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**EVALUATION OF DATA GATHERED FROM UNMINEABLE
COAL SEAMS**

Final Report

June 1982

Work Performed Under Contract No. AC21-80MC14255

**INTERCOMP Resource Development and Engineering, Inc.
Houston, Texas**

**Technical Information Center
Office of Scientific and Technical Information
United States Department of Energy**

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FROM UNMINEABLE COAL SEAMS**

**PREPARED FOR
THE DEPARTMENT OF ENERGY
UNDER
CONTRACT NO. DE-AC21-80MC14255**

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**INTERCOMP Resource Development and Engineering, Inc.,
Houston, Texas**

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INTRODUCTION

As part of the U.S. Department of Energy's (DOE) programs directed at gas recovery from unconventional sources INTERCOMP Resource Development and Engineering, Inc. (INTERCOMP) is under contract to the Morgantown Energy Technology Center (METC) to provide for the reduction of uncertainties in critical parameters related to the methane recovery from unmineable coals in the United States. To accomplish this objective INTERCOMP has assisted in test site selection, planning, and monitoring when requested and evaluated the results of test in terms of methane production potential and economics for selected well sites, geologic settings, and geographical areas. The work described in this report was done under Contract No. DE-AC21-80MC14255 dated September 23, 1980.

This is a continuation of two earlier contracts in which an optimized test program was specified and in which the results of that program were partially implemented and evaluated. The objectives and results of these two previous contracts (EM-78-C-21-8352 and DE-AC21-79MC1064) are given in the Background section of this report so that the continuity of INTERCOMP's involvement in the Methane Recovery from Coalbeds Project, implemented by METC can be better understood by the reader. The reports resulting from these contracts are referenced.^{1,2*}

In this report INTERCOMP's effort in assisting the Bureau of Mines to understand the nature of a communication problem between the vertical dewatering hole and the three horizontal degasification legs in the Emerald Mines Horizontal Drilling Project is described. Recommendations made by INTERCOMP on how to determine the amount of communication and the answers to several other questions asked are given in the section "Assistance in Test Planning". The use of INTERCOMP's numerical simulation model³ was necessary in this effort.

The section entitled "Resource Assessment" gives the evaluation of each specific well site tested for methane production that furnished to INTERCOMP by METC.

*All references, tables, and figures are given at the end of report.

A brief description of the well location, area geology, test performed on the well, and the results of INTERCOMP's evaluation are given on each well. The economic potential of each geologic basin in which test were made is discussed. And finally, the overall results of the testing program evaluation to date is given. The results of evaluations completed in prior INTERCOMP reports to METC are combined with this current report in this discussion.

BACKGROUND

The Unmineable Coal Drilling Project, as it was called at one time, had as its objectives:

- o Obtain adequate field data for a refined estimate of methane content of unmineable U.S. coals.
- o Determine the flow rate of methane that can be produced from boreholes on a practical basis.
- o Provide the basis for gas production demonstration projects from such sites under conditions which would lead to commercialization from development.

In pursuit of these objectives, METC contracted for the service of INTERCOMP to perform the following services:

- a) Design a well testing project.
- b) Recommend specific sites for testing.
- c) Assist in the acquisition of selected sites.
- d) Assist with well testing, evaluation of test results, and production predictions.
- e) Provide available data on six coal basins: Powder River, Southeastern Uta-Piceance, Raton, San Juan, Western Queterior and Appalachia.

INTERCOMP's proprietary mathematical model of coalbed methane reservoir behavioral characteristics was to be used to predict the flow characteristics of those wells selected for flow-testing.

This first contract (EM-78-C-21-8352) was fulfilled by INTERCOMP with the preparation of the three volume report entitled "Final Report - Test Program to Determine the Feasibility of Producing Methane from Unmineable Coalbeds"¹ dated April 1979. Much of the information in this report is summarized in the Methane Recovery from Coalbeds Section of the DOE publication "Semi-Annual Report for the Unconventional Gas Recovery Program."³ The diverse nature of INTERCOMP's effort required that its report be divided into three volumes described below:

Volume I was entitled "Test Program to Determine The Feasibility of Producing Methane From Unmineable Coalbeds". This volume documented the development of a test program that attempted to scientifically outline the types and number of tests necessary to determine the feasibility of producing methane from coalbeds. A numerical simulator of the coal-methane system was discussed and utilized. Costs of the test modules were developed and utilized in conjunction with the simulator results to establish optimum test procedures.

Volume II was entitled "An Analysis of Methane Potential From Unmineable Coalbeds in Selected Areas of the United States". It documented the potential geologic basins that needed to be investigated for feasibility. It also delineated specific sites and companies that were contacted for their assistance during 1978 test activities.

Volume III was entitled "Analysis of Test Data Taken During 1978 Test Program-Methane From Coalbeds Project". This was the analysis of the data taken during the 1978 test program. The analysis looked at five test sites which included data from eight wells. The test procedures and techniques were discussed in the context of the overall test program. The results were compared with the simulator input which was used to develop the test program.

The second contract with DOE (DE-AC21-79MC10641) called for INTERCOMP to assist in the characterization of unmineable coalbeds with particular emphasis on methane producability. This assistance is to be implemented based on the following scope of work:

1. Assist in the location of well drill sites which are most favorable for resource characterization.

2. Synthesize available data and determine standard data forms and tests.
3. Assist in the preparation of test plans for selected well sites.
4. Establish the methane production potential from coal at the test well sites, in the geologic setting, and the geographical area by: (1) using test parameter data in a computer based model to determine its effect on well deliverability, (2) estimating the in-place gas, (3) estimating potential deliverability over the reservoir life, if produced.
5. Provide a relationship of the critical production parameters to the overall production economics, including gas unit prices.
6. Provide for the on-site supervision and/or monitoring the tests when required.
7. Develop an assessment of the gas producibility of the coal type and rank with respect to data parameter ranges, gas in place estimates, and well deliverability potential.

During the year of this second contract, no activities took place under scope of work items 1, 2, 5, and 7. However, three instances occurred in which assistance was requested for preparation of test plans, item 3, and four test well site analysis were performed under item 4. Only one instance occurred where INTERCOMP was called upon to provide on-site monitoring of test under item 6. The activities accomplished by INTERCOMP on these scope of work items are briefly described in the Methane Recovery from Coalbeds Section of the DOE publication "Semi-Annual Report for the Unconventional Gas Recovery Program".⁴

The main activity described in INTERCOMP's report entitled "Evaluation of Data Gathered from Unmineable Coal Seams" data August 1980 was the study of the U.S. Steel Project drilled and produced from the Mary Lee Coalbed near Oak Grove in Jefferson County, Alabama. This 17 well pattern, developed in cooperation with DOE, was producing at a combined rate of over 1 MMCFPD. Because of the abundance of data available it was designated as a specific site analysis of type III test in the Warrior Basin. As a result of the simulation of past history and future production the following conclusions were reached:

- a) Pressure interference between coal degasification wells is an important factor in gas production.
- b) Gas can be recovered from coalbeds that can materially affect the gas content of coal ahead of mining. Further, this rate is sufficient for a gas supply.
- c) If economic gas production is the purpose of coal degasification a larger well spacing is desirable.
- d) If degasification of a specific coal area for the purpose of mining is the major objective, a smaller well spacing is desirable.

A paper⁵ describing the mathematical model used in this simulation and the resulting prediction of future recovery was presented at the SPE/DOE Symposium on Unconventional Gas Recovery in May 1980.

The present contract's (DE-AC21-80MC14255) scope of work is exactly like that for the previous contract as stated above. It is a continuation of the on going study. However, during the last year there were severe cut backs in the DOE's allocation of funds for the Methane Recovery from Unmineable Coalbeds Program. No continuing study contract was awarded to INTERCOMP. This Final Report is an attempt to fulfill requirements 4, 5, and 7 in the above scope of work.

ASSISTANCE ON THE EMERALD MINE DIRECTIONAL DRILLING PROJECT

INTERCOMP was asked by DOE to assist in only one project outside of the regular evaluation of test sites during this contract. This was the DOE Project designated "Directional Drilling for Degasification of the Pittsburgh Coalbed, Green Co., Pennsylvania" under Contract No. ET-77-C-01-8891. The objective of the project was to demonstrate the capability of using directional drilling techniques to drill long, horizontal methane drainage holes in coalbeds from a surface location to reduce the explosion hazard of methane/air mixtures. The project was done in close proximity to the Emerald Mine near Waynesburg which is operated by J & L Emerald Mine Corporation. Results of the horizontal drilling phase are discussed in a paper by Diamond and Oyler.⁶

INTERCOMP was asked to investigate the data which has been collected during the drilling and production of the horizontal coalbed methane drainage hole No. 3. Recommendations were requested regarding future operations if INTERCOMP believed gas production could be improved.

INTERCOMP's Manager of Gas Projects met with DOE and J & L Emerald Mine Corporation personnel and visited the Emerald Mine horizontal drilling project site in April, 1980. The technical discussions resulted in INTERCOMP suspecting that there was some sort of completion problem in the vertical dewatering Well (EM-20). Figure 1 shows the well locations in relationship to surface features. This well did not seem to be in direct communication with the horizontal wells, as intended. As a result of this meeting, INTERCOMP was sent the data from the observation wells and the production data from the producing wells. It was hoped that this data could be analyzed to establish if present production rates were reasonable or not.

Data Analysis

The objective of the analysis of the data was to determine if Well EM-20 was or was not in good communication with the horizontal wells. To do this, it was necessary to know the natural permeability and compressibility of the coal formation and then to calculate what production rate would normally be expected if Well EM-20 was in good communication with the horizontal wells. The first step involved dealing with the

observation well pressures and the second step involved the production data from Well EM-20.

Pressure Data Analysis

The pressure data from the observation wells indicated that water was being injected into the coalbed during the drilling of the horizontal wells and causing the pressure in the general area to increase rather dramatically. At the end of horizontal drilling, the pressure fell off rapidly. Two attempts were made to determine the permeability of the coalbed without resorting the numerical modeling techniques.

The first attempt was to plot the fall off portion of the pressure curves for selected wells on a Horner type plot to determine the permeability from the slope of the line. Permeability values calculated by this method for Wells EM-23 and 24 ranged from 53 to 64 md. However, the plots did not extrapolate back to an original pressure as a Horner plot is supposed to do. Therefore, we went to another method.

The second attempt was to assume that the area around the horizontal holes represented a reservoir surrounded by a large aquifer. Instead of the aquifer feeding the reservoir as in the depletion of an oil reservoir, we assumed the reverse, that the reservoir was feeding the aquifer. Through calculation of an average reservoir pressure (from pressure data in observation wells), and assuming different reservoir permeabilities, the amount of efflux from the reservoir to the aquifer was calculated. In order to show approximately 400 BWPD injected during the drilling phase, the permeability would have had to be 260 md. One assumption made in this technique made the answer doubtful. The technique assumed a constant pressure differential around the circumference of the reservoir between the reservoir and the aquifer. This was not true in reality especially because of the mine on one side of the area.

Because of the uncertainties in these first two attempts, it was decided to simulate the observation well pressures in the area with INTERCOMP's Implicit Gas Water Model with Adsorbed Gas Option. The model was set up using a radial grid with Well EM-20 and the intersection of the horizontal wells being in the first blocks around the center of the circle (Figure 2). The horizontal wells were simulated by high permeable one degree segments radiating from the center. The mine area was simulated by a high permeability area which was drawn down to atmospheric pressure through extra

wells placed in this area. The observation wells were placed in their respective location in the grid. The total area of simulation was large enough to prevent any significant pressure depletion occurring in the outer circumference grid blocks.

The first step in the simulation was to simulate the pressure distribution in the area resulting from the mined out area only 860 feet from Well EM-20. To do this, several short runs were made varying the permeability, compressibility of the coal, and initial gas saturation, while decreasing the pressure in the mined out area to 15 psia. It was found that permeabilities of over 50 md caused too rapid a fall off to match the observation well pressures at the time drilling began. We also found that there had to be a slight gas saturation at this time also to prevent too rapid a pressure fall off. A gas saturation of less than two percent (2%) was all that was required.

Several attempts were then made to simulate the pressures measured in the observation wells during the period that the horizontal wells were being drilled and the immediate pressure fall off period at the cessation of drilling operations. It was found that the permeability of 20 md with an injection rate from the drilling of from 125 to 200 BWPD gave the best representation of the pressures during this period.

The calculated pressures (C) plotted with observed pressures (O) are shown in Figures 3 through 9. Note that the actual well numbers EM-21 through EM-27 are shown on the computer print out as Wells 11 through 17 respectively. Although these are not a perfect match, the general trend of each well is shown in the calculated pressures. To keep the computer time used to a minimum, each well was drilled completely at the beginning of the time step, but the fluid was injected simulating drilling operations over the duration of the drilling period. For this reason, we could not expect a perfect match.

Production Analysis of Well EM-20

With a permeability indication from the previous analysis of around 20 md, the model was then used to simulate the production history of Well EM-20. Because of the various activities, such as injecting water into both EM-20 and EM-19 which occurred during the period from November 15, 1979 to February 11, 1980, it was difficult to model this period. Consequently, the almost constant producing period of EM-20, occurring between February 12, 1980 to June 30, 1980, was used for comparison purposes. Figure 10 shows the production rates of gas and water during this period.

The model was set up to show the effect of having Well EM-20 in two locations. One location was very near the junction of the horizontal wells but about 13 feet away, separated by several blocks in the model with normal permeability. The other location was in between the junction of the horizontal wells with direct high permeability connection with all three horizontal wells modeled. Figure 11 shows the production results of the well not being in direct communication with the horizontal wells. This run showed the characteristic fast fall off of water rate to around 30 BWPD and a small rate of gas production of 10 to 15 Mcfd. Note that all the plots were made starting at 50 days because the computer model needed that time to adjust for the mine development in close proximity to wells.

However, when the well was placed in direct communication with the horizontal wells, as shown in Figure 12, the water production rate did not fall off and the gas production rate increased rapidly to over 100 Mcfd. This shows the effect that the horizontal wells should have had on the gas production rate by pulling the pressure down in a large area. If the initial water production rate could be higher, as shown in Figure 13, an even more dramatic gas production rate would be expected.

Conclusions From Analysis

Based on the foregoing analysis, the following three conclusions were evident:

1. The system was capable of producing several hundred of barrels of water per day.
2. The dewatering well was not in direct communication with the horizontal wells.
3. If direct communication between the dewatering well and the horizontal wells could be established and a higher water production rate capability installed, a much higher gas production rate would be expected.

Recommendations

Based on the foregoing analysis and our understanding of the field conditions as they existed the following remedial recommendations and alternatives were submitted:

Alternative No. 1 Recomplete EM-20

- Step 1. Run gamma ray with collar locator in EM-20 to see if we can locate present slots in casing.
- Step 2. If not sure of present slot locations, run a casing inspection log to locate slots.
- Step 3. Reslot with large diameter abrasive jet.
- Step 4. Test for communication between EM-20 and EM-19 while service company still on site.
- Step 5. Hydraulically fracture with large volume of water and nitrogen if necessary. (Fracturing rates and volumes to be designed later).
- Step 6. Set existing submersible pump and produce, if possible.

Alternative No. 2 Clean Out EM-19

- Step 1. Fish out existing pump shroud and 30 feet of 1-1/2 inch PVC pipe left in hole EM-19.
- Step 2. Clean out bore hole to depth of 1640 feet.
- Step 3. Run 50 to 60 feet of 4 inch O.D. plastic pipe from 1590 to T.D.
- Step 4. Pump into well to establish communications with horizontal wells.
- Step 5. Run submersible pump and test well.

Alternative No. 3 Complete EM-21

- Step 1. Abrasive jet Pittsburgh coal seam in EM-21.
- Step 2. Inject water into well to see if communications can be established with horizontal well.
- Step 3. If necessary, fracture with water using high injection rate.
- Step 4. Run submersible pump and test.

Alternative No. 4

Complete all observation wells as producing wells and produce as a pattern degasification project. As gas saturation in coal increases the benefit of the horizontal wells within the pattern should become apparent.

Further Analysis

At a meeting in Morgantown, West Virginia on December 2, 1980 representatives of DOE, TRW, BOM and INTERCOMP met to discuss the current situation and recommendations for the future of the Emerald Mines Horizontal Drilling Project. At the meeting the analysis and recommendations of INTERCOMP given above were discussed. Additional information was requested of INTERCOMP which is discussed below.

EM-20 Production Prediction

One question asked was how much longer at the present producing rate of EM-20 would be required before the gas rate would start increasing? We ran the model with just Well EM-20 producing to January 1, 1982. The results showed no noticeable gas production increase as shown below.

<u>Model Time (Days)</u>	<u>Equivalent Date</u>	<u>Gas Production Rate (Mcf/d)</u>	<u>Water Production Rate BWP/D</u>
321	11/8/80	17.5	25.9
739	01/1/82	18.3	21.7

It appears from looking at the pressures and gas saturation around the well, that the well could produce for several more years without a dramatic gas increase, if there ever is one. It seems to be acting like a well in infinite reservoir as INTERCOMP explained at the meeting. The peak which is usually seen soon after production begins, has been negated because of gas production from the mine nearby.

Connection of Horizontal Holes

The other questions were concerning the possibility that the three horizontal holes were not connected. At the meeting, we discussed the possibility that there might be a noticeable difference in the pressures at some of the observation wells when EM-21 was produced, depending on whether H-1 was connected to the other horizontal wells or not. To investigate this, a run was made with the three horizontal wells connected and another run was made with H-1 connected to the other wells with only the normal matrix permeability of 20 md. Well EM-21 was placed in a one degree width block

next to the one degree width horizontal hole. This means that the vertical well, EM-21, was approximately eight feet from the horizontal well. Well EM-21 was produced for one week beginning on January 15, 1981 by our time scale. The production and pressure differences recorded in the two runs are shown in Table 1. The time of 389 days corresponds to the beginning of production of EM-21 and the model runs were continued for 30 days after production ceased. EM-21 was left producing through this time period.

These runs resulted in considerable gas production from EM-21 no matter what the situation. It should be noted that a change in the gas rate of EM-20 is shown even though EM-20 is not connected to the horizontal well system.

To tell if H-1 is connected or not to the other horizontal wells, it was hoped that the pressure fall offs in the observation wells would give us a clue. The pressure drops are shown in the Table 1. It can be seen that the pressure fall offs are roughly the same for the observation wells which are in the interior of the horizontal wells. For the observation wells on the outside, the fall off is only 2 to 3 psi for the not connected case where as they are from 7 to 11 psi for the connected case.

Swabbling Test of EM-24 Analysis

In order to verify the previous model results we modeled a short swabbling test run on EM-24 during March, 1980. This was designed to see if the proper Well Index was being used in the model for Well EM-21 in the previous simulation because at the time it as run we had no indication of what the Well Index should be. The producing schedule of EM-24 was given INTERCOMP but not the amount of gas or water produced during the test.

The schedule given INTERCOMP for the EM-24 test with the equivalent computer times is shown below.

<u>Event</u>	<u>Date</u>	<u>Time</u>	<u>Simulation Time</u>
Start Swabbling	March 17	11:00 A.M.	84.4583
End Swabbling		4:00 P.M.	84.6667
Start Swabbling	March 13	8:00 A.M.	85.3333
End Swabbling		4:00 P.M.	85.6667
Start Swabbling	March 19	8:00 A.M.	86.3333
End Swabbling		Noon	86.5
2 Weeks Later	April	Midnight	101.0

Exactly the same model as had been run in the previous simulation study of producing EM-21 was used except that the Well Index of Well EM-24 was varied. The Well H-1 connected case was used because at this earlier time it was thought that they might still be connected.

Tables No. 2, 3, and 4 show the results of using a Well Index of 2, 0.5, and 0.1 respectively. The production from Well EM-20 is shown on these tables because a little kick in water rate production is noticed in the simulation similar to what was actually obtained. The pressure drop for Wells EM-26 and EM-27 were not shown because they did not change over one psi. They stayed at 260 psi. For Well EM-24 not only the water and block pressure are shown, but the bottom hole pressure (BHP), the total production, and the total pressure drop as well.

The main differences in the results of the three runs with different Well Indexes are the amount of draw down in EM-24 and the volume of gas and water produced. The case with a Well Index of 2 predicts considerable production and substantial fall off in reservoir pressure near the well bore. However, the Well Index of 0.1 case produces no gas, a small amount of water and the pressure returns to the normal fall off rate (see no production data, Table 4) after two weeks.

INTERCOMP suspected that the actual production was closer to the case where a Well Index of 0.1 was used. One reason for this was that the BOM indicated that the well was pumped off during the swabbing test. Even swabbing at a rate of 300 to 350 BWPD in the case where the Well Index was 2 did not swab the well dry. This is indicated by the higher than 15 psi bottom hole pressures. The other reason we suspected a Well Index of 0.1 was correct was because of the pressure drops in surrounding wells. Comparing the simulated pressure drops to the field measured pressure drop show a close correlation as seen below.

Well Index of 0.1

Well No.	Model Press. Drop (psi)	Field Press. Drop (psi)
EM-21	2	1.25
EM-22	0	0.99
EM-23	1	1.51
EM-24	1	1.87
EM-25	7	4.96
EM-26	0	0.24
EM-27	0	0.28

Upon discussing the results of these simulations with the BOM personnel it was found that the Well Index of 0.1 case simulations did show water and gas production rates very similar to those actually produced.

Rerun of EM-21 Production Test Simulation

Because of the results of the analysis of the EM-24 swabbing test the original simulation of the planned EM-21 test were rerun using a Well Index of 0.2 instead of 2.0. The value of 0.2 in Well EM-21 was used because the block size of this well was smaller than the block size of EM-24.

The main purposes of these simulations was to determine the pressure drop in the surrounding wells when EM-21 was produced for a week and to determine if the magnitude of this pressure drop would indicate whether the horizontal Well H-1 was connected to the other horizontal wells or not. We first ran the situation where EM-21 was only produced for 8 hours a day as BOM personnel indicated this was the normal procedure. These results are shown in Table 5 for the connected and not connected case. As can be seen by inspection of the pressure drops shown in this table there is not a significant difference between the connected and not connected case. In fact we had to read the pressures at the beginning and ending production period off of the pressure maps to the nearest one hundredth of psi to tell any difference between them.

Just for comparison we restarted the two cases at 389.3333 days but let EM-21 produce for 24 hours a day for the 7 days. As you can see in Table 6, EM-21 produced approximately three times as much fluid. This increased the pressure drops and did indicate a larger difference between the connected and not connected cases at the model time of 396.3333 days. However, a difference of only 3 psi between the two cases in Well EM-23 would not be very much on which to make a positive determination of connection.

Recommendations for EM-21 Test

The forgoing analysis indicates that the pressure draw down for a 7 day swabbing test only swabbing for 8 hours per day would be inadequate to tell whether the horizontal wells were connected or not connected. Consequently the following recommendations are made;

- 1) A pumping jack with an engine which runs on propane be secured and placed on the well.
- 2) The test be of longer duration than one week, possibly 4 to 8 weeks.
- 3) Simulations run after or during the test should be able to determine whether H-1 is connected or not connected to other horizontal wells.

RESOURCE ASSESSMENT

Over a period of about three years INTERCOMP has received 40 Well Test Packages covering 10 Basins in the United States. INTERCOMP objective was to evaluate these well test in terms of gas resource available from these coals and estimate the production potential of the wells. Table 7 shows the basin, the well site designation, the total footage cored, the total thickness of coal, the number of desorption samples taken and the range of gas content found. Because these well test were evaluated at different times Table 7 also indicates the report in which the evaluation appears. The well test of coal content were usually obtained by contacting companies that were planning to drill a well to recover hydrocarbon and contracting with them to allow DOE representatives to perform coring and sampling operations during their drilling operations.

The data obtained on most test sites were incomplete for the purpose of estimating the production potential. On most wells, as can be seen in Table 7 the following data are available:

- o Coal bed thickness
- o Depth of coalbed
- o Gas content of coal, and
- o Type of coal

However, to use INTERCOMP's simulator¹ to obtain estimated production other data is needed as listed below:

- o Permeability
- o Pressure
- o Relative Permeability
- o Fracture Length
- o Fracture Conductivity
- o Sorbtion Parameter
- o Porosity
- o Gas Composition
- o Water Characteristics

- o Capillary Pressure
- o Reservoir Size and Geometry

While all these parameters are important, it was decided early in the project that all were not needed to secure a predictive level of confidence in estimating the potential deliverability of producing methane from a specific site.

The list was reduced to six important variables by leaving the other variables constant during the evaluation. These six variables are:

- o Gas Content
- o Permeability
- o Relative Permeability
- o Fracture Length, and
- o Fracture Permeability.

These six independent variables were estimated if not given in the Well Test Package.

On a form supplied with each evaluation done by INTERCOMP in this report are given the values used in these estimates. A blank form is shown in Table 8. The headings at the top of the form are self explanatory. The coal seam data portion of the form is taken from the data supplied in the well test packages. The gas-in-place box was calculated by using the total width of the coal times the weighted average gas content times a factor that converts to Bscf/section. The section is a square mile of land area.

The Production Potential, ϕ , Analysis part of the form shows the six dependent variables used in the estimation of the Production deliverability parameter ϕ . This value ϕ , called Phi, is defined as the cumulative production at the end of ten years discounted at the rate of 15 percent per year. This allows a single value to characterize the results of the simulator and is discussed more fully in the April 1979 report.¹ The same range of values for the six independent variables were used in this report as were used in April 1979 report unless they were given as data or could be calculated with the given data.

The fracture length, fracture conductivity, and permeability values were shown on the form as estimated. The pressure, if not given, was estimated using a pressure gradient with depth of .434 psi/ft. unless a regional gradient could be estimated. Input into the K_{rg} curve (No.) column is the number given to the relative permeability and capillary pressure data entered into the simulator. The three curves used are designated as follows:

Curve No. 1	Maximum gas flow curve.
Curve No. 2	Medium gas flow curve.
Curve No. 3	Minimum gas flow curve.

These three relative permeability curves are the same curves presented in Figure 6 of the April 1979 report. The adsorption Isotherm was determined by plotting the weighted average gas content versus the pressure on Figure 4 of the April 1979 report. Then a curve was drawn back to the origin using the existing curves as guides. Instead of using a curve number in this column, we entered the weighted average gas content to be used.

For economy reasons each simulation run is based on only one-quarter (1/4) of the full circular area around the well. We have also assumed 10 feet of coal in each simulation. So, the calculated value of ϕ that is placed under the column for ϕ represents only 1/4 of the production potential for a 10 ft. thick coal bed. To obtain an actual value for gas produced you would have to multiply the value by four and then multiply by one-tenth (1/10) of the total thickness of the coal. It must be remembered also, that in the plot of gas rate versus time, as shown in many figures of this report, these are only 1/4 of the rates you would expect from a 10 foot section of the coal.

Northern Appalachian Basin

Three well sites were tested in this basin which are shown in Figure 14. These sites are all found in Pennsylvania and thus are in the northern part of the basin. Coals in this basin are found in Permian Dunkard Group rocks. Total coal thickness varies from 20 to 60 feet but individual seams are usually thin. Gas emission data exist for mines in at least 15 different seams. Most of the coal is covered by less than 3,000 feet of overburden.

Test Site AAA

A report was given on the testing of the two Kinlock Development Corporation's Wells, No. 1 Stoner and No. 1 Murdock, in Green County, Pennsylvania in the August 1980 Final Report to DOE.² Gas contents were obtained on a total of 7 samples from both wells. However, although the gas content of the 34 feet of coal in the No. 1 Stoner well was given, the gas deliverability was not estimated. The weighted average gas content was calculated to be 9.22 cc/g. The pressure of one coal formation was tested and determined to be 424 psia. Injection tests before hydraulic fracturing resulted in a permeability estimate of from .5 to 1.0 md. The hydraulic fracturing attempt was not fully completed because of the exceptional high frac pressures required. Therefore in assuming a range of fracture lengths the 200 and 500 feet lengths were used. For the maximum case the maximum relative permeability curve was used. For the other cases we estimated the middle range curves.

Assuming these values as shown in Table 9 the simulated production rates from the three cases are shown in Figure 15. The most likely case gives an estimated gas deliverability, ϕ , of 11,627.

Test Site AAB

Waynesburg College in Green County, Pennsylvania drilled two core holes on the college campus between October 23rd and December 19th, 1979. A production well has been drilled, completed and put on production. However, no data on production is available at this time. This evaluation is based on the data gathered from the two core holes only.

Location and Geology

Waynesburg College is located just north of Waynesburg, Pennsylvania in the Southwest corner of the state. The two core holes were drilled on the Thayer Hall Tract.

Nine coal seams were encountered while coring to a total depth of 1439 ft. from a surface elevation of 946.5 ft. These coal seams include the Waynesburg, Sewickley, Pittsburgh, Bakerstown, Upper Freeport, Upper, Middle, and Lower Kittannings, and the Clarion - Brookville. The depth and thickness of these coal seams are given in Table 10.

Test and Results

Both holes were cored from below the casing to total depth with a Longyear-Hoffman wireline NQ (1 7/8" diameter) system having a core barrel of 10 ft. The second core hole was necessary because the drill string stuck at 956 feet in core hole 1 and had to be cut off. Attempts to deviate the hole failed, so it was necessary to twin the hole about 30 ft. to the north.

The cores were inspection logged but geophysical logs were run on the production well. Logs ran include a Dual Induction - SFL, a Compensated Neutron - Formation Density, a Borehole Compensated Sonic, and a computer generated Coal Log.

Coal samples were taken for gas desorption testing, roof or floor rock mechanical property analysis and coal quality analysis. The results of the desorption test and type of coal calculated from the coal quality analysis are shown in Table 10.

Gas-In-Place and Deliverability Estimates

Using the lithologic log thickness of each coal seam, the total thickness of coal is 40.9 feet. This combined with the weighted average gas content of 4.02 cc/g gives a gas-in-place of 6.2 Bscf/section.

In calculating the discounted gas production, ϕ , the assumed factors for the maximum likely, most likely and minimum likely cases are shown at the bottom of Table 10. The reasons for selecting the various parameters used are given below:

Fracturing - There are some 12 coal seams over an interval of 1260 ft. The thickest seam being the 6.3 ft. thick Pittsburgh Main Bench. This seam has a fairly high gas content of 4.9 cc/g but is not the highest in gas content.

The Upper Kittanning has an average of 5.5 cc/g. In completing a production well it would be recommended that at least the thicker zones be fractured. These would be the Waynesburg, the Pittsburgh and the Middle Kittanning seams. These three seams total (6.0 + 12.5 + 7.0) 25.5 ft. which is over one half of the total coal thickness. Each of these three seams are several hundred feet apart and would have to be fractured separately. Therefore, for the maximum likely case we assumed a small fracture

length with a high conductivity and for the minimum likely case we assumed no fracture. The most likely case was assumed to be a shorter fracture than the maximum likely case.

Permeability - No indication of permeability is given in the data on this well test. However, previous modeling experience for the Pittsburgh coal seam has shown that a permeability of 20 md has given good prediction results.

Pressure - Because of the large range in depths of the coal seam an average depth was used with a normal gradient. A pressure of 360 psia was used.

Relative Permeability - From previous modeling experience in coal seams the relative permeability curve usually looks more like the minimum curve presented in Figure 6 of the Preliminary Test Program.¹ This minimum curve, designated curve No. 3, was used for the minimum and most likely case with curve No. 2 being used for the maximum case.

Adsorption Isotherm - Because gas content test were made on adsorption isotherm was constructed to pass through the average gas content of 4.02 cc/g at the average pressure of 24.5 atmospheres. The shape of the curve was made similar to the shape of the medium curve shown in Figure 4 of the Preliminary Test Program.¹ This same curve was used for all three cases and is shown in Figure 16.

The results of using these parameters is shown in Table 10 as 9 ϕ of 12,568 Mcf for the Most Likely Case. Values of 72,142 Mcf and 3,185 Mcf were computed for the maximum and minimum likely cases respectively. The production rates for the first 10 years are shown in Figure 17 for all three cases.

Comments

It should be noted that the ϕ values given are by definition only for one quarter of actual discounted gas production and only for a thickness of 10 ft. Therefore actual discounted production would need to be multiplied by four and also 1/10 the actual effective thickness. For the most likely case this would give a total production discounted by 15% over the 10 year period of approximately 128 MMcf when using a thickness of 25.5 ft. Therefore, the possibility of a successful producing well at Waynesburg College looks good.

Test Site AAC

The Rochester and Pittsburgh Coal Company completely cored the Cooperative Well DDH 2355 located in Indiana County, Pennsylvania. The major coals in this county are found in the Allegheny Group of Pennsylvania age. The thick coalbeds of the Allegheny Group include the Lower, Middle, and Uppper Kittanning beds in addition to the Lower and Upper Freeport. In this well 55 feet of the Upper Freeport, Upper and Lower Kittanning were analyzed. Four samples were anlayzed for gas content but one of these samples was in shale and the canister leaked in the other sample. No other test were made on the well except that a Gamma Ray Neutron and a 3-D Velocity log were run.

Table 11 shows values assumed for the production potential simulation. The resulting gas rates are shown plotted in Figure 18. The most likely case gives a predicted value for ϕ of 10,099. Gas content is 3.6 Bscf/section. Prospects for economical methane recovery from coal in this area are good.

Warrior Basin

Only one test site package was received in this basin. The target area and location of Site CAA are shown in Figure 19. Coal in this basin is found in the Pottsville group of Pennsylvanian age. There are approximately 25 mineable coal seams with total thickness ranging from 15 to 50 feet. However, the thickest coal is only about 7 feet thick. The Mary Lee coal seam is extremely gassy in the eastern part of the basin. Multiwell degasification projects in the Mary Lee exist in Tuscaloosa and Jefferson Counties. The 17 well pattern near Oak Grove, Jefferson County, was studied by INTERCOMP and reported in the August, 1980 report.

Test Site CAA

The Grace Petroleum Corporation Well No. 1 Grimsley 35-15 designated test site CAA is located about 10 miles northeast of Fayette, Alabama in Fayette County. It is near the Davis Chapel (gas) Field. There are many coal mines in the county. In this county 5 of the 7 major coal groups that crop out in the Warrior Basin are represented either on the surface or in the subsurface.

Coring was done with a rubber sleeve core barrel but several of the coal zones were missed because of a fault in the area. The data used for depth and thickness were taken from a Compensated Neutron - Formation Density log. Total coal was found to be 18.5 feet.

Fracture Length - As shown in Table 12 these coal seam are thin and separated by at least 40 ft. It would be difficult to fracture them together; they would have to be fractured separately. A 2 to 3 ft. zone can not be fracture very deep without fracturing outside the zone. It would probably be best to cut the pipe by hydrojetting over the coal seams. Perhaps one might get up to a 200 ft. fracture with a conductivity of 150, 1000 md-in. One would probably not fracture most seams.

Permeability - We have selected an inbetween range because the coals are divided between B bituminous and A bituminous types. Some are soft, fariable coals and some are hard, blocky coals.

Relative Permeability - We selected relative permeabilty curve No. 2 for each case based on previous experience in the Warrior Basin.²

Pressure - Since these coals are spred apart we chose to use two different pressures. For the most likely and maximum likely cases the average of 5 deepest depths was used. For the minimum likely case the average of the five shollowest coal seams was used.

The predicted rates for the three cases are shown in Figure 20. Only the maximum likely case shows significant gas production. Without hydraulic fracturing the coal seams, there is little chance for successful production. Calculations show 1.4 Bscf/section of gas-in-place. If several of the coal seams could be fractured the estimated maximum likely case ϕ of 13,771 shows some promise for this area of the Warrior Basin.

Illinois Basin

(Evaluation analysis to be similar to those above, to be supplied)

See Figure 21, Table 13, 14, & 15.

Arkoma Basin

(Evaluation analysis to be similar to those above, to be supplied)

See Figure 22.

Piceance Basin

(Evaluation analysis to be similar to those above, to be supplied)

See Figure 23-25 and Tables 16, & 17.

Green River Basin

(Evaluation analysis to be similar to those above, to be supplied)

See Figure 26.

San Juan Basin

(Evaluation analysis to be similar to the those above, to be supplied)

See Figures 27-32 and Tables 18-22.

Powder River Basin

(Evaluation analysis to be similar to those above, to be supplied)

See Figure 33.

Tono Basin

The Tono Basin is located in the Western Washington Coal Region as shown in Figure 34. Only one Test Site Package was recieved from this area.

Test Site LAA

Test Site LAA is located in the Tono Basin, Washington. The Well DOE 7 was cored from 403 to 638 feet and is located in Sec. 21, T 15 N, R1W in Thurston County, Washington. DOE was invited to collect core samples for gas content analysis.

Geology

This well cored the Big Dirty coalbed which is one of the two beds known to occur for some distance in thickness greater than 10 ft. The other coalbed is the Tono No. 1 which was not cored in this well. The Tono Basin is a small structural basin within the Centralia-Chehalis Coal District. The Centralia-Chehalis Coal District is the largest subbituminous coal field in the state of Washington and is located in Thurston and Lewis Counties midway between Seattle and Portland, Oregon. At least 12 major coalbeds have been mined in this district. These beds are in the Eocene Skookumchuck and Northcraft Formation.

Gas-In-Place and Deliverability

No test were run on this site. The coring located the Big Dirty Coalbed from 602.6 to 624.3 feet for a gross thickness of 21.7 feet and a net thickness of 16.9 feet. Four coal samples for gas analysis were taken. The results from the gas analysis are shown in Table 23.

It might be possible to fracture this coal seam so we have assumed a small fracutre in the Maximum likely case. Assuming a geopressure gradient of .35 psi/ft and relatively low permeabilities the estimated deliverability parameter ϕ for the maximum case was calculated to be only 4,552. Therefore the minimum case was not calculated. The gas in place in the Big Dirty sand is estimated at 1.4 Bcf per section. The estimated production rate for the maximum likely case is shown in Figure 35.

Comments

The subbituminous coals do not usually contain as much gas as the Volatile Bituminous Coals. However, because this coal had one sample that had almost 3 cc/g gas content it was evaluated. Further sampling of the other major coal seam in this area should be done.

Wind River Basin

(Evaluation analysis to be similar to the those above, to be supplied)

GENERAL DISCUSSION OF TEST SITES

The value of the production potential ϕ can be related to overall production economics through the fact that it represents one quarter (1/4) of the cumulative production from a 10 ft coal seam over a 10 year life discounted at 15 percent. The discounted revenue that would be received over this 10 year period could be calculated as follows:

$$R_d = \phi \times 4 \times RI \times P \times h/10$$

Where:

- R_d = Revenue discounted at 15 percent per year, \$
- ϕ = Production Potential, Mscf
- RI = Revenue Interest, fraction
- P = Price of Gas, \$/Mscf
- h = Total thickness of producing coal, ft.

The 4 in the above equation is used because ϕ is calculated in the simulator for only one-quarter (1/4) of the radial area around the well. The 10 is divided into the thickness because the simulator calculates ϕ for 10 ft. For example if the coal producing interval was actually 5 ft instead of 10, the discounted cumulative production would be only .5 of ϕ .

The cost associated with producing a coal degasification well is very similar to any other gas well and falls into two major categories, the drilling and completion cost and the operating cost. The drilling and completion costs are normally associated with the depth to which one must drill. Thus these cost are frequently calculated by:

$$C_D = D \times C_F$$

Where:

$$\begin{aligned} C_D &= \text{Drilling and Completion Costs, \$} \\ D &= \text{Depth, ft.} \\ C_F &= \text{Cost per foot of depth drilled, \$/ft} \end{aligned}$$

The operating cost are frequently estimated by assuming they are a percentage of the revenue producing stream or could be estimated as a direct percentage of the revenue. If we assume that the discounting of the revenue (R_d) will not affect the calculation significantly we can calculate the operation cost as follows:

$$C_o = F \times R_d$$

Where:

$$\begin{aligned} C_o &= \text{Total Operating Cost for 10 yrs, \$} \\ F &= \text{Operating cost as a fraction of revenue, fraction} \end{aligned}$$

Combining these equations and setting Revenue equal to cost will give us the break even equation between a profitable investment or one which is not profitable. Thus:

$$R_d = C_D + C_o$$

By assuming values for some of these variables it can be seen how the value of ϕ relates to the other variables. If we assume the following values:

$$\begin{aligned} RI &= .875 \text{ (normal } 1/8 \text{ royalty)} \\ P &= \$6.00/\text{Mscf (Special unconventional gas price)} \\ h &= 10 \text{ ft. (Used in the simulator)} \\ C_p &= \$41.00/\text{ft (Normal for 0 to 2000 ft. well)} \end{aligned}$$

$$F = .15 \text{ or } 15\% \text{ (Normal for gas wells)}$$

Then the overall equation for profitability becomes:

$$\phi = D \times 2.29$$

Which relates the value of ϕ to Depth of the well to be drilled. This relationship is shown graphically in Figure 36. If a value of (D, ϕ) plotted on this chart falls above the line then the drilling and producing of this coal bed would be profitable. If it falls below the line it would not be profitable.

The two coal parameters that relate directly to ϕ are the depth and the thickness. Thus, Figure 37 is drawn from the relationship:

$$\phi = \frac{D}{h} \times 22.97$$

and shows that ϕ must be larger than 22.97 times the D/h ratio to be profitable under the assumed conditions.

Table 24 shows the gas-in-place, the type of coal, the total depth to bottom of the last coal seam encountered, the total coal thickness, the D/h ratios and the ϕ values for the maximum likely, most likely, and minimum likely cases run in the simulator on each well test site for which information has been calculated. The letter indicating the basin designation is shown plotted on ϕ versus D/h grid in Figure 38. A break even line is drawn on the same figure using the relationship $\phi = D/h \times 22.79$. Those letters falling above the breakeven line are indicated as being profitable for development. Those well sites falling below the breakeven line are indicated as not being profitable to develop. The ϕ values used are for the most likely case.

CONCLUSIONS

1. Forty well test sites were evaluated. The simulation program for coal degasification was not used on all the sites because of their low gas contents.
2. The following Basins have been evaluated as having potential for profitable methane degasification:

Northern Appalachian
Arkoma
Piceance
Green River
San Juan, and
Tono

3. Relationships have been developed to compare the economic viability of recovering methane at a profit using.
4. No significant relationship between ϕ and coal ranks and type were found.

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6. Diamond, William P., and Oyler, David C.: "Drilling Long Horizontal Coalbed Methane Drainage Holes from a Directional Surface Borehole", SPE/DOE 8968, Proceedings from SPE/DOE Symposium on Unconventional Gas Recovery, Pittsburgh, Pennsylvania, May 18-21, 1980, p. 341-347.

TABLES

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TABLE 1
SIMULATION RESULTS OF PRODUCING
EM-21 WITH H-1 CONNECTED OR NOT CONNECTED
TO OTHER HORIZONTAL WELLS

TIME	EM-20		EM-21		EM-22		EM-23		EM-24		EM-25		EM-26		EM-27	
	Gas Rate Mcf/d	Water Rate BWP/D	Gas Rate Mcf/d	Water Rate BSP/D	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI
WELL H-1 CONNECTED																
89.00	14.3	26.1	0	0	256		244		246		225		256		239	
89.05	14.1	26.0	187.3	300.1	246	-10	240	-4	242	-4	220	-5	249	-7	232	-7
86.00	21.8	24.0	144.9	155.5	245	-1	228	-12	235	-7	217	-3	245	-4	232	0
86.00	26.1	23.3	0	0	239	-6	229	+1	234	-1	215	-2	240	-5	230	-2
WELL H-1 NOT CONNECTED																
89.00	18.5	24.9	0	0	247		238		240		217		247		234	
89.05	18.4	25.0	328.3	300.9	242	-5	236	-2	238	-2	216	-1	245	-2	232	-2
96.00	21.3	23.8	168.8	101.4	235	-7	216	-20	229	-9	214	-2	244	-1	232	0
26.00	25.0	22.8	0	0	233	-2	224	+8	228	-1	211	-4	238	-6	229	-4

TABLE 2
SIMULATION RESULTS OF SWABBING
EM-24, EMERALD MINES PROJECT

WI = 2.

Time Days	EM-20		EM-24					EM-21		EM-22		EM-23		EM-25		Events ¹
	Gas Rate Mcf/d	Water Rate BWPD	Gas Rate Mcf/d	Water Rate BWPD	Blk. Press. psia	Press. Drop psi	BHF psia	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	
84.46	22.0	32.7	0.0	0.0	260		—	255		260		260		255		SS
84.51	22.0	32.7	0.0	295.3	233	-27	109	255		260		260		255		S
84.56	22.0	32.7	0.0	295.3	221	-12	80	255		260		260		255		S
84.67	22.0	32.7	191.7	294.7	136	-85	49	255		260		260		255		ES
85.33	21.6	32.9	0.0	0.0	218	+82	—	255		260		260		255		SS
85.67	21.6	32.9	0.0	271.9	193	-25	60	255		260		260		255		ES
86.33	21.7	32.9	0.0	0.0	216	+23	—	255		260		259	-1	255		SS
86.40	21.7	32.9	309.3	97.1	80	-136	35	255		260		259		255		S
86.50	21.7	32.9	59.5	85.5	70	-10	15	155		260		259		255		ES
87.97	22.0	32.7	0.0	0.0	199	+129	—	255		260		259		255		SI
101.00	21.8	31.6	0.0	0.0	244	+45	—	253	-2	255	-1	259	—	248	-7	SI
Period Total			33Mcf	167.0 bbls.		-16			-2		-1		-1		-7	

¹ SS = Start Swabbing; S = Swabbing; ES = End Swabbing; SI = Shut In

TABLE 3

SIMULATION RESULTS OF SWABBING
EM-24, EMERALD MINES PROJECT

WI = .5

Time Days	EM-20		EM-24					EM-21		EM-22		EM-23		EM-25		Events ¹
	Gas Rate Mcfd	Water Rate BWPD	Gas Rate Mcfd	Water Rate BWPD	Blk. Press. psia	Press. Drop psi	BHP psia	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	
84.46	22.0	32.7	0.0	0.0	260	—	—	255	—	260	—	260	—	255	—	SS
84.51	21.7	32.6	0.0	115.7	243	-11	15	255	—	260	—	260	—	255	—	S
84.55	21.6	32.6	0.0	112.3	243	-6	15	255	—	260	—	260	—	255	—	S
84.67	21.6	32.7	0.0	107.6	236	-7	15	255	—	260	—	260	—	255	—	ES
85.33	21.6	32.9	0.0	0.0	253	+17	—	255	—	260	—	260	—	255	—	SS
85.67	21.6	32.9	0.0	102.1	232	-21	15	255	—	260	—	259	-1	255	—	ES
86.35	21.7	32.9	0.0	0.0	247	+15	—	255	—	260	—	259	—	255	—	SS
86.50	21.7	32.9	33.8	77.9	182	-35	15	255	—	260	—	259	—	255	—	ES
88.53	21.9	32.7	0.0	0.0	240	+58	—	255	—	260	—	259	—	255	—	SI
101.00	21.9	31.6	0.0	0.0	255	+15	—	253	-2	260	—	259	—	248	-7	SI
Period Total			4Mcfd	66.0 bbls		-5			-2		0		-1		-7	

¹ SS = Start Swabbing; S = Swabbing; ES = End Swabbing; SI = Shut In

TABLE 4

**SIMULATION RESULTS OF SWABBING
EM-24, EMERALD MINES PROJECT**

WI = .1

Time Days	EM-20		EM-24					EM-21		EM-22		EM-23		EM-25		Events ¹
	Gas Rate Mcf/d	Water Rate BWPD	Gas Rate Mcf/d	Water Rate BWPD	Blk. Press. psia	Press. Drop psi	BHP psia	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	Blk. Press. psia	Press. Drop psi	
84.46	220	32.7	0.0	0.0	260	—	—	255	—	260	—	260	—	255	—	SS
84.51	21.7	32.6	0.0	24.1	257	-3	15	255	—	260	—	260	—	255	—	S
84.56	21.6	32.6	0.0	23.9	256	-1	15	255	—	260	—	260	—	255	—	S
84.63	21.6	32.6	0.0	23.8	255	-1	—	255	—	260	—	260	—	255	—	S
84.67	21.6	32.7	0.0	23.7	254	-1	15	255	—	260	—	260	—	255	—	ES
85.33	21.6	32.9	0.0	0.0	258	+4	—	255	—	260	—	260	—	255	—	SS
85.67	21.6	32.9	0.0	23.4	253	-5	15	255	—	260	—	260	—	255	—	ES
86.33	21.7	32.9	0.0	0.0	257	+4	—	255	—	260	—	260	—	255	—	SS
86.50	21.7	32.9	0.0	23.4	253	-4	15	255	—	260	—	260	—	255	—	ES
89.80	22.0	32.6	0.0	0.0	258	+5	—	255	—	260	—	260	—	254	-1	SI
101.00	21.8	31.7	0.0	0.0	259	+1	—	253	-2	260	—	259	-1	248	-6	SI
Period Total			0 Mcf	16.0 bbis		-1			-2		0		-1		-7	
No Production From Well EM-24																
101.00	21.5	31.7	0.0	0.0	259	-1	—	254	-1	260	0	259	-1	248	-7	SI

¹ SS = Start Swabbing; S = Swabbing; ES = End Swabbing; SI = Shut In

TABLE 5
SIMULATION RESULTS OF PRODUCING EM-21 WITH H-1
CONNECTED OR NOT CONNECTED TO OTHER HORIZONTAL WELLS(EM-21, WI = .2)

TIME	EM-20		EM-21		EM-22		EM-23		EM-24		EM-25		EM-26		EM-27	
	Gas Rate Mcf/d	Water Rate BWP/D	Gas Rate Mcf/d	Water Rate BWP/D	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI
<u>H-1 CONNECTED EM-21 PRODUCING 8 HRS/DAY</u>																
389.3333	19.0	25.0	0	0	243.15		234.66		238.53		217.43		245.33		233.64	
389.3833	18.8	25.2	35.7	34.6	243		235		239		217		246		234	
389.6667	19.0	25.1	26.1	35.0	243		234		238		217		246		234	
390.3333	19.2	25.0	0	0	243		234		238		217		247		234	
390.6667	19.4	25.0	26.2	35.1	243		234		238		217		246		234	
391.3333	19.7	25.0	0	0	243		234		238		217		246		234	
391.6667	19.9	24.9	27.3	35.1	243		234		238		217		246		234	
392.3333	20.1	24.9	0	0	243		234		238		217		246		234	
392.6667	20.3	24.8	26.8	35.0	242		234		238		217		246		234	
393.3333	20.5	24.8	0	0	242		233		238		217		246		234	
393.6667	20.7	24.7	0	0	242		233		238		217		245		234	
394.3333	20.9	24.7	0	0	242		233		237		217		245		234	
394.6667	21.0	24.6	27.9	34.7	242		233		237		217		245		234	
395.3333	21.2	24.6	0	0	242		233		237		217		245		233	
395.6667	21.3	24.5	29.6	34.7	241.79	-1.35	232.65	-2.01	237.04	-1.49	216.70	-0.73	244.66	-0.67	233.45	-0.19
426.0000	24.1	23.6	0	0	236.04	-5.75	228.23	-4.42	231.98	-5.06	213.69	-3.01	239.00	-5.66	228.17	-5.28
PERIOD TOTAL			66Mcf	82Bbls.		-7.11		-5.43		-6.55		-3.74		-6.33		-5.47

TABLE 5
(Continued)

SIMULATION RESULTS OF PRODUCING EM-21 WITH H-1
CONNECTED OR NOT CONNECTED TO OTHER HORIZONTAL WELLS(EM-21, WI = .2)

TIME	EM-20		EM-21		EM-22		EM-23		EM-24		EM-25		EM-26		EM-27	
	Gas Rate Mcf/d	Water Rate BWPD	Gas Rate Mcf/d	Water Rate BWPD	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI
H-1 NOT CONNECTED EM-21 PRODUCING 8 HRS/DAY																
389.3333	15.1	25.5	0	0	244.39		236.98		239.80		217.11		245.61		233.27	
389.3833	14.9	25.5	38.4	35.2	245		237		240		217		246		233	
389.6667	15.0	25.5	31.5	34.7	245		237		240		217		247		233	
390.3333	15.5	25.9	0	0	245		237		240		217		247		233	
390.6667	15.9	25.9	31.9	34.7	245		236		240		217		247		233	
391.3333	16.4	25.8	0	0	245		236		240		217		247		234	
391.6667	16.7	25.7	34.0	34.7	245		236		240		217		247		234	
392.3333	17.1	25.6	0	0	245		236		239		217		247		234	
392.6667	17.3	25.5	32.4	34.5	245		236		239		217		247		234	
393.3333	17.7	25.4	0	0	245		236		239		217		246		233	
393.6667	17.9	25.3	34.2	34.2	244		235		239		217		246		233	
394.3333	18.2	25.2	0	0	244		235		239		217		246		233	
394.6667	18.4	25.2	33.8	34.2	244		235		239		217		246		233	
395.3333	18.7	25.1	0	0	244		235		239		217		246		233	
395.6667	18.8	25.1	36.9	34.1	243.95	-0.44	234.56	-2.42	238.67	-1.13	216.93	-0.18	245.36	-0.25	233.31	+0.04
426.0000	23.5	23.8	0	0	238.42	-5.53	230.88	-3.68	233.44	-5.23	214.21	-2.72	239.63	-5.73	228.44	-4.87
PERIOD TOTAL			80Mcf	81Bbls.		-5.97		-6.10		-6.35		-2.90		-5.98		-4.83

TABLE 6
SIMULATION RESULTS OF PRODUCING EM-21 WITH H-1
CONNECTED OR NOT CONNECTED TO OTHER HORIZONTAL WELLS (EM-21, WI = .2)

TIME	EM-20		EM-21		EM-22		EM-23		EM-24		EM-25		EM-26		EM-27	
	Gas Rate Mcf/d	Water Rate BWPd	Gas Rate Mcf/d	Water Rate BWPd	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI	Blk. Pres. PSIA	Pres. Drop PSI
H-1 CONNECTED EM-21 PRODUCING 24 HRS/DAY																
389.3333	19.0	25.0	0	0	243.15		234.66		238.53		217.43		245.33		233.64	
396.3333	21.8	24.3	29.5	33.7	240.93	-2.22	230.73	-3.93	235.61	-2.92	215.98	-1.45	243.92	-1.41	233.17	-0.47
426.0000	24.9	23.4	0	0	235.28	-5.65	227.24	-3.49	231.07	-4.54	213.12	-2.86	239.43	-5.49	227.85	-5.32
PERIOD TOTAL			196Mcf	239Bbls.		-7.87		-7.42		-7.46		-4.31		-6.90		-5.79
39	H-1 NOT CONNECTED EM-21 PRODUCING 24 HRS/DAY															
389.3333	15.1	25.5	0	0	244.39		236.98		239.80		217.11		245.61		233.27	
396.3333	18.7	24.9	41.6	31.6	242.20	-2.19	230.03	-6.95	236.78	-3.02	216.48	-0.63	244.82	-0.79	233.10	-0.17
426.0000	23.7	23.7	0	0	237.66	-4.54	230.12	+0.09	232.79	-3.99	213.84	-2.64	239.33	-5.49	228.24	-4.86
PERIOD TOTAL			266Mcf	228Bbls.		-6.73		-6.86		-7.01		-3.27		-6.28		-5.03

TABLE 7

SUMMARY OF CORING AND GAS CONTENT DATA ON WELL TEST PACKAGES RECEIVED

Basin	Well Site Designation	Total Coring Footage (ft.)	Total Coal Footage (ft.)	Desorption Samples Taken (No.)	Gas Content Range (cc/g)	Evaluated (Report No.)
No. Appalachian	AAA	SW	34.	7	1.04-13.3	2
	AAB	2473.0	40.9	13	2.2-6.2	3
	AAC	55.2	12.15	5	4.4-9.8	3
Worrior	CAA	211.5	18.5	4	.54-3.24	3
Illinois	DAA	194.0	7.0	7	.9-1.5	1
	DAB	28.5	14.5	6	.7-1.1	
	DAE	65.0	12.7	4	1.4	
Arkoma	EAA	48 SW	11.0	3	2.27-6.60	1
	EAB	15.9	13.0	1	7.25	2#
	EAC	43.7		0	ND	
Piceance	FAA	0	ND	2	.56-2.5	1
	FAB	0	ND	0	ND	1
	FAC	206.6		9	1.03-4.6	1
	FAD	42.9	10.3	5	1.8-2.1	
	FAE	79.3	27.63	8	.6-2.8	
	FAF	45.1	10.13	7	.14-.3	
	FAG	29.3	11.9	3	1.0-1.3	
	FAH	106.5	22.0	3	.22-.49*	
	FAI	68.0	41.3	14	1.291-8.90	3
	FAK	146.6	38.9	8	2.6-5.9	3
Green River	GAA	150.0	15.8	14	.58-11.76	1
		+30 SW		12	2.81-6.56	
	GAB	90.9	18.7	9	1.04-16.84	1
		+30 SW		7	1.42-10.93	
	GAC	0	38.0	4	.4-.8*	
San Juan	HAA	43.5	12.2	2	.5-2.3	3
	HAB	0	18.5	3	2.0	3
	HAC	44.2	42.0	5	.4-.7	3
	HAD	87.0	50.5	8	.1-1.0	3
	HAE	74.0	24.6	6	1.4-2.2	3

TABLE 7
(Continued)

SUMMARY OF CORING AND GAS CONTENT DATA ON WELL TEST PACKAGES RECEIVED

Basin	Well Site Designation	Total Coring Footage (ft.)	Total Coal Footage (ft.)	Desorption Samples Taken (No.)	Gas Content Range (cc/g)	Evaluated (Report No.)
Powder River	IAA	94.7	87.1	6	.04-.08*	
	IAB	132.5	74.2	10	.03-.13	
	IAC	160.5	108.8	10	.02-.41	
	IAD	113.7	74.4	4	.7-1.0	
	IAE	133.5	83.1	6	.04-1.2	
	IAF	30.0	24.3	4	.1-.7	
	IAG	NC	ND	9	.2-1.47	
	IAH	NC	ND	7	.0-.23	
Tono	LAA	236.0	21.7	4	1.05-2.334	3
Wind River	NAA	73.0	9.3	4	.02-.08	
	NAB	46.0	11.8	2	.03-.05	
	NAC	10.9	5.6	1	.03	

Footnotes:

SW = Sidewall Cores

ND = Not Determined

* = Preliminary Sample Desorption

Report No. 1 - INTERCOMP, April 1979

Report No. 2 - INTERCOMP, August 1980

Report No. 3 - This Report

= A Sensitivity Study Only

TABLE 8
Form Used in Evaluating Well Test Data

BASIN:

IDENTIFICATION:

TYPE OF TEST:

WELL OWNER:

WELL NAME:

WELL LOCATION:

WELL ELEVATION:

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 1C Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

TABLE 9

BASIN: NORTHERN APPALACHIAN

IDENTIFICATION: AAA

TYPE OF TEST:

WELL OWNER: The Harry A. Murdick, Jr.,

WELL NAME: Kinloch Well #1 Stoner & #1 Murdock

Farm #, Whiteley Township

WELL LOCATION: Greene County, Pennsylvania

WELL ELEVATION:

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
329-333	4.	Waynes burgh		1.04			#1 Murdock
658-664	6.	Pittsburgh		1.95			#1 Murdock
422-426	4.	Pittsburgh		3.3			#1 Stoner
825-826	1.	Parkerstown		7.6			#1 Stoner
1003-1005	2.	U. Freeport		8.3			#1 Stoner
1155-1156	1.	M. Kittanning		6.7			#1 Stoner
1101-1244	26 in 4 zones	L. Kittanning-Clarion		13.3			#1 Stoner
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	34 ft Stoner #1			Avg = 6.03 Wtd. Avg = 9.22			9.2

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	11,627	200	150 K	1.0	424	1	9.22	
MAXIMUM LIKELY	34,707	500	100 K	1.0	424	1	9.22	
MINIMUM LIKELY	6,952	200	150 K	.5	424	2	9.22	

Depth = 1101 ft
 Press = 424/14.65 = 28.9 Atmos.

TABLE 10

BASIN: Northern Appalachian

IDENTIFICATION: AAB

TYPE OF TEST: IV - 1

WELL OWNER: Waynesburg College
Waynesburg Boro, Thayer Hall Tract

WELL NAME: Core Hole #1 and #2

WELL LOCATION: Greene Co., Penn

WELL ELEVATION: 946.5 ft.

CCAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coa.	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
148.8 - 154.8	6.0	Waynesburg	hvAb	2.9, 2.2 = 2.5	No Data	No Data	
370.9 - 374.6	3.7	Sewickley	hvAb	4.8			
480.0 - 486.2	6.2 (Poor)	Pittsburgh (Riders & Shale)	hvAb	4.6, 4.2 = 4.4			Riders & Shale
486.2 - 492.5	6.3	Pittsburgh (Main Bench)	hvAb	5.6, 4.2 = 4.9			
887.8 - 891.0	3.2	Bakerstown	hvAb	4.3			
1034.3 - 1085.9	0.7	Upper Freeport	hvAb	3.6			
1186.5 - 1188.5	2.0	Upper Kittanning	hvAb	4.8, 6.2 = 5.5			
1237.0 - 1239.5	2.0 (Pocr)	Middle Kittanning	hvAb	3.1			Coal and Coaly Shale
1243.0 - 1248.0	5.0 (Pocr)	Middle Kittanning	hvAb				Coal and Coaly Shale
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type?	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

TABLE 10 - Continued

BASIN: Northern Appalachian IDENTIFICATION: AAB TYPE OF TEST: IV - 1
 WELL OWNER: Waynesburg College WELL NAME: Core Hole #1 and #2
 WELL LOCATION: Waynesburg Boro, Thayer Hall Tract
 Greene Co., Penn WELL ELEVATION: 946.5 ft

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
1291.8 - 1294.3	2.5	Lower Kittanning	lvAb	4.4			
1291.2 - 1403.4	2.2	Clarion - Brookville	lvAb				
1407.4 - 1408.5	1.1	Clarion - Brookville	lvAb				
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
TD=1439	40.9	?	High-Volatile A bituminous	Avg = 4.17 Wtd Avg = 4.04	No Data	No Data	6.185

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	12,568	200	100,000	20	360	3	Special Curve	AABMO
MAXIMUM LIKELY	72,142	500	100,000	20	360	2	Special Curve	AABMA
MINIMUM LIKELY	3,185	0	0	20	360	3	Special Curve	AABMI

TABLE 11

BASIN: NORTHERN APPALACHIAN

IDENTIFICATION: AAC

TYPE OF TEST:

WELL OWNER: Rochester & Pittsburgh Coal Co.

WELL NAME: DDH 2355

WELL LOCATION: Indiana County, Pennsylvania

WELL ELEVATION: 1280 ft (Surface)

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
5759-582.65	6.75	Upper Freeport (E)	ND	0.0 ²	ND	ND	
654.8-656.8	2.0	U. Kittanning (C) ¹		4.4			Blocky, Vertically Cleated
756.8-760.2	3.4	L. Kittanning		0.3*, 9.8			Blocky, Calcite in Cleats
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
780	12.15	?		Avg = 4.73 Wt. Avg = 7.89			3.565

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	10,099	200	150 K	10	215.4	2	7.8	W/O Upper Freeport (E)
MAXIMUM LIKELY	28,443	500	100 K	50	215.4	2	7.8	-
MINIMUM LIKELY	2,502	200	150 K	1.0	215.4	2	7.8	-

¹ Coal, bony from 5759-578 and 581.6-582.65

Clean coal from 573-581.6, bright bands, vertical cleat, some pyrite laminae, blocky, Upper Freeport (E) Coal

* Canister Leaked

² 2 Samples Taken. No gas, samples removed from canisters

$$\text{Pressure} = \frac{760.2 + 575.9}{2} \times .3 + 15 = 215.4 \text{ psia}$$

³ W/O Upper Freeport

TABLE 12

BASIN: WARRIOR

IDENTIFICATION: CAA

TYPE OF TEST:

WELL OWNER: Grace Petroleum Corp.

WELL NAME: Well No. 1 Grimsley 35-15

WELL LOCATION: Sec.34,T143,R11W
Fayette County, Alabama

WELL ELEVATION:

COAL SEAM DATA

Density Log Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks from Core
165	2.0	Unnamed					
563	2.0	Mary Lee					
593	2.5+1.5 rock part	Blue Creek	HvBb	2.77			Parting in Middle, soft-friable
747	2.5	Black Creek					
860	2.0	Unnamed					
1100	2.0	Unnamed (ft)		3.24			soft-friable
1675	2.5	Rosa	HvHb	0.54			hard-blocky
1879	3.0	Tidmore E	HvAb	2.2			Platy
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
2410	18.5	?	Mixed	Avg = 2.19 Wt. Avg = 2.02			1.406

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	425	0	0	1.0	580	2	2.02	Depth = 1412 Ft.
MAXIMUM LIKELY	13771	200	150	10.	580	2	2.02	Depth = 1412 Ft.
MINIMUM LIKELY	52	0	0	.5	249	2	2.02	Depth = 585 Ft.

Note: Depth & Width Data From Porosity Log

Press = 580/14.65 = 39.6 atmos.

Press = 249/14.65 = 17.0

TABLE 13

BASIN: ILLINOIS

IDENTIFICATION: DAA

TYPE OF TEST:

WELL OWNER: Hagen Oil Co.
S19 T3N R&E

WELL NAME: Henderson #2

WELL LOCATION: Clay County, Illinois

WELL ELEVATION: 451'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
994.9-996.75	2.75	Genville #2 (U. Carbonate)	HvBb, HvBb	1.3, 1.2 = 1.25	11.4	0.15	
1035.5-1037.5	2.0	Herrin #6 (")	HvBb, HvBb	9.1, 1.1 = 1.0	6.4	0.15	
1076.75-1078	1.25	Briar Hills #5A &	HvBb	1.0			
1089.6-1091.1	1.5	Harrishigh #5 (Carbonate)	HvBb	1.2			
1351.75-1091.1	0.5	Seelyville (U. Spoon)	HvBb	1.5			
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	7.0		Iv3b	Avg = 1.17 Wtd. Avg = 1.32			

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

TABLE 14

BASIN: ILLINOIS

IDENTIFICATION: DAB

TYPE OF TEST:

WELL OWNER: VIIICA Coal Association
S7, T2N, R2E

WELL NAME: 722-ICD (Geo West)

WELL LOCATION: Marion County, Illinois

WELL ELEVATION: 537'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
652.7-654.2	1.5	Coal #8					
663.8-666.6	2.8	Danville #1 (H. Carbonate)	HvCb	0.8			
693.9-699	5.1	Herrin #6 (H. Carbonate)	HvCb	1.1			
726.8-727.7	.9	Briarhill #5A	HvBb	0.7	16.9	4.8	
732.3-736.5	4.2	Harrisburgh #5	HvBb				
		(Carbondale)	HvBb, HvBb	.8, .9, .8 = .83	8.5	.04	
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	14.5			Avg = .85 Wtd. Avg. = .92	9.98	.88	

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

TABLE 15

BASIN: ILLINOIS

IDENTIFICATION: DAE

TYPE OF TEST:

WELL OWNER: Richard W. Beeson
S4, T12, R24, (Carter Coordinates)

WELL NAME: Coy Vanby Griff Stratigraphic Test

WELL LOCATION: Webster County, Kentucky

WELL ELEVATION: 541'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
1200-1205.7	5.7	#13 (Usman)	HvAb, #vAb	1.4, 1.4 = 1.4			
1304.7-1309.7	5.0	#9 (Carbonate)	HvAb, HvAb	1.4, 1.4 = 1.4			
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	12.7		HvAb	Avg = 1.4 Wtd. Avg = 1.4	HvAb		

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (mc)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

TABLE 16

BASIN: PICEANCE CREEK

IDENTIFICATION: FAI

TYPE OF TEST:

WELL OWNER: Teton Energy
NW $\frac{1}{4}$, NW $\frac{1}{4}$, S23, T10S, R95W

WELL NAME: Walck 23-2

WELL LOCATION: Mesa County, Colorado

WELL ELEVATION: 7017.8'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
4682-4696	1.8	Cameo (Mesa Verde)		1.291			
4724-4731	7	Cameo (Mesa Verde)		4.148, 5.028, 1.019, 3.25 = 3.374			coal cuttings
4755.7-4756.5	0.8	Cameo (Mesa Verde)		5.622			
4755.1-4755.7	0.6	Cameo (Mesa Verde)		8.421			
4756.5-4756.7	0.2	Cameo (Mesa Verde)		8.421			
4801-4801.8	.8	Cameo (Mesa Verde)		8.364			
4808-4808.3	.3	Cameo (Mesa Verde)		5.685			coal is dull
4753-4753.8	0.8	Cameo (Mesa Verde)		5.786			
4796-4808	12	Cameo (Mesa Verde)		1.816, 8.877 = 6.862			coal & cuttings
4804-4804.8	.8	Cameo (Mesa Verde)		8.90			
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	41.3'	Cameo Coals		Avg = 5.69 Wtd. Avg = 3.89			4.477

PRODUCTION POTENTIAL, Φ , ANALYSIS (1/4 of total well)

CASE	Φ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	19,112	1000	50 K	1.	1675	2	3.89	
MAXIMUM LIKELY	56,589	1000	150 K	10	1675	2	3.89	
MINIMUM LIKELY	14,371	500	100 K	.5	1675	2	3.89	

$$\text{Press} = \frac{(4682 + 4805)}{2} \times .35 + 15 = 1675 \text{ psia}$$

$$\text{Press} = 1675/14.55 = 114.35 \text{ atmos.}$$

TABLE 17

BASIN: PICEANCE CREEK

IDENTIFICATION: FAK

TYPE OF TEST:

WELL OWNER: Adolph Coors Co.

WELL NAME: Nichols 1-23 cm

S23,10S,97W,NE 1/4 of SW 1/4 of NE 1/4

WELL LOCATION: Mesa County, Colorado

WELL ELEVATION: 5966'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
2675-2680	5.0	(Mesa Verde) Camec		3.0			Black, blocky & Dull
2770.1-2700.6	.5	(Mesa Verde) Camec					Black, Blocky & Dull
2712.4-2712.8	.4	(Mesa Verde) Camec					Black, Conchoidal, fracture
2713.2-2713.9	.7	(Mesa Verde) Camec					Blocky, Black, silky, bright & bandy
2714.2-2726	11.8	(Mesa Verde) Camec		3.0, 4.3 =			Blocky, Black, Silky, bright & bandy
2732.1-2742	9.0	(Mesa Verde) Camec		2.6, 2.9 =			Blocky Interbedded Shale
2748.0-2749.3	.4	(Mesa Verde) Camec					Cleat, Black, silky with bands
2753.8-2756.6	3.6	(Mesa Verde) Camec		5.6			Cleat, Black, silky with bands
2769.4-2776.0	6.6	(Mesa Verde) Camec		5.9, 5 =			Conchoidal frac. dull & blocky
							Long, dull & silky and same + cleat & butte
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	38.9'	Mesa Verde-Camec		Avg = 4.16 Wtd. Avg. = 3.97			5.089

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	14072	1000	50K	1.	969	2	3.97	
MAXIMUM LIKELY	20532	2000	25K	10	969	2	3.87	
MINIMUM LIKELY	5766	500	100 K	.5	969	2	3.97	

$$\text{Press} = \left(\frac{2675 + 2776}{2} \right) \times .35 + 15 = 969 \text{ psia}$$

.35 as Pressure Gradient

Depth = 2725.5 ft

$$\text{Press} = 969 / 4.65 = 66.14 \text{ atmos.}$$

TABLE 18

BASIN: SAN JUAN

IDENTIFICATION: HAA

TYPE OF TEST:

WELL OWNER: Western Coal Co.
SE 1/4, Sec. 22T, 30N, R15W

WELL NAME: Western Coal

WELL LOCATION: San Juan County, New Mexico

WELL ELEVATION: 5247 ft

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
387.3-387.8	5	Fruitland Formation					Fractured Horizontal Cleat
395.5-403.7	8.2	Fruitland Formation	Hyab/Hyab	2.37/51	ND	ND	Sample #694/#695
404.0-407.5	3.5	Fruitland Formation					(Both 1 samples)
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	12.2	?		Avg = 1.41 Wtd. Avg = 1.41			0.647

PRODUCTION POTENTIAL, Φ , ANALYSIS (1/4 of total well)

CASE	Φ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	17,620	500	100,000	10	192	1	1.41	
MAXIMUM LIKELY	51,492	500	100,000	50	192	1	1.41	
MINIMUM LIKELY	4,644	500	100,000	1	192	1	1.41	

Pres = 405 ft x .434 = 177 psi + 15 = 192 psia 13.1 atmos.

TABLE 19

BASIN: SAN JUAN

IDENTIFICATION: IIAB

TYPE OF TEST:

WELL OWNER: Navajo Nation Minerals Department
NW 1/4 of SW 1/4 Sec. 18, T28N, R14W

WELL NAME: K-3

WELL LOCATION: San Juan County, New Mexico

WELL ELEVATION: Surface = 5645 ft

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
680-685	Coal Stringers	Frutland Formation	Probably		No Data	No Data	Assumed 1 ft Coal
685-700	fine coal fragments		Subbituminous				off.
720-730	Coal Stringers Shiny						Assumed 2 ft Coal
755-770	thin coal stringer						Assumed 1/2 ft Coal
805-815	Coal with dull luster			3 samples taken			Assumed 3 ft Coal
815-820	Clean Bright Coal			of cuttings			Assumed 3 ft Coal
820-835	50% bright coal			2 cc/g			Assumed 7 ft Coal
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
835	Assumed 18 1/2 ft	Probably Yes	Subbituminous	2 cc/g			

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Absorption Isotherm (No.)	Remarks
MOST LIKELY	2162	500	25,000	1.0	369	3	2	
MAXIMUM LIKELY	6091	500	25,000	1.0	369	3	2	
MINIMUM LIKELY	1585	500	25,000	.5	369	3	2	

Note: Well produced gas during drilling. Lifting water from 400 to 500 feet.

Press = 815 ft x .434 = 354 psi + 15 psi = 369 psia

TABLE 20

BASIN: SAN JUAN

IDENTIFICATION: IIAC

TYPE OF TEST:

WELL OWNER: The Navajo Nation Minerals Dept,
NW $\frac{1}{4}$, NE $\frac{1}{4}$, SE $\frac{1}{4}$, Sec. 35, T25N, R14W

WELL NAME: #A-5

WELL LOCATION: San Juan County, New Mexico

WELL ELEVATION: 6070 ft

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
683.6-690.4	5.8	Fruitland		.4	ND	ND	Bed "A" Numerous Partings
691.4-701.0	11.6	Fruitland		.5			Bed "A" Numerous Partings
712.4-720.4	8.0	Fruitland		.6			Bed "B"
748.4-756.0	7.6	Fruitland		.7			Bed "C"
756.0-765.0	9.0	Fruitland		.5			Bed "C"
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
878	42	?		Wtd. Avg. = .55 Avg. = .54			0.853

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	1649	1000	50 K	1.0	331	2	.55	
MAXIMUM LIKELY	3190	1000	50 K	10	331	2	.55	
MINIMUM LIKELY	1144	1000	50 K	.5	331	2	.55	

Note: Gas content probably low. Residual and lost gas not included.

Press = 725 ft x .434 = 316 + 15 = 331 psia

TABLE 21

BASIN: SAN JUAN

IDENTIFICATION: I1AD

TYPE OF TEST:

WELL OWNER: J.D. McHugh
see.17, T24N,R2W

WELL NAME: DI's Delight #1

WELL LOCATION: Rio Arriba County, New Mexico

WELL ELEVATION: 7096 ft

COAL SEAM DATA

Depth (ft)	Sample Interval Width (ft)	Name	Type Coal	Gas Does Not Include Lost Gas or Porosity (cc/g)	Des.d Gas Permeability (md)	Remarks	
3039.7-3040.6	.9	Fruitland Formation	Subbituminous	.1		5 Samples	
3033.5-3034.6	1.1	Fruitland Formation		.1		taken of Fruitland Formation	
3043.7-3044.6	.9	Fruitland Formation		.1			
3071.9-3072.8	.9	Fruitland Formation		1.0			
3065.1-3065.9	.9	Fruitland Formation		.2		Six thin shale & sandstone stringers from 0.3 to 0.8' thick	
3058.6-3059.5	.9	Fruitland Formation		.1			
3051.4-3053.3	.9	Fruitland Formation		.1			
3084.7-3086.0	1.3	Fruitland Formation	Higher Rank	.1			
	Total = 7.7						
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
3200	50.5 ft coal with thin SS & Sh stringers	No.	Subbituminous	Wtd. Avg = .22 Avg = .34	46.5% *		0.646

Net Coal = 47.2

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	*dsorpt. on Isotherm (No.)	Remarks
MOST LIKELY	3294	1000	50 K	1.0	1341	3	.34	
MAXIMUM LIKELY	22,765	1000	50 K	10	1341	3	1.0	
MINIMUM LIKELY	2326	1000	50 K	.5	1341	3	.34	

*Com-Pro Log (Birdwell); Acoustic Porosity

91.5 ATM

Press = $\frac{(3032 + 3082 \text{ ft} \times .4341) + 15}{2} = 1341 \text{ psia}$

1 Probably lost significant quantities of gas recovering core at this depth

TABLE 22

BASIN: SAN JUAN

IDENTIFICATION: HAE

TYPE OF TEST:

WELL OWNER: Energy Reserves Group
179ft, 1165ft, 31, 29N, 12W

WELL NAME: Callegos-Canyon Unit #322

WELL LOCATION: San Juan County, N.M.

WELL ELEVATION: 5543'

COAL SEAM DATA

Depth (ft)	Width (ft)	Name Formation	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
1350-1353.1	3.1	Fruitland		2.1, 2.0 =			Vertically, Std. conchoidal fracture
1394.3-1402.1	9.8	Fruitland		1.9, 2.1 =			Vertically, pyrite, thin shale
1404.1-1412.7	8.6	Fruitland		2.2			same as above
1416.6-1419.7	3.1	Fruitland		1.4			Blocky, vertically jointed
							within calc. to filling
							Brown lignitic material
							Low in moisture and sulfur with
							high ash content
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
1249'	24.6'		Avg = 1.95 Wt. Avg. = 2.00				1.351

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	1392	1000	50 K	1.0	616	2	2.00	
MAXIMUM LIKELY	3049	1000	50 K	10	616	2	2.00	
MINIMUM LIKELY	1001	1000	50 K	.5	616	2	2.00	

Drill stem test showed 150 ft gas cut mud & soft water cut mud in pipe with 89 psi pressure at bottom of hole

42.0 ATM

$$\text{Press} = \frac{(1350 + 1420)}{2} \times .434 + 15 = 616$$

TABLE 23

BASIN: TONO

IDENTIFICATION: LAA

TYPE OF TEST:

WELL OWNER: D.O.E.

WELL NAME: D.O.E. 7

WELL LOCATION: Thurston County, Washington

WELL ELEVATION: 256 Ft.

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
602.6-605.1	2.5	Big Dirty	Sb				1 Ft. Sample Taken From 2.5'
(602.8-603.8)	(1.0)*	Big Dirty		2.83			Coal Interval
606.2-606.3	1	Big Dirty					
606.5-607.4	.9	Big Dirty					
607.9-608.4	.5	Big Dirty					
609.3-612.8	3.5	Big Dirty	Sb B to C				1 Ft. Sample Taken From 35'
(610.0-611.0)	(1.0)*	Big Dirty		2.54			Core Interval
613.1-615.2	2.1	Big Dirty	Sb C				
615.5-617.1	1.6	Big Dirty	Sb B				
617.8-618.9	1.1	Big Dirty					
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	21.7	?	Sub bituminous B & C				

PRODUCTION POTENTIAL, Q, ANALYSIS (1/4 of total well)

CASE	Q, CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY								
MAXIMUM LIKELY								
MINIMUM LIKELY								

* One Foot Sample Taken of Longer Coal Interval

TABLE 23 (Continued)

BASIN: TONO

IDENTIFICATION: LAA

TYPE OF TEST:

WELL OWNER: D.O.E.

WELL NAME: D.O.E.7

WELL LOCATION: Thurston County, Montana

WELL ELEVATION: 256 Ft.

COAL SEAM DATA

Depth (ft)	Width (ft)	Name	Type Coal	Gas Content (cc/g)	Porosity (%)	Permeability (md)	Remarks
617.9-618.9	(1.0)*	Big Dirty		1.1	ND	ND	1 Ft. Sample Taken From 1.1's Core Interval
619.3-622.8	3.5	Big Dirty	Sb B				7' Sample Taken From 1.1 Coal
623.2-624.3	1.1	Big Dirty	Sb B				
623.2-623.9	(.7)*			1.05			
Well Depth (ft)	Total Coal (ft)	Coal Below Well Depth?	Main Coal Type	Avg. for Main Coals	Avg. for Main Coals	Avg. for Main Coals	Gas-in-place Bscf/Section
	16.9 Net 21.7 Gross	?		Avg = 1.88 Wt. Avg. = 2.24			1.424

PRODUCTION POTENTIAL, ϕ , ANALYSIS (1/4 of total well)

CASE	ϕ , CUM. 10 Yr. Prod. Disc. 15% (Mcf)	Fracture Length (ft)	Fracture Conductivity (md-in)	Permeability (md)	Pressure (psia)	Krg Curve (No.)	Adsorption Isotherm (No.)	Remarks
MOST LIKELY	86.0	0	0	1.0	229	2	2.24	Depth $\frac{602.6 \text{ to } 623.9}{2} = 613 \text{ Ft.}$
MAXIMUM LIKELY	4552.0	200	15.7 K	10.0	229	2	2.24	
MINIMUM LIKELY	Not Done	0	0	0.5	229	2	2.24	

Cal. Grad = .35 psi/ft of Depth

* Sample Taken From Larger Core Interval
 Press = $229/14.65 = 15.6$ atms.

TABLE 24
SUMMARY OF GAS-IN-PLACE AND PRODUCTION POTENTIAL, ϕ .

Basin	Well Site Designation	Depth to Bottom of Seam (ft.)	Net Thickness of Coal (Ft.)	Depth to Thickness Ratio	Type of Coal	Gas-In-Place (Bsc ³ /section)	Ø Maximum Likely	Ø Most Likely	Ø Minimum Likely
No. Appal-achian	AAA	1244	34.0	37	HvA _D	9.2	34707	11627	6952
	AAB	1408	40.9	34		6.2	72142	12568	3185
	AAC	760	12.15	63		3.6	28443	10099	2502
Warrior	CAA	1882	18.5	102	Lig-HvAb	1.4	13771	425	52
Illinois	DAA	1352	7.0	193	HvA _D	0.2	2000	(1500)	1000
	DAB	736	14.5	51	HvBb-HvCb				
	DAE	1310	12.7	102	AvAb				
Arkoma	EAA	2725	11.0	248	HvAb	1.4	40000	(21750)	3500
	EAB	3652	13.0	281					
	EAC	2610	6.0						
Piceance	FAA*	1623	ND		HvB _D	Flow Test Produced No Gas			
	FAB*	2154	59.0	37					
	FAC*	991	3.2	310	HvB _D				
	FAD	1352	10.3	131	HvCb				
	FAE	809	27.5	29	HvCb				
	FAF	912	10.1	90	HvCb				
	FAG	1206	11.9	101	HvCb				
	FAH	1225	22.0	56	HvBB				
	FAI	4808	41.3	116		4.5	56589	19112	14371
	FAK	2776	38.9	71			20532	14072	5766
Green River	GAA	4706	15.8	298	HvBb	6.6	65000	(40500)	16000
	GAB	3528	18.7	189	HvAb	6.1	90000	(57500)	25000
	GAC	4986	38.0	131	Lig-SubC				
San Juan	HAA	407	12.2	33	HvAb-HvBb	0.6	51492	17620	4644
	HAB	835	18.5	45	SabB	1.4	6091	2162	1585
	HAC	765	42.0	18		0.9	3190	1649	1144
	HAD	3086	50.5	61	SubB	0.6	22768	3294	2326
	HAE	1419	24.6	58		1.9	3049	1392	1001

TABLE 24
(Continued)

SUMMARY OF GAS-IN-PLACE AND PRODUCTION POTENTIAL, $\emptyset$.

Basin	Well Site Designation	Depth to Bottom of Seam (ft.)	Net Thickness of Coal (Ft.)	Depth to Thickness Ratio	Type of Coal	Gas-In-Place (Bscf/section)	$\emptyset$ Maximum Likely	$\emptyset$ Most Likely	$\emptyset$ Minimum Likely
Powder River	IAA	401	87.1	5	Lig.A-Sub.B				
	IAB	673	74.2	9	Sub.B-HvCb				
	IAC	770	108.8	7	Sub.B-HvCb				
	IAD	752	74.4	10					
	IAE	640	83.1	8					
	IAF	604	24.3	25					
	IAG	2170	ND						
	IAH	2685	ND						
Tono	LAA	624	21.7	29					
Wind River	NAA	972	9.3	105					
	NAB	192	11.8	16					
	NAC	190	5.6	34					

Notes:

* = Sites FAA, FAB and FAC Evaluated Together

ND = No Data

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FIGURES

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KEY MAP
GREENE COUNTY, PA

FIGURE I
Location of Drill Sites and Actual
Well Paths, Emerald Mine Horizontal Drilling Project

LEGEND

MD - Measured depth from surface
HD - Horizontal drilled distance from end of casing

 *
 * +PT-(SH("J
 *
 * EMERALD MINE
 *

FIGURE 6 - COMPARISON OF SIMULATED VS. OBSERVED PRESSURES FOR WELL EM-24

WELL 15

AVG PRESSURE PSIA

(CALC SYM-C OBS SYM-O)

TIME, DAYS

C - SIMULATION PRESSURES
O - OBSERVED PRESSURES

FIGURE 7 - COMPARISON OF SIMULATED VS. OBSERVED PRESSURES FOR WELL EM-25

4-21-61 54("J

PRESSURES FOR WELL EM-26

WELL 17

AVG PRESSURE PSIA

(CALC SYM-C OBS SYM-O)

TIME, DAYS

C - SIMULATION PRESSURES

O - OBSERVED PRESSURES

FIGURE 9 - COMPARISON OF SIMULATED VS. OBSERVED PRESSURES FOR WELL EM-27

FIGURE 10 - PRODUCTION FROM WELL EM-20 FROM FEBRUARY 11 TO JUNE 30, 1980

FIGURE II — MODEL PREDICTION WITH WELL EM-20 NOT IN DIRECT COMMUNICATION WITH HORIZONTAL WELLS

FIGURE 12 - MODEL PREDICTION WITH WELL EM-20 IN DIRECT COMMUNICATION WITH HORIZONTAL WELLS

FIGURE 13 - MODEL PREDICTION WITH WELL EM-20 IN DIRECT COMMUNICATION WITH HORIZONTAL WELLS

FIGURE 14
 Northern Appalachian Basin, Target Area and Well Sites
 (From UGR Semi-Annual/September 1980)

FIGURE 15
Production Rates for Test Site AAA

FIGURE 16
ADSORPTION ISOTHERM FOR SITE AAB

FIGURE 17
PREDICTED PRODUCTION RATES FOR
1/4 PATTERN AND 10 FEET SITE AAB

FIGURE 18
Production Rates for Test Site AAC

FIGURE 20
Production Rates for Test Site AAC

FIGURE 22
Arkoma Basin, Target Area and Well Sites
(From UGR Semi-Annual/September 1980)

FIGURE 23
Piceance Basin, Target Area and Well Sites

FIGURE 24
Production Rates for Test Site FAI

FIGURE 25
Production Rates for Test Site FAK

FIGURE 26
Greater Green River Coal Region, Target Area and Well Sites

FIGURE 27
San Juan Basin, Target Area and Well Sites

FIGURE 28
Powder River Basin, Target Area and Well Sites

FIGURE 29
Production Rates for Test Site HAA

FIGURE 30
Production Rates for Test Site HAB

FIGURE 31
Production Rates for Test Site HAC

FIGURE 32
Production Rates for Test Site HAD

FIGURE 33
Production Rates for Test Site HAE

FIGURE 34
Tono Basin Target Area and Well Site
(From UGR Semi-Annual/September 1980)

FIGURE 35
Production Rates for Test Site LAA

FIGURE 36
THE PROFITABILITY RELATIONSHIP
OF Φ AND WELL DEPTH

FIGURE 37
THE PROFITABILITY
RELATIONSHIP OF Φ AND D/h

FIGURE 38
BASIN DESIGNATION INDICATING
PROFITABILITY ON Φ Vs. D/h PLOT