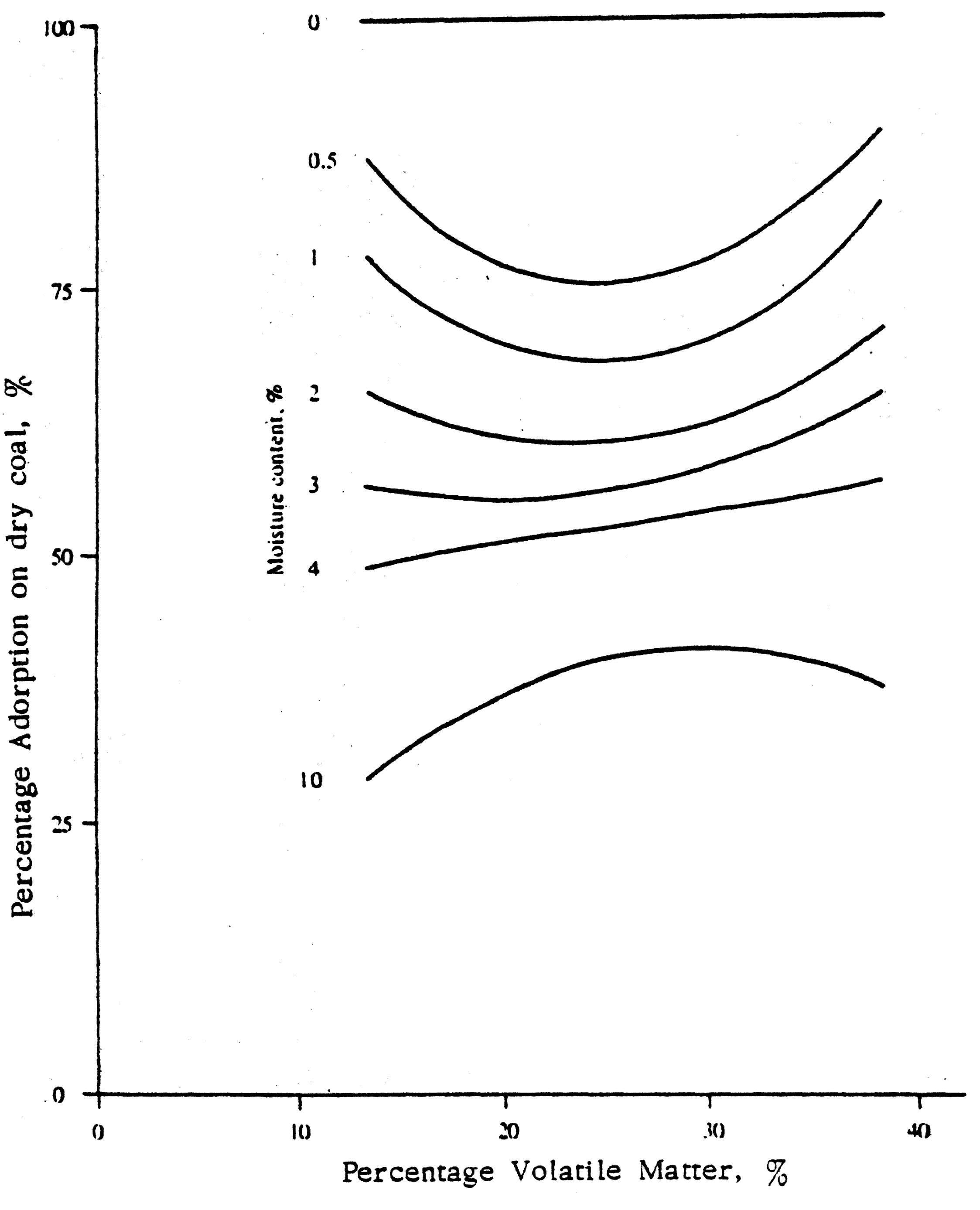

Figure 19: Effect of moisture content on the adsorption capacity of coals of various volatile contents (12)

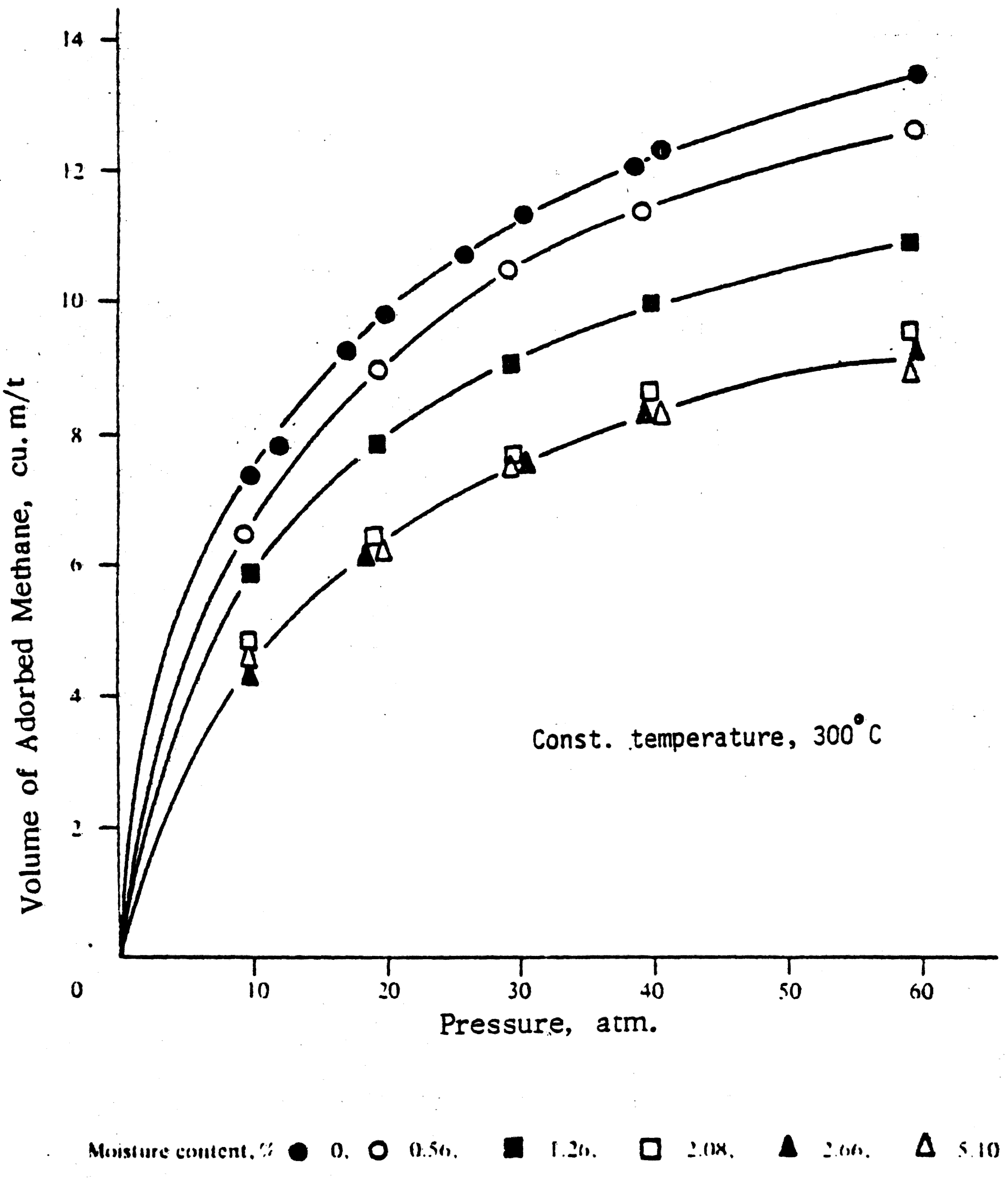

Figure 20: Methane adsorption isotherms vs. moisture contents (11)

Joubert (10) shows that this critical value is dependant on the oxygen content of the coal (Figure 21).

The maximum reduction (R), at or above the critical moisture content can be expressed as :

$$R = [1 - (Vw/Vd)]$$

Where,

Vw = Adsorptive capacity of wet coal for methane

Vd = Adsorptive capacity of dry coal for methane

Then,

$$[1 - (Vw/Vd)] = C1*X + C2$$

Where,

X = Coal oxygen content

$C1, C2$ = Constants

C1 and C2 have been found to have the values 5.58 and 8.37 respectively.

In general, for most high rank coals, the mininmum volume of methane adsorbed on wet coal is between 55 to 85 percent of the volume adsorbed on dry coal. For coals where enough data is not available, it is reasonable to assume that moisture in coal reduces its capacity to adsorb methane by about 25%. The ratio 'Vw/Vd' is used in the gas adsorption equation and a value of 0.75 is usually applied to it.

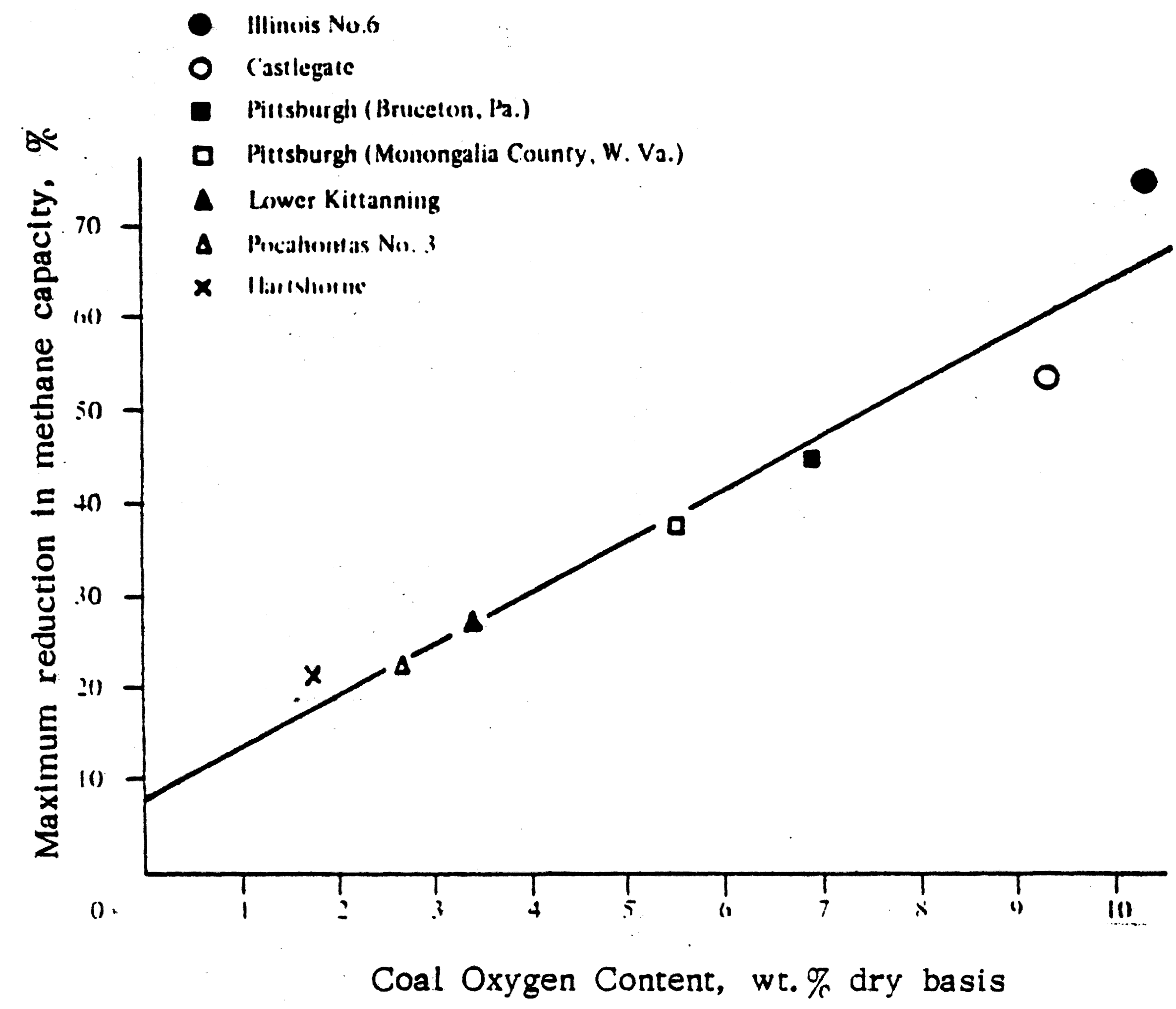

Figure 21: Maximum reduction in methane adsorption vs. coal oxygen content with moisture content above critical values (10)

As stated earlier in the adsorption equation, the volume of adsorbed gas estimated was for moisture and ash free coal. The gas content of insitu coal is estimated by introducing a factor in the gas adsorption equation which considers the moisture and ash content in the coal.

Incorporating all the factors discussed above, the general equation for estimating the gas content of insitu coal becomes :

$$V = \frac{(100 - \%moisture - \%ash)}{100} * \frac{Vw}{Vd} * [K*P^{n} - b*(1.8*h/100 + 11)]$$

The total gas resource of the area may then be calculated by applying the tonnage figures for the area to the methane content estimated as above.

3.4 Evaluation of the Methods

In addition to the different methods detailed above, there are quite a few more. But, all of them follow the same basic principles.

The direct method (and its variants) is the one which is used mostly for the estimation of methane content of coal seams. The method devised by Bertard, Bruyet and Gunther is accurate, but, it suffers from the disadvantage that the determination of residual gas is neither simple nor very accurate. On the other hand the graphical procedure employed by Kissel et.al. is far more easier to use. It obviates the neccesity of bringing the sample to the laboratory, as the results can be calculated in the field.

The indirect method developed by Ettinger, involving the measurement of seam gas pressure, has a problem due to the adverse effect of water in coal strata, which gives a hydrostatic pressure and therefore a misleading borehole pressure reading as shown by Kissel. However, for inseam boreholes, it has been shown by Paul (16) that water and methane pressure can be distinguished from the shape of the graphs of pressure buildup in the borehole (Figure 22). Wet drilling is therefore disadvantageous on account of the significant effect of moisture on the methane adsorption of coal.

The direct method is more convenient and less expensive than the indirect method. Drilling ahead of mining is a routine procedure and therefore, sampling may not involve additional drilling. After a series of comparative measurements using both the direct and indirect method, it has been shown by Curl (4) that, on the average, the results obtained by the indirect method was 3.5% higher than those obtained by the direct method.

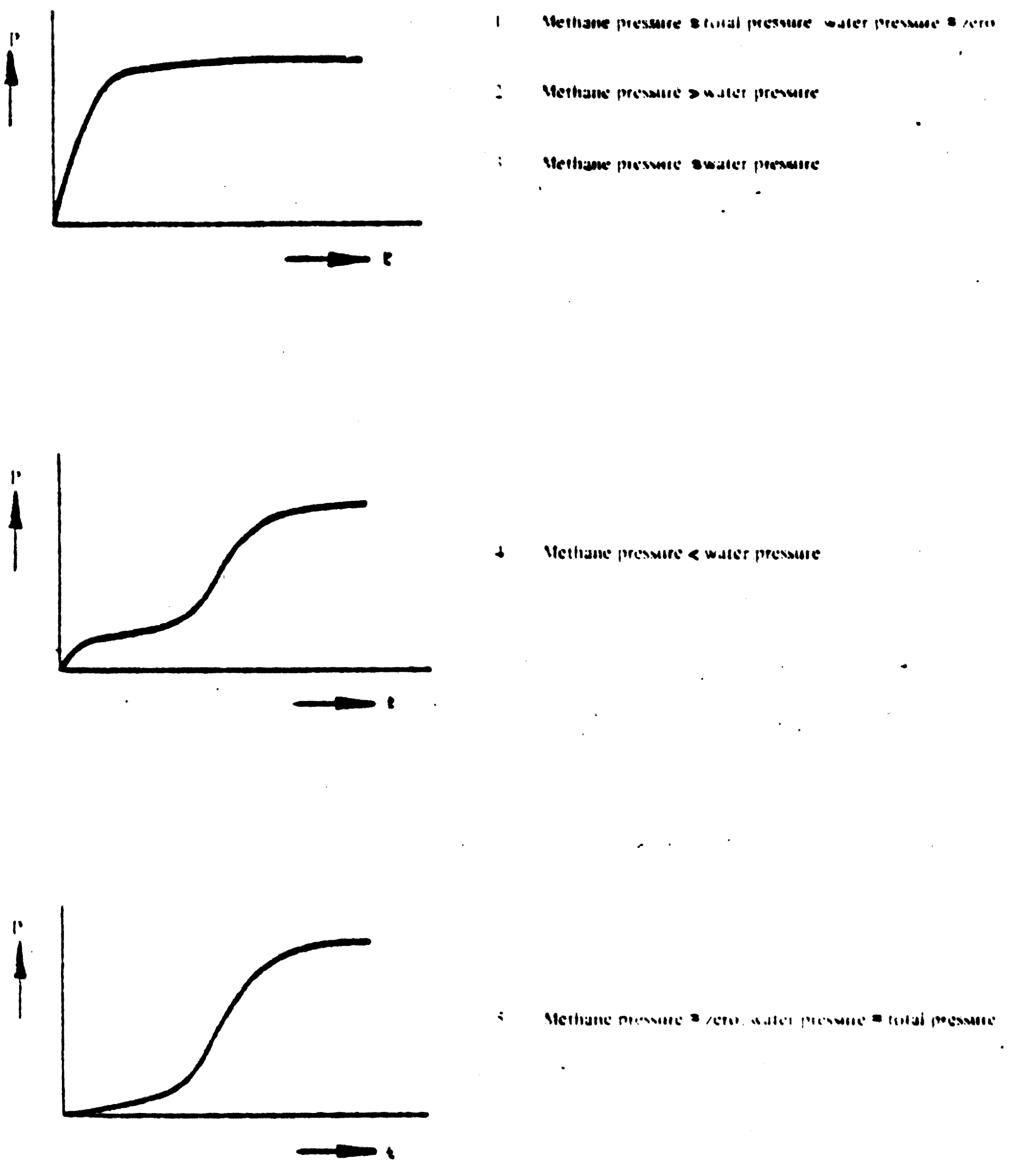

Figure 22: Typical forms of pressure - time curves in boreholes into coal seams (16)

In seams where workings already exist, the methane content can be readily and easily determined by the direct method, but, in a distant seam, accesible only by a borehole, the indirect method gives good results.

All the above methods are relatively simple and sufficiently accurate, but, all require the drilling of a hole, and the data thus obtained apply only to a particular coal sample. The estimation method, devised by Kim, estimates the methane content from a predetermined relationship between the gas content, coal rank and depth. However, it provides a more general estimate.

The direct method is said to be ±30% accurate and most of the values estimated from the estimation method have been shown by Kim to be within this 30% limit.

Although the methods described are normally used to determine the gas content of coal seams, they are equally suitable for the determination of methane content in other gas bearing strata of low permeability.

Chapter IV

METHANE ESTIMATION IN THE RICHMOND COAL BASIN

Almost all the methods of methane estimation in coal seams are dependant on actual sampling of the coal and measurement of the methane given off. However, the purpose of the project was to estimate the methane potential in the Richmond Coal Basin by using existing data. Therefore, the direct and indirect methods, which require sampling, are not applicable. Therefore, the estimation procedure developed by Kim is used in this study. As explained in Chapter III, the estimation procedure requires knowledge about the amount of coal resources, depth of coal seams and the quality of coal, which are studied in the following sections.

4.1 The Coal Resources of the Basin

Even though the Richmond Coal Basin has a long mining history, remarkably little is known about the coal resources. The data present on the Basin is very irregular and therefore it is impossible to estimate the coal resources seam by seam. An attempt has been made here to estimate the coal resource of the entire basin.

4.1.1 Historical Resource Estimates

A literature survey indicates that Heinrich (9) and Shaler and Woodworth (19) are the only sources that provide an estimate of the recoverable coal in the area.

Heinrich does not calculate the reserves, but states that the basin covers an area of 189 square miles. Allowing for deteriorated localities and pinched places, he believed that at least 151.2 square miles are underlain by coal in the basin. He also mentions two workable coal seams, the upper one, twenty to forty feet or more and the lower one, three to five feet, in thickness. On a conservative basis, assuming the top seam having a thickness of 20 feet and the lower seam 4 feet, it may be expected that there is at least 24 feet of coal throughout the entire basin. Heinrich gives a density of 2075 lbs/cu.yd. or 76.85 lbs/cu.ft. of coal. Working from this average width of 24 feet of coal and density of 76.85 lbs/cu.ft., the tonnage from 151.2 square miles comes out to be 3.887 billion tons.

Heinrich also states that an estimate of 11,295 tons per acre were removed from an average of 500 acres. Working from this figure and assuming 55% recovery (due to losses in room and pillar mining), the insitu tonnage would be 20,536 tons/acre. In the total area of 151.2 square miles, as mentioned above, a figure of 1.987 billion tons of coal may be estimated.

Therefore, in calculating the basin's resources using Heinrich's figures, an estimated resource of 2 to 4 billion tons is obtained.

Shaler and Woodworth estimate an area of 150 square miles, leaving out the south western area of the basin. They assume a total thickness of 12 feet workable coal. No density is mentioned, but they do arrive at a figure of 12,000 tons per acre recoverable. Using this figure and again assuming 55% recovery, a figure of 2.095 billion tons is obtained.

From the above two estimates, at least 2 billion tons of coal may be expected to be present in the basin, with the possibility of the actual figure being of the order of 4 billion tons.

4.1.2 New Resource Estimates

Using the historical data and the new geological work done on the Richmond basin by the Goodwin (7), a new estimate of the resources has been worked out.

From an extensive literature survey, an average total width of the coal seams at different mines and their corresponding overburden thicknesses were obtained. These are given in Table A-1 in Appendix A.

In addition to the above, working from the available cross sections of the basin from Goodwin's study, coal and overburden thicknesses at certain identifiable points were extrapolated. This was done to supplement the data obtained from the literature survey. For the purpose of these calculations, the total thickness of coal reported at each point, less any partings, have been considered. This is because there is no reasonable correlation between the sections and it is thus impossible to arrive at figures for individual seams.

A coordinate system was defined to identify each point of known overburden thickness or coal thickness respectively. These data were used to draw two contour maps of the basin, one giving the overburden thickness contours and the other giving the coal thickness contours. A computer program called 'The General Purpose Contouring Program', was used to draw the contours. It is a proprietary computer program, available from the California Computer Products, Inc.

In the program, the random data provided is gridded, i.e., the values of the function at the mesh points of a rectangular array are estimated and contours are produced from this gridded data. The spacing of the grid point values are specified by the user depending on the density of the original data points. Once the grid has been specified, the program generates the gridded values from the irregularly spaced values by approximating the function or surface. This approximation process consists of two basic operations : (1) tangent plane or gradient determination using the concept of neighbourhoods, and (2) extension of this information to generate grid values which are weighted based on the distance from the mesh point in question to the various data points.

The overburden and coal thicknesses range from 0 to 3900 feet and and 0 to 60 feet, respectively. An iterative procedure was adopted to arrive at the proper contour intervals in each case, which would suit the purposes of these calculations. Thus, contour intervals of 300 feet for the overburden thickness contours and 10 feet for coal thickness contours were decided upon. Approximations were made in the program so as to draw as smooth contour lines as far as possible. These two contour maps are shown in the Figures B-1 and B-2 of Appendix B. As the number of data points are too few for so large an area, the contour lines show zero thickness in the areas where there are no data points.

As can be seen in the coal thickness contour map (Figure B-2 of Appendix B), there does not seem to be any coal present in the mid-section of the basin. Therefore, the basin has been divided into two sections, namely, the 'North Basin' and the 'South Basin'. The Carbon Hill District, Midlothian District and the Hugenot Springs District are included in the North Basin and the Clover Hill District constitutes the South Basin. Another reason for this division is the analyses of the coals in these two sections, which are significantly different.

These two sets of contours are then superimposed over each other, as shown in Figure B-3 of Appendix B. Areas covered at a particular depth and thickness are determined by planimetering and they are given in Tables C-1 and C-2 in Appendix C. Applying the associated thickness values to each of these areas, volumes covered at that particular depth and thickness are determined.

In order to arrive at the coal resources of the basin, the density of the coal is also needed. For this purpose another survey of the literature was conducted to obtain densities of the coals in the basin. The density figures thus found are given in Table A-2 in Appendix A. The densities seem to be fairly consistent. An average density for each district was determined. From these, average densities for the North and South Basins were calculated as shown in Table 3. These density figures are then applied to the corresponding volumes to calculate the coal tonnages according to their depths from the surface which is given in Table 4. Thus, the total estimated coal resources of the basin come out to be 3.57 billion tons.

On planimetering around the edges of the basin in Figure B-2 of Appendix B, it is found that only 106.104 square miles (Table 4) of area are underlain by coal. Comparing with Heinrich's figures of a total of 2 billion tons of coal in an estimated area of 150 sq. miles, it is seen that a much larger tonnage has been arrived at, although a much smaller area has been considered. This is due to the fact that the coal thicknesses considered in this study are greater, because all coal reported has been considered here. One may recall that a similar tonnage was arrived at, using Heinrich's figures.

4.2 Analyses of the Coal in the Basin

To estimate the methane resources of the basin, the analyses of the coal is necessary. The coals in the basin seem to be variable in quality, ranging from 'natural coke' to fairly poor bituminous coals.

Table A-3 of Appendix A lists all the coal analyses found in the literature. These have been listed by district, and as can be seen from the listing, only the Midlothian and Carbon Hill Districts have a reasonably large number of samples.

TABLE 3

Average Analyses of the Coal (22)

Composition District	Sp.Gr.	Moisture %	Volatile Matter%	Fixed Carbon%	Ash %
Natural Coke	1.335	1.36	12.02	78.17	8.80
Deep Run	1.382	1.79	23.70	65.00	9.25
Carbon Hill	1.315	1.46	26.36	63.18	9.77
Midlothian	1.325	1.60	31.78	56.82	9.55
Clover Hill	1.302	1.56	30.62	58.40	7.90
Hugenot Springs	-	1.95	30.10	62.90	6.43
North Basin	1.321	1.55	28.07	61.32	9.40
South Basin	1.302	1.56	30.62	58.40	7.90

TABLE 4

Areas and Estimated Tonnages

Location	North Basin	South Basin	Totals
Areas	76.3 sq.mi.	29.8 sq.mi.	106.1 sq.mi. *
Depth	m. tons	m. tons	m. tons
0 - 300	195.24	51.93	247.17
300 - 600	181.58	64.81	246.39
300 - 900	155.29	63.29	218.58
900 - 1200	169.12	63.54	232.66
1200 - 1500	104.12	59.24	163.36
1500 - 1800	125.82	68.67	194.49
1800 - 2100	260.22	80.40	340.62
2100 - 2400	317.26	115.58	432.84
2400 - 2700	195.25	199.30	394.55
2700 - 3000	121.02	167.95	288.97
3000 - 3300	97.48	134.56	232.04
3300 - 3600	113.95	118.01	231.96
3600 - 3900	111.68	58.74	170.42
> 3900	165.74	11.10	176.84
Total	2313.77	1257.12	3570.89

* Total area of the basin is 172.12 sq. miles, 106.1 sq. miles figure excludes the mid section of the basin.

An average analysis of the coal in each of the districts was calculated and given in Table 3. As can be seen from the table, the analyses of the coals in the North Basin are slightly different from those of the South Basin. Therefore, the density figures for the different districts have been averaged out statistically, to arrive at one density figure for the North Basin and another for the South Basin coal.

To calculate the statistical averages, a weighting procedure has been used. Weights are given to the analysis figures for the different districts depending on their relative area. Thus, in case of the North Basin, the Natural Coke has been given a weight of 1, Carbon Hill 5, Midlothian 6, and, Hugenot Springs 1. These weighted averages are used to find the average values in the North and South Basin as shown in Table 3.

4.3 The Methane Resources of the Basin

As was explained earlier, the only method applicable in this case appears to be the estimation method devised by Kim. The general formula for the estimation is stated below :

$$V = \frac{(100 - \%Moisture - \%Ash)}{100} * \frac{Vw}{Vd} * [K*P^{n} - b*(1.8 *h/100 + 11)]$$

Where,

V = Volume of methane (cc/g)

K = A constant (cc/g/atm)

n = A constant

V_w = Adsorption capacity of wet coal

V_d = Adsorption capacity of dry coal

b = A constant (cc/g/deg.C)

h = Depth of the coal seam (m)

Each of the above terms will be evaluated separately, in the following sections, using the data obtained above.

The values of K and n can be calculated from the following equations:

$$K = 0.8 * (FC/VM) + 5.6$$

$$n = 0.315 - 0.01 * (FC/VM)$$

$$= 0.39 - 0.013 * K$$

Where,

FC = Fixed carbon percentage

VM = Volatile matter percentage

Applying the values of the fixed carbon and volatile matter percentages obtained in Table 3, the K and n values for the North and South Basins are calculated, as follows :

Location	K	n
North Basin	7.3457	0.2945
South Basin	7.1267	0.2973

The geothermal gradient is :

$$T = 1.8 * (h/100) + 11$$

Where,

T = Temperature (deg. C)

h = Depth (m)

11 = The ground temperature (deg.C)

However, the temperature gradient of the Richmond Coal Basin was measured by Rogers (17). He arrived at a gradient of 1 deg. F per 60 feet depth, and this gives :

$$T = 2.58 * (h/100) + 11$$

At a depth of 3000 feet the general formula gives a value of T equal to 27.46 deg. C, whereas, the result based on Roger's observations gives a value of 34.59 deg. C. Therefore, Roger's results, which are based on actual measurements in the Richmond Basin and provides a more conservative estimate of methane resources, are used in this study.

The value of the constant 'b' varies from coal seam to coal seam. It does not depend on rank. Kim's studies indicate a range for the value of 'b' from 0.11 to 0.18 with an average of 0.14. This average figure of 0.14 has been used in this study.

The pressure term is assumed to be equal to the hydrostatic head and is hence :

$$P = 0.096 * h$$

Where,

P = Pressure (atm)

h = depth (m)

However, as has been stated earlier, drill tests have shown that the pressure within the coal bed is substantially lower than hydrostatic. An average value of $P = 0.063$ atm/m with a standard deviation of ± 0.027 was determined. Since the pressure gradient of the Richmond Basin is unknown, two sets of calculations have been made, one with the hydrostatic head and another with the average figure.

Also seen in the Table 3, is the fact that the moisture and ash content of the coals in the North and South Basins are materially different. Two sets of figures for the methane content have therefore been calculated, one set for the North Basin and another for the South Basin.

4.3.1 Optimistic Estimates

Considering the terms in the equation, it is apparent that all the variables will remain more or less the same except for the pressure term whose value is not known and may vary. The maximum pressure that can occur in a coal bed is the hydrostatic head, provided there are no tectonic stresses. Thus using the hydrostatic head, the maximum methane which can be present in the basin may be calculated. For each 300 feet depth, the methane contents have been calculated in cubic centimeters per gram and cubic feet per ton for the North and South Basin coals, using this hydrostatic head as the pressure gradient. This gives the optimistic methane contents (Table 5). The corresponding coal resource figures for each of these depths are applied to the above, giving the optimistic methane resource estimates (Table 6).

4.3.2 Conservative Estimates

Using the average value of the pressure term (0.063 atm/m), a conservative methane content may be estimated. The conservative methane contents in cubic centimetres per gram and cubic feet per ton are calculated and are given in Table 5. The corresponding coal resource figures for each depth when applied to the above, gives the conservative methane resource of the Basin (Table 6).

As was seen earlier, both Heinrich and Shaler and Woodworth's studies give a coal resource of 2 billion tons. Taking the ratio of the estimated coal tonnage of 3.57 billion tons and the 2 billion tons figure, and applying it to the methane content figures already obtained, gives the methane resources based on a tonnage of 2 billion tons. Thus, on this basis the optimistic and conservative methane resources have been calculated and these are given in Table 7.

Therefore, the total methane resources in the Richmond Coal Field ranges from 723,156 million cu.ft. to 1,374,990 million cu. ft.

TABLE 5

Methane Content of the Coal in the Basin, by Depth

Depth feet	Avg. Depth m	North Basin Opt cc/g	North Basin Cons cc/g	South Basin Opt cc/g	South Basin Cons cc/g	North Basin Opt cu.ft./t	North Basin Cons cu.ft/t	South Basin Opt cu.ft./t	South Basin Cons cu.ft./t
0 - 300	45.72	5.9154	5.5623	5.8227	5.4700	189.5107	178.1995	186.5432	175.2424
300 - 600	137.16	8.3896	7.9016	8.2959	7.8069	268.7769	253.1446	265.7771	250.1095
600 - 900	228.60	9.7517	9.1845	9.6595	9.0902	312.4143	294.2439	309.4617	291.2236
900 - 1200	320.04	10.7115	10.0652	10.6209	9.9917	343.1633	323.1006	340.2620	320.1045
1200 - 1500	411.48	11.4521	10.7777	11.3629	10.6849	366.8894	345.2852	364.0342	342.3127
1500 - 1800	502.92	12.0517	11.3363	11.9636	11.2441	386.1001	363.1807	383.2847	360.2268
1800 - 2100	594.36	12.5519	11.8004	12.4650	11.7087	402.1252	378.0503	399.3423	375.1101
2100 - 2400	685.80	12.9776	12.1938	12.8915	12.1023	415.7627	390.6514	413.0063	387.7207
2400 - 2700	777.24	13.3450	12.5318	13.2596	12.4404	427.5344	401.4800	424.7986	398.5542
2700 - 3000	868.68	13.6655	12.8252	13.5806	12.7338	437.8013	410.8794	435.0811	407.9536
3000 - 3300	960.12	13.9471	13.0817	13.8626	12.9902	466.8240	419.0969	444.1150	416.1680
3300 - 3600	1051.56	14.1961	13.3071	14.1117	13.2155	454.7993	426.3196	452.0972	423.3838
3600 - 3900	1143.00	14.4170	13.5060	14.3328	13.4140	461.8784	432.6907	459.1790	429.7449
> 3900	1188.72	14.5192	13.5966	14.4340	13.5044	465.1196	435.5928	462.4204	432.6409

TABLE 6

Total Methane Resources based on Estimated Tonnage

Depth feet	Optimistic m. cu. ft.	Conservative m. cu. ft.
0 - 300	46687	43892
300 - 600	66030	62176
600 - 900	68101	64125
900 - 1200	79656	74982
1200 - 1500	59766	56230
1500 - 1800	74899	70432
1800 - 2100	136748	128535
2100 - 2400	179640	168751
2400 - 2700	168138	157821
2700 - 3000	126055	118240
3000 - 3300	103317	96853
3300 - 3600	105176	98543
3600 - 3900	78555	73566
> 3900	82222	76997
Totals	1374990	1291143

TABLE 7

Total Methane Resources based on a Coal Resource estimate of 2 billion tons

Depth feet	Optimistic m. cu. ft.	Conservative m. cu. ft.
0 - 300	26149	24583
300 - 600	36982	34824
600 - 900	38142	35916
900 - 1200	44615	41997
1200 - 1500	33474	31494
1500 - 1800	41950	39448
1800 - 2100	76591	71991
2100 - 2400	100615	94516
2400 - 2700	94173	88394
2700 - 3000	70602	66225
3000 - 3300	57867	54246
3300 - 3600	58908	55193
3600 - 3900	43998	41204
> 3900	46052	43125
Totals	770118	723156

Chapter V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The amount of methane that coal contains depends primarily on pressure, temperature, adsorptive capacity and moisture content of the coal. Permeability, porosity, degree of fracturing of the coal and adjacent rocks, and distance from the outcrop may also influence the gas content of a coal bed. The methane content of a given coal can be estimated by measuring the amount of gas liberated by a core sample recovered during drilling or by measuring gas pressure in the coal seam and then a laboratory determination of the quantity of methane held by this coal under the measured pressure. These methods, known as the direct and indirect methods,require drilling a hole, and apply only to a particular coal at a particular depth. The estimation method devised by Kim, however, gives a more general estimate and can be applied to any coal bed without undue difficulty.

The Richmond Basin may contain two to four billion tons of coal and about 700 billion cubic feet of methane may be associated with it. The methane potential which has been estimated using the estimation method, is very difficult to validate, as there is no quantitative methane data available for the basin. Also, there are no core samples on which desorption tests may be run. The data available on the basin pertaining to the depth and thickness of the coal in the basin are too sparse and consequently it was very difficult to draw contour lines for the whole basin. There were only a few geological cross sections available, but no correlation was possible between them as they were isolated and far between.

As to how much of this estimated methane is commercially recoverable, is very difficult to estimate without desorption tests on the coal itself. A rough estimate may be 50%. Even with 50% recovery, there is a substantial amount of methane available for consumption.

5.2 Recommendations

Based on the above conclusions it may be advisable to investigate the potential of the basin further. A drilling program may be undertaken around the perimeter of the basin, to delineate the actual extent of the coal. Any coal encountered during this operation must be tested for methane. A seismic survey of the area may be helpful in order to determine the continuity of the coal measures within the basin. Based on the above, deep holes may be drilled to establish the presence of coal inside the basin and the feasibility of recovering methane from it.

APPENDIX A

TABLES OF COAL THICKNESS, DENSITY AND ANALYSIS IN THE RICHMOND BASIN

Table A-1

REFERENCES TO COAL OCCURRENCES IN THE RICHMOND BASIN (22)

Reference		Mine	District	Seam Thicknesses
Grammer	(1818)	Heth's Pits	Midlothian N	50' perpendicular to dip
		At the River	Midlothian N	25'
		Between H. and River	Midlothian N	30'
		South of Heth	Midlothian S	Thins
Pierce	(1826)	?		30' - 50'
Farrand	(1833)	Ellis Hill Mine		25' coal - 14' parting - 6' coal - 2'-3' parting - 5' coal (36' coal total)
		Black Heath	Midlothian M	40' coal
		Phiney and Brown	Huguenot S	8' upper seam - 3-3/4' lower seam
Rogers	(1836)	Anderson Mine	Hugenot N	6'-16' Upper Seam - 30' Parting -4'-8' Lower Seam
		Willis and Crough		5' Upper Seam -11' Parting -4' Lower Seam (Principal seams)
		Tuckahoe Creek	Carbon Hills	Up to 5 Seams -and More Thin Ones
		River Pit	Midlothian N	20' Seam (possibly west side)
		Mill's Mine	Midlothian N	0-60' Variable (with shale partings)
		Midlothian	Midlothian M	30' or More
Rufkin	(1837)	Graham's Pit	Huguenot N	10' Seam -30'-40' Parting - Second Seam
		Wooldridge, Heth	Midlothian M	50' or More
Rogers	(1840)	?		Varies from 20' -50' aggregate thickness
Tuomey	(1842)	Coates Pit (Hall)	Clovernill N	2'
		Hills Pit (1 m.s)	Cloverhill N	5'
		Cloverhill	Clovernill	14' (including 3' partings)
Woolworth	(1842)	Maidenhead	Midlothian M	36' Average
		Thompson Blunt	Midlothian M	30' Average
		Gowrie	Midlothian M	6' Average
		Stonehenge	Midlothian S	12'-16' First, 28" Second, 54" Third - Others Below
		Midlothian	Midlothian M	36' Variable up to 50'
		Cox's Pitts	Cloverhill	7'-15'

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Table A-1 continued

Reference		Mine	District	Seam Thicknesses
Lyell	(1847)	Black Heath	Midlothian M	30'
		North of River	Carbon Hill	Two to Three Seams Almost everywhere 3 beds
		Cloverhill	Cloverhill	5 Seams
		Midlothian	Midlothian M	Coal 36' - Parting 9' - Coal 1'
		Duval's Pit	Midlothian N	3 Seams - 10' c. -35' parting - 3' Coal - Parting -6' coal - Other thin coals below
		Engine Pit	Midlothian N	30' - Below it two seams -3' and 1'
		Dover	Huguenot N	16' - Two thinner ones below
		Beaver	Clovernill	3 small seams below 4' seam - 30' parting -10'-12' coal
		Eoge-Hill	Carbon Hill	8' Coke - Below it two coal seams 4'-5' thick each
Rogers	(1854)		Carbon Hill	5' coke, ± 25' parting - thin seam coal 20' parting - coal
Taylor	(1855)	?		Two or three beds -11'-40' of coal
Daddow & Bannon	(1866)	?	South of River Carbon Hill	20'-60' of coal. Section 1 seam 50', small seam above it 6 seams 2 x 1' seams, 70' parting, 6' seam, 60' parting, 6' seam, parting, 5' seam, parting, 7' seam
		Midlothian	Midlothian M	36'
Heinrich	(1873)	Midlothian	Midlothian M	5'-6'4" coal, 6' parting, 3'-4' coal, 2" parting, 11' coal, 1" sulphur, 2'7" coal, parting, 5'7" coal, parting, 1'6" coal Up to 60' or 70' thick (with partings
McFarlane	(1873)	?	North East	North East - Two Seams total 10' -17'
		Anderson (Graham)		6'-16' -30' parting 4'-8' lower seam
		River	Midlothian N	20' seam (possibly west side)
		Hills	Clover Hill	5', 6' and 25' - Three seams
		Midlothian	Midlothian M	30'
		Maidenhead	Midlothian	25'
		Black Heath	Midlothian	40'
		Creek Pit		6' coal, 6' parting, 48' coal with 2' partings included
Coryell	(1875)		Midlothian	20' - 60' coal
			Carbon Hill	Coal Seam ? - 40'-60' parting - 6' coal -12' parting 5' coal 50' parting -6' coke

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Table A-1 continued

Reference		Mine	District	Seam Thicknesses
Henrich	(1876)	Midlothian Midlothian	Midlothian Midlothian	36' (in pump shaft at 716') 84 acres averaging 20' coal 595' West of Grove 4 Seams 14-1/2', 12' and 4-1/2-5 plus one of 1'
Henrich	(1878)	General Midlothian	 Midlothian Carbon Hill	3 coal seams 3-1/2 coal - parting -1' coal-parting-14'6" coal - large parting - 5" coal 6' coal-17' parting -4-1/2 coal -40' parting 9' coal
Fontaine	(1878)	General		2-3 important seams
Hotchkiss	(1880)	General		2 beds -one 20'-40', other 2'-5', plus 3rd Natural Coke
Jones	(1887)	Richmond C.M.+M.CO.	Carbon Hill	Top 6'-12' parting -4-1/2' coal - parting 6'-7' coal
Daddow	(1875)		Carbon Hill	5'-6' coke -60' parting -6'-8' coal -40' parting -4'-5' coal 40' parting -6'-10' coal
Raymond	(1883)	Jewett	Carbon Hill	2'+2' Carbonite -1'3" parting -1'9" Carbonite -1" parting 9' Carbonite
Bladon	(1883)	General		Eastern side 3 seams of 3'-10' thickness
Fontaine	(1885)	General Dover Cloverhill	 Carbon Hill Cloverhill	Two persistent beds-lower 4'-8' thick, next 40'-50' above, always double(ind. pan) -1'-40' thick Top two seams 6' thick each 4' coal-14' part. 12" coal-12' part-14" coal-25' part-18" coal -40 part-5' coal-5' part-15'-26' coal-40'part-4'9" coal
Newall	(1888)	Richmond CM + M CO (Trent) Breaher Shaft		6' coal-parting-4=1/2' coal-parting-6' coal 8'6" coke-9" p-8" coke-4'6" p-1'6" coal-1'7"p-4'6" coal (intp.8")-9'p-6" coal-2'6" coal -2' coal parting more coal

contd....

Table A-1 continued

Reference	Mine	District	Seam Thicknesses	
Cox (1887)	South Ann River to Appomatox River	Midlothian	4 Seams 14' thick, 10' parting, 12' thick seam, 15' parting thin seam, 30' parting, 5' seam	
Clifford(1887)	Greenhole Basin	Midlothian	2 Seams 9' thick, 2" parting, 17' thick, 4' soft black clay (This is changed to natural coke, 15 yds to the east or rise side)	
Russell (1892)	Norwood Mine	Hugenot Springs	Sandstone and shale 10' to 200', Coal with medial parting shale 5' to 7', shales 10' to 12', Coal with medial parting shale 6'	
	Old Dominion Mines	Hugenot Springs	Outcrop coal 4'6" increased to 12' down dip, 2nd was 19" 24" near surface and increased to 4' in lower part of the mine, 3rd was 4' below 2nd and coal 3' (inferior quality	
	Carbon Hill	Carbon Hill	Recent formation, soil	20'
			Alternating shales and sandstones	450'
			Cinders, so called fireclay	195'
			Nodular pyrites	15'
			Shales and sandstones	60'
			Coke seam (coke 2'4",coal 3'8")	6'
			Shale and sandstone	50'
			Coal seam	3'
			Shale, third seam	17'
			Coal	45'
			Shale and shale and sandstones, containing 6" coal seam, second seam	40'
			Coal seam, slope seam 8' to 10", first seam	9'
			Sandstone and slate to supposed granite base	160'
	Midlothian	Midlothian	Sandstone, arkose, light gray, hard, partially coarse	34'3"
			First coal seam, 3'6" coal, 1'6" slate	5'0"
			Slate and schistose sandstone, dark gray	6'2"
			Sandstone, Arkose light gray, partially schistose	4'3"
			Slate, dark gray	8'0"
			Sandstone, Arkose, gray	9'10"
			Second coal seam	1'0"
			Slate, gray	9'[illegible]

contd....

Table A-1 continued

Reference	Mine	District	Seam Thicknesses	
	Midlochian (contd.)	Midlothian	Sandstone, Arkose, gray, hard	9'0"
			Third coal seam, divided by slaty bands from 2 to 24"	12'0"
			Sandstone, gray, silicions, and gray slate	10'3"
			Fourth coal seam, divided by slaty bands	14'[illegible]"
			Slate, block and argillaceous sandstone	4'0"
	Clover Hill	Clover Hill	Coal seam local, 18" to	4'0"
			Sandstone and shale	14'0"
			Coal seam, local	0'10"
			Sandstone and shale	12'[illegible]"
			Coal seam, local	0'8"
			Sandstone and shale	40'0"
			Upper bed of main coal	5'0"
			Shale of varying thickness	5'[illegible]"
			Main coal, lower bed	13-26'0"
			Sandstone and shale	40'0"
			Lower persistent coal bed	4'9"
			Sandstone and shale, about	250'
			Gneissic floor	
Schmitz (1894)	Clover Hill	Clover Hill	I Top Seam 3' to 4.5'	
			Interval 10' to 30'	
			II Main Seam 7' to 20'	
			Interval 40' to 50'	
			III Bottom Seam (reported) 4' to 6'	
Woodworth(1900)	Gayton	Carbon Hill	4 seams, uppermost unexplored, next below 6', next 5', lowest (natural coke) 6'	
	Salle' and Burfoot tracts		3 seams upper bed 30', middle 3', lower 1' thick	
	Grove Shaft	Midlothian	3 seams, upper 14.5', middle 12', lower 3.5' to 4'	
	Manakin	Midlothian	3 seams, upper 6' to 8', middle 12', lower 3' to 4'	
Lawton (1901)	1	North of James River	4 seams top one is natural coke 8' to 10'	
			second bituminous 6' to 6-1/2'	
			third " 4'	
			fourth " 7' to 8'	

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Table A-1 continued

Reference	Mine	District	Seam Thicknesses .
D'Invilliers(1904)	Coalbrook Slope	Carbon Hill	3 seams. Upper seams C & B are separated by 12'-15' of rock. Lower seam 'A' lies 90' below 'B' vertically 'A' seam 5'1/2" with a main parting of 5-1/2" of bore and coal 'B' seam averages 4' 8" 'C' seam 3'11" including 3" band ofbone coal 10" from top Average thickness of mining coal 'A' seam 5'0" 'B' seam 3'0" 'C' seam 4'6"
	Cloverhill		Interstratified coal beds from 3'0" to 6'0" or 8'0" thick, with slate partings from 0'1" to 2'0" thick
	Grove Shaft	Midlothian	3 seams - top seam and bottom seam each 3' to 6' middle seam 7' to 12" including partings
	Dodd's Incline	Midlothian	3 seams. The two lower are 4' and 12' thick, the upper seam 14' thick.
Treadwell (1928)	Dover	Hugenot Springs	3 Seams. Top Seam 7'
	Gayton	Carbonhill	3 seams. Bottom Seam 36" to 70" (at 600' down) to 57' (700' down) B seam 37" coal, parting to c seam 60" c seam 35" coal
	Midlothian	Midlothian	Slate top 40" to 78" clean coal 12" to 30" slate 24" to 36' clean coal 18" to 20" slate 18" to 20" dirty coal Granite base
Wadleigh (1935)	James River	Northside of James River	Seam of coal, unknown 00 Rock 40' to 60' Seam of Coal 6' Rock 12" Seam of Coal 5' Rock 50' Seam of coal 6'

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Table A-1 continued

Reference	Mine	District	Seam Thicknesses	
	Midlothian	Chesterfield Co.	Coke:-	
			Thin Rock	2'6"
			Hard Shale	6'0"
			Shale, dark	1'0"
			Carbonite	2'0"
			Shale	1'0"
			Carbonite	2'8"
			Shale	1'3"
			Carbonite	1'9"
			Shale	0'1"
			Carbonite	9'0"
			Fire claybottom	
	Gayton	Carbon Hill	3 seams A,B,C	
			Section of C Seam	
			Shale	roof
			Natural coke	0-2'2"
			Coal	1-3'4"
			Carbonaceous shale	floor
			Section of B seam	
			Draw slate	roof 1'0"
			Coal, hard	
			Shale	0'1"
			Coal streaked with shale	0'6"
			Shale	0'-1/2"
			Coal, very friable	1'0"
			Shale	0'-1/2"
			Coal	0'11"
			Shale	0'1"
			Coal	1'3"
			Floor, clay thickness of bed	6'11"

contd....

Table A-1 continued

Reference	Mine	District	Seam Thicknesses	
	Midlothian	Midlothian (Chesterfield County)	Hard dark grey sandstone	3'7"
			Hard bluish grey sandstone	4'0"
			Bluish grey clay slate	2'3"
			Black slate	2'0"
			Grey argillaceous sandstone (jointed)	6'2"
			Grey slate and indurated shale	4'10"
			Top seam of coal	5-6' 4"
			Top seam of slate, often interstratified with inferior bony coal	5-6' 4"
			Clean good coal	3-4' 0"
			Dark slate	0' 1-2"
			Rich coal, highly bituminous	9.8-12' 0"
			Sulphur band	0 1-7"
			Coal	2' 7"
			Dark slate	0 1-1/2"
			Good clean coal (bottom of main seam)	5' 7"
			Light grey slate	0' 9"
			Coal	1' 6"
			Grey slate band	0' 2"
			Coal	6' 0"
			Slate (grey)	1' 6"
			Coal 5"	
			Grayslate 4"	
			Hard grey sandstone (Floor) 3"	1' 0"
	Norwood Mine	Hugenot Springs	Sandstone and shale dipping W 20 to 25	10' to 200'
			Coal, with medial partings of shale	5' to 7'
			Shales	10' to 12'
			Coal, with medial parting of shale	6'
	Powatan Mine	Hugenot Springs	5 seams, most important, locally 7'	
	Old Dominion	Hugenot Springs	3 seams, upper 4 6" increased to 12' down dip second 18 to 24" increased to 4' in lower part of mine third 4' below second -3' coal (inferior quality)	

contd....

Table A-1 continued

Reference	Mine	District	Seam Thicknesses	
	Coalbrook Slope	Carbon Hill	3 Veins of coal	
			Bottom Seam	8'
			Middle seam	3-1/2' to 4'
			Top seam	6'
Wadleigh (1935)	Carbon Hill		3 seams A,B, C.	
			Coked seam	10'
			Sand rock	30'
			'C' seam of coal & coke	4-1/2'
			Slate	6'
			'B' seam of coal	4-1/2'
			Sand rock	30'
			'A' seam	3-1/2'
	Midlothian		3 seams A, B, C	
			c Seam	40" to 72"
			Parting Slate	9" to 30"
			b Seam	24" to 40"
			Parting Slate	9" to 16"
			a Seam	18" to 24"
			Granite floor	
(Dixon)	Gayton	Carbon Hill	3 Seams A,B,C	
			c Seam	44"
			Parting Slate	72"
			b Seam	42"
			Parting Slate	60"
			a seam	50"
			Granite floor	

Table A-2

Densities of the Coal in the Richmond Basin

Date	Reference	Location	Specific Gravity	Density (lb/ft^3)
1842	Johnson	Creek Coal Co.	1.3163	82.48
			1.3228	
		Clover Hill	1.2823	80.355
			1.2887	
		Deep Run	1.4023	86.41
			1.3623	
		Crouch & Sneeds	1.4513	90.71
		Midlothian (Deep Shaft)	1.511	94.435
			1.2889	80.662
		Black Heath Pits	1.2938	80.565
			1.2839	
		Midlothian Coal Co.	1.3006	80.895
			1.2882	
		Midlothian New Shaft	1.3495	82.43
			1.3006	
		Midlothian Co.	1.2906	80.21
			1.2763	
1873	Wallace	Carbon Hill No. 2 Seam	1.219	77.600
		Carbon Hill No. 3 Seam	1.276	79.500
		Carbon Hill No. 4 Seam	1.321	82.300
		Carbon Hill	1.304	81.300
		Clover Hill	1.293	80.600
		Midlothian	1.274	76.300
		Carbon Hill Coke	1.250	77.500
1875	Wurtz		1.351	
			1.397	
			av. 1.374	
1878	Heinrich		1.292	2075 lb/yd^3
			1.246	
1923	Virginia Geological Survey	Richmond Basin	1.285	
			1.319	
			1.294	
			1.325	
			1.283	
			1.487	
			1.289	

cont'd .....

Table A-2 Continued

Date	Reference	Location	Specific Gravity	Density (lb/ft3)
1923	Virginia Geological Survey (cont'd.)		1.451	
			1.346	
			1.390	
			1.382	
			av. 1.346	
			1.362	
		Grove Shaft	1.292	
		Forbes Pit	1.318	
		Scott Pit	1.355	
		C. A. Rudd Pit	av. 1.332	
1934	Wadleigh	Natural Coke of Richmond Field	1.320	
			1.345	

Table A-3

C O A L   A N A L Y S E S (22)

1. GENERAL ANALYSES

This covers analyses given as averages for the Basin and analyses of unknown provinces.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Taylor (1840)	Unknown			1.246										
Hotchkiss (1880)	Averages			1.246 to 1.292		30 to 38.5	59 to 66	2 to 10.8	0.6 to 1.7					
Russell (1892)	Average(11)			1.436		29.632	58.113	10.903	1.232					
U.S.G.S.An.Dept. (1902)	Average	Fieldner			2.8	25.7	62.5	9.0	1.4					13490
Averages				1.305	2.8	30.91	61.40	8.18	1.23					13490

District Averages

District	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2 O_2	BTU
Natural Coke/Carbonite (1)	1.335	1.36	12.02	78.17	8.80	1.55	3.77	82.87	5.82	13080
Deep Run Basin/ (2)	1.382	1.785	23.70	65.00	9.25		4.77	82.00	5.97	
Carbon Hill (3)	1.315	1.46	26.36	63.18	9.77	1.72	4.59	73.81	1.73 5.95	13400
Midlothian (4)	1.325	1.60	31.78	56.82	9.55	1.93	4.88	76.94	8.945	13518
Clover Hill (5)	1.302	1.56	30.62	58.4	7.90	0.50				
Huguenot Springs/Mánakin (6)	-	1.95	30.10	62.90	6.43					13880
Northern Coal (1,3,4,6)	1.321	1.55	28.07	61.32	9.40	1.81				13460
Southern Coal (5)	1.302	1.56	30.62	58.4	7.90	0.50				

Contd....

Table A-3 continued

2. COKE

The 'natural coke' or 'carbonite' occurred mainly in the Carbon Hill district. However some coke was mined south of the James River, near Midlothian.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Lyell (1847)	Townes & Powell	?	?					4.70		4.23	86.54	4.53		
Taylor (1855)	Chesterfield	Rogers	1840			9.98	80.30	9.72						
	Chesterfield	Rogers	1840			16.00	70.00	14.00						
	Chesterfield	Bailey				17.00	68.00	15.00						
	Chesterfield	Clemson				10.70	83.30	6.00						
Wurtz (1875)		Wurtz	1875	1.374	0.44	14.08	77.17	8.81						
Heinrich (1878)	Carbon Hill Coke	Heinrich			1.57	9.64	79.93	8.86	Much					
	Tuckahoe	Johnson	1846	1.323	1.116	11.977	75.081	11.826	0.466					
	Carbon Hill Coke	Wallace		1.241	1.56	14.26	81.61	2.249	0.33					
Raymond (1883)	Jewett Coke	Drown	1883	1.375	2.00	15.47	79.33	3.20	4.08					
	Jewett Coke	Drown	1883	1.350	0.69	11.10	81.52	6.68	1.60					
Russell (1892)	Average Coke(11)					12.50	79.93	6.55	0.26					
Woodworth (1900)	Midlothian	Riggs	1885		1.66	18.35	67.13	12.86	4.70					
Woolfolk (1901)	Carbon Hill	Navy Dept.	1895		0.90	5.75	86.725	6.625	0.603					
(1928)	Gayton	Navy	1895		0.43	13.593	80.103	5.147	0.137					
	Gayton	Navy	1895		0.31	7.036	77.963	17.526	0.235					
USBM TP 656 (1944)	Midlothian	Cooper et al	1944		3.1	9.3	79.4	8.2	2.2	3.3	79.2	1.2	5.9	13080
Roberts (1926)	Gayton	Fieldner			2.54	16.28	70.24	10.54	1.31					
Averages				1.335	1.36	12.02	78.17	8.80	1.55	3.77	82.87	5.82		13080
Standard Deviation				.064	0.88	3.14	6.46	4.19	1.65					

Contd....

Table A-3 continued

3. DEEP RUN AND EDGE BASIN

Mines : Edge Hill, Deep Run, Duval, Ross and Curry, Towne and Powell, Burton, Locust Hill.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Johnson (1846)	Deep Run (40)	Johnson	1846	1.382	1.785	19.782	67.958	10.475						
Taylor (1855)	Deep Run	Johnson	1846			25.16	69.84	5.00						
Lyell (1847)	Deep Run							4.70		4.77	82.00	5.97		
McFarlane (1877)	Barr's #1	Rogers	1840			24.00	70.80	5.20						
	#2	Rogers	1840			22.83	54.97	22.20						
	#3	Rogers	1840			24.70	65.50	9.80						
	#4	Rogers	1840			24.33	56.07	22.60						
	Deep Run	Rogers	1840			25.16	69.86	5.00						
Averages				1.382	1.785	23.70	65.00	9.25						
Standard Deviations						1.91	6.72	6.06						

Contd....

Table A-3 continued

4. CARBON HILL

Mines:

Carbon Hill, Coalbrook, Coke Pit #1, Coke Pit #2, Gayton, Cook, H.J., Old Dominion, Dale, Eureka, Sanders, Maggie (Roberts 1929)
Coke Shaft, Coalbrookdale, Jones, Randolph, Waterloo, Woodward, Will's, (Wadleigh 1938)
Wickham's, Tuckahoe, Scotts, Cott-ell, Trents, Crouch and Sneed, James River, Richmond (Eavenson 1942)

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Johnson (1846)	Crouch & Sneed	Johnson	1846	1.451	1.785	23.959	59.976	14.289	0.427					
Taylor (1855)	Richmond	Andrews				32.00	59.25	8.75						
	Randolph's	Rogers	1840			30.50	66.15	3.35						
	Coalbrookdale	Rogers	1840			29.00	66.48	4.52						
	Crouch's Lower	Rogers	1840			30.00	64.60	5.40						
	Crouch Mean of 4	Johnson	1846			23.96	67.32	8.72						
	Scott's	Rogers	1840			33.70	60.86	5.44						
	Waterloo	Rogers	1840			26.80	55.20	18.00						
	Will's	Clemson				28.80	66.60	4.60						
Heinrich (1878)	Carbon Hill #1	Heinrich	1878		1.40	20.60	60.80	17.20						
	#2	Heinrich	1878		0.40	18.69	71.00	10.00						
Robertson (1873)	Carbon Hill #1	Wallace	1873	1.219	1.640	29.08	63.35	5.68	0.08					
	#2	Wallace	1873	1.276	1.800	21.95	68.11	7.94	10.00					
	#3	Wallace	1873	1.321	0.820	32.43	58.78	6.92	1.050					
	Outcrop	Wallace	1873	1.304	1.060	27.97	60.99	8.88	1.100					
Woolfolk (1901)	Carbon Hill #1				0.79	26.65	69.20	3.36	0.63					
	#2				9.88	26.99	66.96	5.15	1.128					
	#3				0.70	25.24	66.11	7.95	1.04					
Taylor (1926)	Scott			1.318										
Miller (1913)	Old Dominion "B"	Fieldner	1913		2.11	23.58	56.95	17.36	2.16	4.44	69.22	1.59	5.23	12200
	"C"	Fieldner	1913		2.81	25.70	62.47	9.02	1.43	4.90	76.55	1.81	6.29	13493
	Old Dominion 'B'	New River Co.	1913		.069	24.91	67.02	7.38	1.32					14393
	'C'				1.12	25.98	57.63	15.27	1.54					13042
d'Invilliers (19??)	Coalbrook C Ave(8)	McCreath			.740	25.229	59.093	13.773	1.159					
	B Ave(3)	McCreath			.716	25.368	59.549	12.780	1.585					
	A Ave(6)	McCreath			.698	22.724	55.562	20.926	2.089					
Jones (1916)	Richmond				1.34	33.45	57.05	6.16	2.000					
Wadleigh (1934)	Scotts				2.09	32.89	60.31	4.71						13920
	Scotts				1.81	32.08	59.28	6.83						13840
	Gayton #1				0.79	26.65	69.20	3.36	0.63					
	#2					26.99	65.98	5.515	1.129					
	Coalbrook	Parsons Mnf.	1910			23.70	63.67	12.63						13850
Eby & Campbell (1926)	Gayton 'C'					26.4	64.3	9.3	1.5	4.7	78.8	1.9	8.8	13880
	'C'				2.5	16.3	70.3	10.9	1.3					
						16.7	72.1	11.2	1.3					
	'B'					24.1	58.2	17.7	2.2	4.3	70.7	1.6	3.5	12460
Averages				1.315	1.46	26.36	63.18	9.77	1.72	4.59	73.81	1.73	5.95	13400
Standard Deviation				.077	0.86	4.19	4.93	4.95	1.73	.268	4.59	0.15	2.21	769

Contd....

Table A-3 continued

5. MIDLOTHIAN

Mines : Aetna, Blackheath, Boiling, Buck & Cunliffe, Burfond, Diamond Hill, Forbes, Gowrie, Greenhole, Grove, Jevett (Coke), Maidenhead, Mills & Reed, Creek, Salle (E), Stone Henge, Union, Woolridge (Taylor 1835), Blunts Thompson, Murphy, Midlothian, Railey, Nolts, Dickerson, Trabue, Billions Arsenal, James River, Stanford, Major Clarkes, Heth's, Willis Brown, English, Chesterfield.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Silliman (1842)	Midlothian			1.292		33.62	58.26	7.67						
Johnson (1846)	Midlothian 900'	Johnson	1846	1.437	1.172	27.278	61.083	10.647						
	Creek	Johnson	1846	1.319	1.450	29.678	60.300	8.572	2.890					
	Blackheath	Johnson	1846	1.289	1.896	30.676	58.794	8.634	1.937					
	Midlothian Ave	Johnson	1846	1.294	2.455	29.796	53.012	14.727	0.058					
	Tippecanoe	Johnson	1846	1.346	1.841	34.165	54.620	9.374	0.377					
	Midlothian New	Johnson	1846	1.325	0.670	33.490	55.400	9.440	2.286					
	Midlothian Screen	Johnson	1846	1.283	1.785	34.497	54.063	9.655	1.785					
	Midlothian	Johnson	1846	1.390	1.014	28.736	56.112	14.138	1.014					
Lyell (1847)	Blackheath							9.35		4.06	80.38	6.19		
Taylor (1855)	Stonehenge	Rogers	1840			36.50	58.70	4.80						
	Maidenhead	Rogers	1840			32.83	63.97	3.20						
	Heth	Rogers	1840			37.65	62.35	2.80						
	Mill's and Reid	Rogers	1840			38.60	57.80	3.60						
	Willis	Rogers	1840			32.50	62.90	4.60						
	Greenhole	Rogers	1840			31.17	67.83	2.00						
	Heth Deep Bot	Rogers	1840			35.82	53.36	10.82						
	Heth Deep Mid	Rogers	1840			28.40	66.50	5.10						
	Heth Deep Top	Rogers	1840			28.80	61.68	9.72						
Heinrich (1878)	Midlothian	Hubbard			2.00	31.62	58.26	7.67						
	Midlothian	Alexander				31.60	61.10	7.10						
Heinrich (1878)	Midlothian Grove	McCreath			1.03	38.23	54.27	6.47	1.53					
	Midlothian Ave.	McCreath			1.05	36.49	46.702	15.788	2.23					
Robertson (1873)	Midlothian			1.271	1.080	34.57	57.73	6.58	0.04					
Wortham (1916)	Midlothian	McCreath			0.636	31.368	54.899	10.635	2.549					
Taylor (1926)	Grove			1.362										
	Forbes			1.292										
Treadwell (1928)	Midlothian				1.35	32.80	59.67	6.18	1.39					14,290
	Murphy				1.12	36.58	54.66	7.84	1.07					13,984
D'Invilliers (1904)	Midlothian Dodds	McCreath	1904		.710	30.15	48.377	19.4	1.263					
	Doods	McCreath	1904		.654	34.016	49.955	11.82	3.555					
	II Lev.	McCreath	1904		1.072	29.308	49.140	18.72	1.760					
	New	McCreath	1904		.598	30.822	56.190	10.10	2.210					
	New	McCreath	1904		.700	31.150	59.273	7.25	1.627					
	II Lev.	McCreath	1904		.678	30.822	54.199	11.57	2.871					
	New	McCreath	1904		.603	32.307	51.472	18.98	2.741					
	New	McCreath	1904		.612	31.838	53.363	11.39	2.797					
	Midlothian	Carpenter			1.90	29.48	52.32	13.63	2.67					
	Midlothian	Carpenter			1.51	29.75	60.50	6.33	1.91					
	Midlothian	Carpenter			1.63	28.52	56.89	10.85	2.12					
	Midlothian	Carpenter			1.28	31.83	59.79	6.05	1.04					
	Midlothian	Carpenter			.95	29.06	55.61	12.38	2.10					
	Midlothian	Carpenter			1.18	28.95	49.08	16.00	4.59					
Jenny (1949)	Midlothian	Scott			2.7	33.4	54.3	9.6						
Eby & Campbell	Morgan Prosp	Copper et al			6.6	31.3	54.8	7.3	1.8	5.7	73.5	1.3	10.4	13,210
(1944)	Morgan Prosp	Copper et al			7.7	16.4	64.1	11.8	1.7					11.960
Averages				1.325	1.600	31.78	56.82	9.55	1.93	4.88	76.94		8.9	13,518
Standard Deviation				0.050	1.58	1.50	4.84	4.22	0.98					1,252

Contd....

Table A-3 continued

6. CLOVER HILL

Mines : Brighthope, Coxe, Clover Hill, Hall, Hill, Jaw Bone, Park Hill, Raccoon, Vaden, Retreat, Rowletts Beaver (Wadleigh 1930), Moody & Johnson's (Eavenson 1942), Rudd (Roberts 1928).

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Wooldridge (1842)	Clover Hill	Andrews		1.31		38.5	55	6.5						
Lyell (1847)	Clover Hill							9.87		5.23	76.49		8.41	
Taylor (1855)	Winterpock	Rogers	1840			29.12	65.52	5.36						
Robertson (1873)	Clover Hill			1.293	1.780	23.89	56.23	7.62	0.48					
	Coxe (4)	Johnson	1846		1.34	30.98	56.83	10.13	0.51					
Ansburner	Raccoon				1.34	32.45	57.05	7.18	1.98					
Averages				1.30	1.49	30.99	58.13	7.78	0.99					
Standard Deviation						5.30	4.20	1.88						

7. HUGUENOT SPRINGS (Western Outcrop - South of James River)

Mines : Finney, Norwood, Old Dominion, Sallis, Scott, Spencer (Wadleigh 1930), Powhatan, River Pitts (Eavenson 1942), Blayton, Kennon, Towne.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
Roberts (1929)	Powhatan	Rogers	1840			32.32	59.87	7.80						
Wadleigh (1934)	Scott				2.09	32.89	60.31	4.71						13,920
	Scott				1.81	32.08	59.28	6.83						13,840
Averages					1.95	32.43	59.82	6.45						13,880

Contd.....

Table A-3 continued

8. <u>MANAKIN</u> (Western Outcrop - North of James River)

<u>Mines :</u> Dover, Anderson & Moody, Graham, Adams (Eavenson 1942), Manakin, Aspinwall.

Reference	Mine	Analyst	Date	SG	H_2O	VM	FC	Ash	S	H_2	C	N_2	O_2	BTU
McFarlane (1877)	Anderson's	Rogers	1840			28.30	66.78	4.92						
Heinrich (1878)	Anderson's	Clemson				26.00	64.20	9.80						
Bladen (? ?)	Anderson's	Rogers	1840			29.00	66.48	4.52						
Averages						27.77	65.82	6.41						

APPENDIX B

CONTOUR MAPS OF THE RICHMOND COAL BASIN

B-1 OVERBURDEN THICKNESS CONTOURS

B-2 CUMULATIVE COAL THICKNESS CONTOURS

B-3 SUPERIMPOSED COAL AND OVERBURDEN THICKNESS CONTOURS

(SEE INSIDE BACK COVER)

APPENDIX C

AREAS AND VOLUMES UNDERLAIN BY COAL IN THE RICHMOND BASIN

Table C-1

Areas and Volumes underlain by Coal in the North Basin

Areas are in 10 million square feet

Thickness (feet) / Depth (ft)	60+	50-60	40-50	30-40	20-30	10-20	0-10	Total vol. million cu. ft.
0 - 300	-	0.0421	0.3031	2.0844	5.4929	9.8312	19.9640	4735.20
300 - 600	0.2808	0.4252	1.0338	4.8348	3.6018	4.4089	5.6449	4403.80
600 - 900	0.7509	0.5519	0.8091	2.1174	4.7944	3.6294	3.2764	3766.10
900 - 1200	1.3477	0.5657	0.8204	1.6233	2.8508	3.0324	3.1524	3382.30
1200 - 1500	0.7076	0.3837	0.6949	1.4232	2.5239	2.3082	2.0307	2525.20
1500 - 1800	0.8519	0.4645	1.4743	1.6759	2.3615	2.4576	1.5173	3051.50
1800 - 2100	3.0847	2.2133	1.6651	2.6695	3.2333	4.3037	2.1090	6311.10
2100 - 2400	2.7924	1.8823	1.6709	3.6085	6.7977	7.1059	4.0743	7694.60
2400 - 2700	1.5511	0.6905	1.4080	2.6535	3.5239	4.7731	5.3125	4735.30
2700 - 3000	1.7230	0.7353	0.8165	0.8325	1.3361	2.7991	1.6812	2935.00
3000 - 3300	1.9107	0.7512	0.8627	0.6122	0.2781	0.5734	0.9315	2364.20
3300 - 3600	3.1736	0.5488	0.7440	0.1943	0.3592	0.4127	0.0592	2763.50
3600 - 3900	2.1678	0.7955	1.4347	0.1064	0.5979	0.8746	0.1338	2708.40
> 3900	2.4717	1.2687	1.2053	1.5252	2.6025	0.6553	0.2726	4019.60
Totals	22.8140	11.3180	14.9430	25.9610	40.3540	47.1660	50.1600	

Table C-2

Areas and Volumes underlain by Coal in the South Basin

Areas are in 10 million square feet

Thickness (feet) / Depth (ft)	60+	50-60	40-50	30-40	20-30	10-20	0-10	Total vol. million cu. ft.
0 - 300	0.6616	0.1949	0.3714	0.4618	0.6807	0.7978	3.1029	1277.90
300 - 600	1.2359	0.3912	0.5037	0.4193	0.3634	0.2916	2.5997	1594.70
600 - 900	1.6711	0.2583	0.2848	0.1032	0.1760	0.5563	2.4146	1557.20
900 - 1200	1.7356	0.1791	0.2754	0.1579	0.2049	0.5869	2.1024	1563.40
1200 - 1500	1.7367	0.1288	0.2921	0.0921	0.1874	0.4228	1.3990	1457.70
1500 - 1800	2.1107	0.1458	0.2864	0.1242	0.2176	0.2971	1.4382	1689.80
1800 - 2100	2.5593	0.1820	0.2559	0.2231	0.1848	0.2581	1.2912	1978.40
2100 - 2400	4.1362	0.1513	0.1172	0.1545	0.1665	0.2968	1.7240	2844.10
2400 - 2700	6.7879	0.2272	0.3017	0.7202	0.7447	0.7963	0.2593	4904.10
2700 - 3000	5.1127	0.7630	0.5655	0.3833	0.3329	0.4679	2.0654	4132.60
3000 - 3300	4.4319	0.2805	0.2691	0.3214	0.3133	0.3517	2.6594	3311.00
3300 - 3600	4.4139	0.0745	0.0965	0.0916	0.0985	0.1017	1.9850	2903.90
3600 - 3900	1.5435	0.2769	0.4420	0.2058	0.2114	0.1587	0.3860	1445.30
> 3900	-	0.0218	0.0656	0.1723	0.2653	0.4123	0.8605	273.00
Totals	38.1370	3.2750	4.0970	3.3410	4.1470	5.6020	24.2880	

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ESTIMATION OF THE METHANE RESOURCES IN THE RICHMOND COAL BASIN, VIRGINIA

by

Amitabha Mukherjee

(ABSTRACT)

Methane, the natural byproduct of the coalification process, is held within coal beds under pressure. It is recognized that most of the methane present in coal occurs in the adsorbed state. The amount of methane present depends mainly on the pressure, temperature, adsorptive capacity and moisture content of the coal. Permeability, porosity, degree of fracturing of the coal and adjacent rocks and distance from the outcrop may also affect the methane content of a coal bed.

The methane content of coal seams can be estimated by the direct, indirect and he estimation methods. The first two methods require drilling of holes and taking samples, whereas, the third method estimates the methane content from a predetermined relationship involving the physical and chemical characteristics of coal. In this study, since no samples are to be taken and evaluation is to be based on existing data, the estimation method has been chosen to determine the methane content in the basin. The coal resources

have been estimated from the data and applied to the methane content determined, to arrive at the methane resources.

The results indicate that there may be 2 to 4 billion tons of coal in the basin and about 700 billion cubic feet of methane may be held within it.

OVERBURDEN THICKNESS CONTOURS

APPENDIX B

FIGURE B-1

+ ACTUAL MEASUREMENT POINTS (FT)

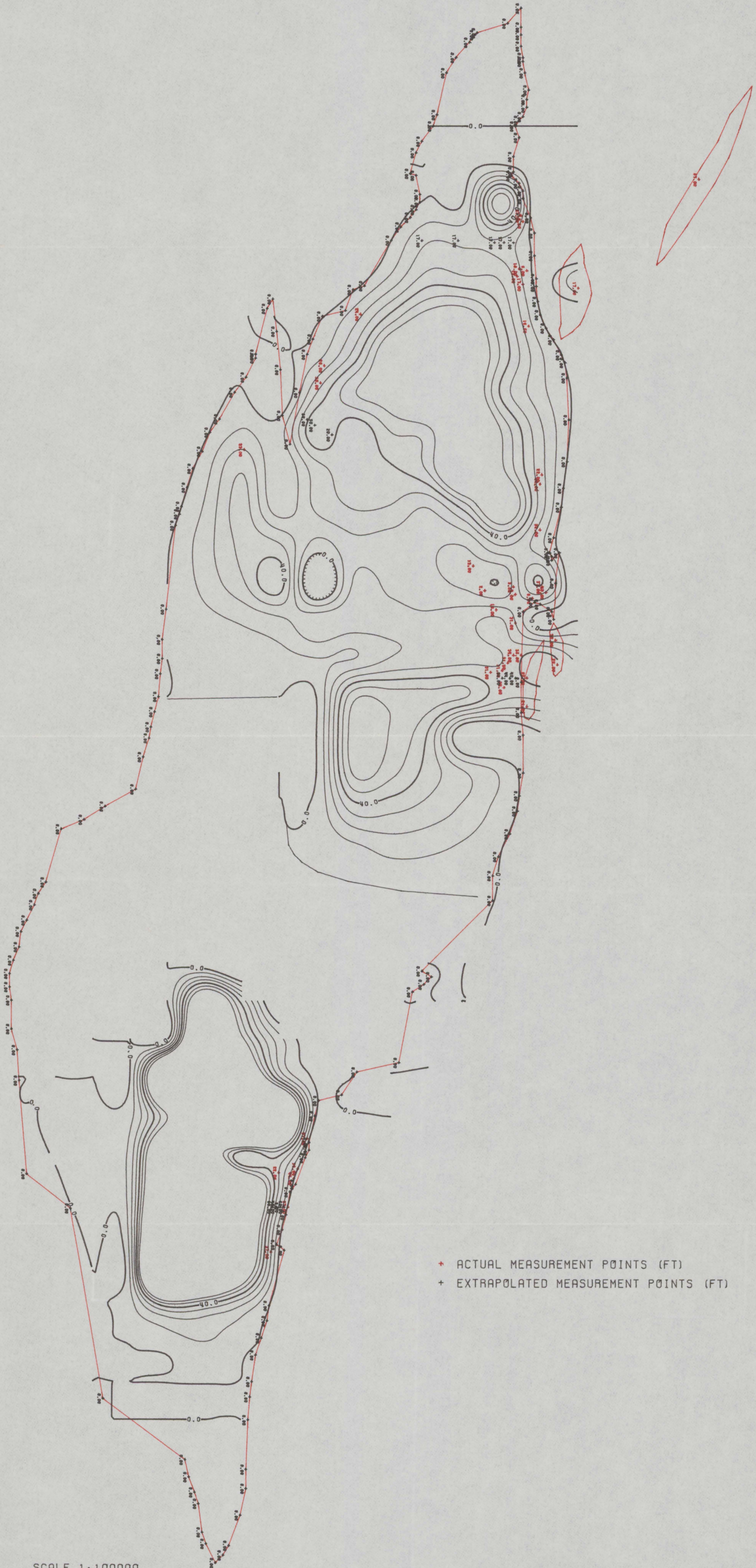
+ EXTRAPOLATED MEASUREMENT POINTS (FT)

SCALE 1:100000

CUMULATIVE COAL THICKNESS CONTOURS

APPENDIX B

FIGURE B-2



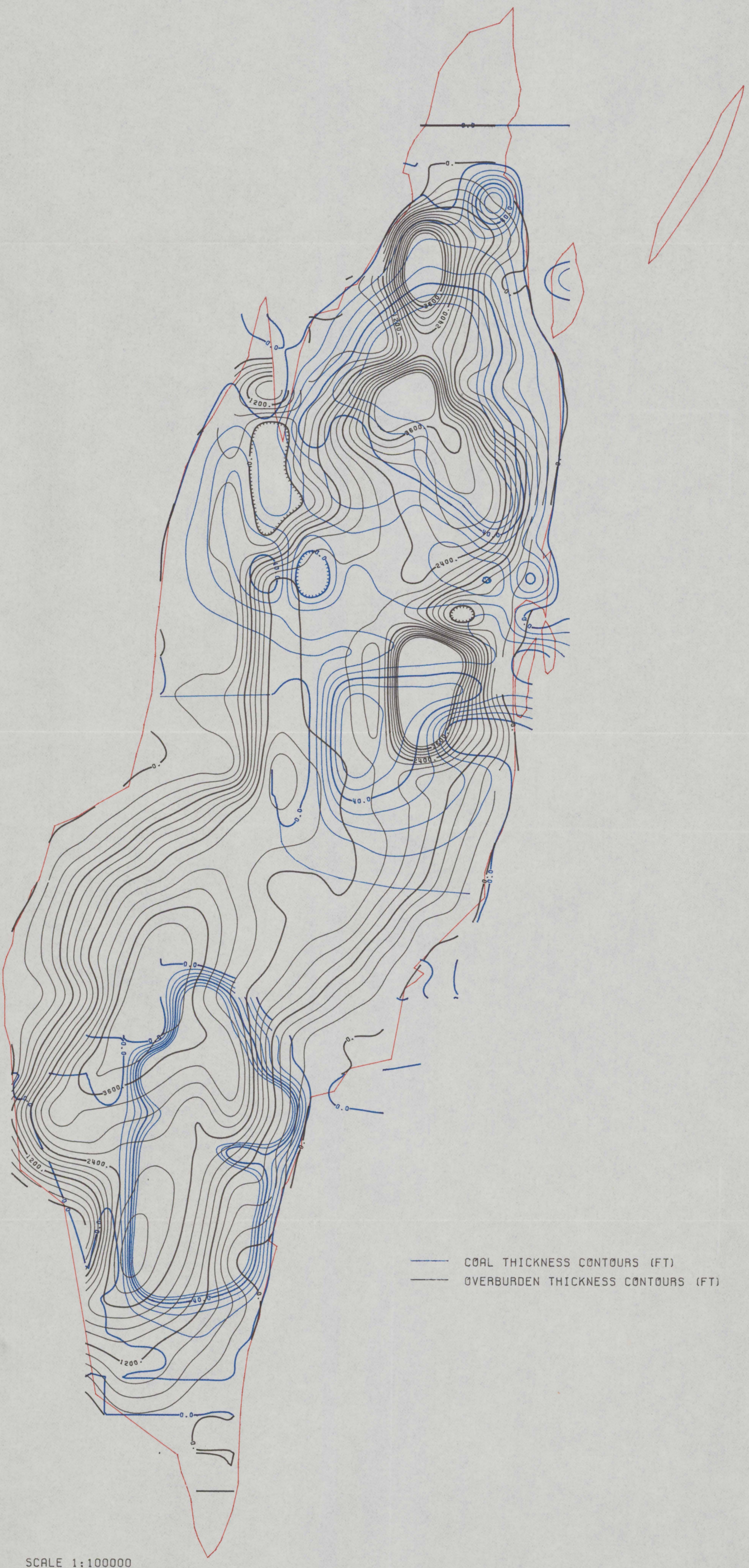
+ ACTUAL MEASUREMENT POINTS (FT)

+ EXTRAPOLATED MEASUREMENT POINTS (FT)

SCALE 1:100000

SUPERIMPOSED COAL AND OVERBURDEN
THICKNESS CONTOURS

APPENDIX B
FIGURE B-3



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