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**ENERGY FROM TRUE IN SITU PROCESSING OF ANTRIM SHALE—
EXTRACTION TRIALS IN AN EXPLOSIVELY FRACTURED SITE**

Tropical Report

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The Dow Chemical Company
Process Development Department
Midland, Michigan

U. S. DEPARTMENT OF ENERGY

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ABSTRACT

Three in situ energy extraction trials were conducted at The Dow Chemical Company's oil shale site, in Michigan's Sanilac County, near the town of Peck. Here the Antrim shale layer occurs between 1200 and 1400 feet underground. The trials began on October 14, 1979 and ended on April 1, 1980. The three trials, lasting 7, 60 and 17 days respectively, were conducted in a formation prepared by explosive fracturing. Ignition energy was generated with a methane burner and ignition services were provided by TOR Developments, Inc. . Some energy in the form of a dilute fuel gas (5-50 btu/scf) was recovered in each trial but upon ignition drastic decreases in flow communication occurred between injection and production wells. That problem prevented the planned exploration of techniques which would raise the energy value of the production gas. Upon cool down of the formation after each trial, air permeability tests showed inter-well communication levels returning to near preburn levels. Thermal expansion is the most likely cause of the reduced permeability experienced under retorting conditions.

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INTRODUCTION

In late 1976, The Dow Chemical Company entered into a four-year contract with the Department of Energy to investigate the feasibility of recovering energy from Michigan's Antrim shale by an in situ process. This process requires that combustion be initiated in situ to consume part of the organic content of the shale to produce heat. The heat from the combustion process serves to retort the kerogen, thereby driving off a portion of it as a combustible gas or oil. The contract required that an in situ extraction trial be made using an existing site in which Dow had previously drilled several wells. This work has been reported previously (Reference 1). The contract also required that three techniques be tried and evaluated for in situ fracturing and that the site which appeared to be most promising be used in a second in situ extraction trial. The results of this second set of extraction trials are the subject of this report.

The extraction trial site, is located in the "Thumb" of Michigan near the small town of Peck (Figure 1). General views of the site and facilities are shown in Figures 2 and 3. A total of 34 wells were drilled on the 80 acre site.

Previous Trials

Prior to the DOE contract, several unsuccessful attempts to ignite the shale were made at the Peck site. A major shortcoming was the lack of a reliable ignition system. Successful shale ignitions were achieved in 1977 and 1978.

Wells Used For These Trials

After the '77 and '78 experiments, the extraction trials then moved to another location on the site to a cluster of seven wells referred to as the 300 series wells. Figure 4 shows well locations. Three of the 300 series wells (301,306,307) had been explosively fractured. Descriptions and details of the fracturing, well preparation and logging are contained in Reference 2.

Caliper logs of the cavities of wells 301, 306 and 307 are presented in Figure 5.

Extraction trials were conducted during the period of October 14, 1979 to April 1, 1980. A summary description of the three trials is found in Table 1. Shale was ignited in each trial. The first trial, F80-1, ended prematurely because of the burn-off of most of the downhole hardware in the injection well. Trial F80-2 began on November 27, 1979 with an improved design of injection well hardware (Reference 3).

During trial F80-2, 75% of the injected gases were not recovered. Consequently the results are not conclusive. However over 78% of the injected gases were recovered in trial F80-3. This trial provided definitive data and is discussed first in this report.

FIGURE 1

FIGURE 2

FIGURE 3

SITE LAYOUT & WELL LOCATIONS

WELL LOCATIONS IN W 1/2 OF NE 1/4 OF SECTION 8, T9N,
R15E FREMONT TWP., SANILAC CO., MICHIGAN

FIGURE 4

Post Explosive Caliper Logs Wells 306, 301, 307

FIGURE 5

Goals Of Extraction Experiment

The primary goals of the energy extraction phase of the experiment were:

1. Ignite Shale.
2. Demonstrate sustained combustion of shale.
3. Extract energy.
4. Evaluate burn strategies for optimizing energy extraction.

Method

The method utilized in these experiments was true in situ retorting. The shale is thermally reacted in place with no conventional underground mining employed to create void space. The true in situ method is shown diagrammatically in Figure 6.

FIGURE 6

(from Reference 9)

TABLE 1

SUMMARY DESCRIPTION OF TRIALS

(All Energy Values Are Millions of BTU'S)

	<u>F80-1</u>	<u>F80-2</u>	<u>F80-3</u>
Length of Trial (days)	7	60	17
Commencing on	10-14-79	11-27-79	3-13-80
Injection Well No.	301	301	305
Primary Production Well	305	305	306
Reason for Terminating	Loss of Downhole Equipment	Low Recovery of Injected Gases	High Resistance to air Injection
Energy Injected as Methane	-	409	68
Total Energy In	-	1696	354
Energy Out (Gas Heating Value)	-	63	10
Total Energy Out	-	140	120
% Injected Gas Recovered	50	25	78

Ignition System (Reference 3)

Ignition energy was supplied by a methane burner. The burner, methane compressor and the igniting service were provided by Tor Developments, Inc. of Dallas, Texas. Light-off of the burner was achieved by lowering a hypergolic material, triethyl borane, on a wire line down the methane feed line to the burner. Re-lighting was possible and was performed many times during these trials using this method. Typical energy input with the Tor burner was 200 M BTU/hr. Typical gas exhaust temperature from the burner was 650°C.

Analytical System (Reference 4)

The primary analytical systems were:

1. On-line gas analysis by gas-liquid chromatography.
2. On-line gas analysis by continuous nondispersive infrared absorbance for CO, CO₂ and total hydrocarbons.
3. On-line gas analysis by paramagnetic resonance for O₂.
4. Condensable liquid sampling and analysis.

The analytical instruments were in a trailer 500 feet from the wells. Gas samples were transferred to the trailer through 1/8 inch diameter tubing. Figure 7 is a schematic of the system. At the well head, the sample stream was heated and filtered before transfer to the trailer.

At the analytical trailer, sample selection, data collection and processing was automatically sequenced and coordinated by a Perkin Elmer Sigma-10 minicomputer. Reports were printed out in the control room and simultaneously stored on magnetic tape and on magnetic discs in the on-site computer.

The process gas analyzers were also used to monitor downhole burner performance. A high sample gas velocity plus fast responding continuous analysers allowed burner flameout detection before downhole conditions became an explosion hazard. Flameout detection times were less than two minutes.

Data Collecting and Handling (Reference 5)

Data were collected by three procedures:

1. Data were logged manually every hour.
2. Data were entered manually into computer storage (D.E.C. PDP-11) daily.
3. Data were entered automatically into computer storage by twice hourly scanning (D.E.C. PDP-8E, on-site).

ANTRIM SHALE PROJECT ANALYTICAL SYSTEM

FIGURE 7

The PDP-11 was programmed to give daily and cumulative mass and energy balances. A listing of the daily mass and energy inputs and outputs for F80-2 and F80-3 are found in Appendix A. These data are examined in the discussion section of F80-2.

Process Control (Reference 6)

The process was remotely monitored and controlled from a control room 1500 feet from the 300 series wells. A skid supporting the field instruments and control devices was positioned at each well. A flow diagram of the process control system is shown in Figure 8. Each skid had facilities for metering air and nitrogen to a well and for measuring and controlling production gases from a well. Two additional skids labeled "4 Holer" and "Total Flow", were used to give added control flexibility to the production gas stream plus a second check on the production rate of those gases.

Methane Supply

Commercial grade methane, minimum purity 93%, was supplied in tube trailers from Linde Div., Union Carbide Corporation. Each tube trailer contained over 100 M scf at 2000 psig as delivered. The tube pressure was used to feed the methane to the injection well until the pressure in the tubes diminished to well pressure. At that point the Tor reciprocating compressor provided the required pumping to empty the tubes. For increased safety the methane tube trailers and compressor were located over 1000 feet from the 300 series wells.

Air Supply (Reference 6)

Two diesel powered Ingersoll Rand three stage air compressors provided combustion air. Each compressor had a nominal rating of 300 scfm at 1500 psig.

Nitrogen Supply

A liquid nitrogen storage and gasifier system was located on site. Liquid storage capacity was equivalent to 450 M scf of gas. The gasifier system could deliver 120 scfm at 2200 psig.

FLOW DIAGRAM - PROCESS CONTROL

FIGURE 8

PART I - TRIAL F80-3

Trial F80-3 was a 17 day experiment, which began on March 13, 1980. This was the third and final trial of the second set of extraction trials. Data plots for the entire experiment are in Appendix C.

Choice of Injection Well

The F80-3 trial was conducted in the 300 series wells as were F80-1 and F80-2. Figure 9 shows a cross section of the three wells of most interest. The relative well locations are presented in Figure 10. The injection well for F80-3 was well 305. For F80-1 and F80-2 the injection well was 301. Well 305 was unshot (not used for explosive fracturing) and was not previously burned. Thus it was concluded that the troublesome circumstances of the previous two trials might be avoided i.e.,

a. Extreme Temperature in Injection Well Cavity

A severe flash fire was experienced during F80-1 with subsequent burn-off of the downhole equipment. An unshot well such as well 305 with low rugosity (smoother walls) would substantially reduce the intensity of such flashing because of the reduced surface area.

b. Loss of Injected Gases

Less than one-third of the injected gases were recovered during F80-2. During the burn phase of F80-2 recovery was less than ten percent. Three sizeable detonations with explosive charges in 301 apparently produced a "loose" system. There was evidence of an intricate fracture system in the well cavity and also there was known damage to the casing at the 1150 foot level. An unshot well such as 305 could reasonably be expected to show better gas containment during the burn as it always had during permeability testing.

c. Loss of Permeability

During each of the two previous trials, F80-1 and F80-2, a steady increase in resistance to gas flow developed as the burn phase progressed. After these trials it was evident that this loss of communication was the most serious obstacle to reaching the experimental goals. Choosing then for the F80-3 trial the two wells that had consistently exhibited the best communication of all wells drilled at the Sanilac site would give the most conclusive test results. Such reasoning clearly dictated that the 305-306 fracture(s) be selected. Table 2 contains a summary of well 305 to well 306 air permeability tests.

Fractures Detected in 300 Series Wells

From various logging techniques and from downhole TV camera probes (Reference 2) the primary crack configuration in the 300 series wells was determined to be as shown in Figure 9. As is characteristic of the Antrim at this depth, the fractures were oriented vertically.

ISOMETRIC VIEW SHOWING MAJOR INTERCOMMUNICATION PATHS

FIGURE 9

ARRANGEMENT OF WELLS AND RELATIVE COMMUNICATION

FIGURE 10

TABLE 2
AIR PERMEABILITY TEST AFTER F80-2
AND BEFORE F80-3 EXTRACTION TRIAL

<u>INJECTION WELL</u>		<u>PRODUCTION WELL</u>		
#305		#306		
<u>Air In</u>	<u>Pressure</u>	<u>Air Out</u>	<u>Pressure</u>	<u>Air</u>
<u>scfm</u>	<u>psig</u>	<u>scfm</u>	<u>psig</u>	<u>Recovery</u>
158	640	154	100	97.5
156	660	146	400	93.6
158	680	135	600	85.4

Downhole Equipment Arrangement

The placement of the downhole hardware is shown in Figure 11. The burner was positioned in the casing. An air flow of 40-50 scfm was maintained in the casing to prevent damage from high temperatures. Thermocouples #1 and #2 located in that air stream operated for the entire trial and indicated no significant temperature rise at that level. Thermocouple #3 failed early in the trial during a brief air/fuel upset, however, thermocouple #4 persisted to the end of the trial. T/C #4 was no doubt aided by the moderating influence of the casing air flow. Maximum temperature recorded by T/C #4 was 1175°C (2147°F).

Because of a restriction in the well casing at the 500 foot level, a finned collar for enhancing air cooling could not be installed in well 305. Such a cooling collar had been used very advantageously in well 301 for trial F80-2. This was not considered highly critical in F80-3 because the smaller diameter casing of well 305 (5.012 inches) did not provide the large back-flow area of well 301 (9.001 inches).

Ignition - F80-3

The burner flame was initiated by personnel of TOR, Inc. at 9:30 a.m. on March 13, 1980. At that time air flow to the burner was 100 scfm and air flow to the casing was 60 scfm. This was the maximum air flow recommended by TOR for the size burner (3.5 in. I.D.) used in F80-3. On four occasions between 12 and 24 hours after burner start, there were burner flameouts. Fortunately auto-ignition was easily achieved by reducing burner air flow. Burner air was permanently reduced to 85 scfm after the fourth flameout and no further problems with flame stability were encountered. Operations proceeded smoothly during the next 48 hours. T/C #4 showed a steady temperature rise in borehole temperature. No further changes in air flow rates were made until high pressure in the injection well forced flow reductions. This situation is discussed in detail in a later section of this report.

MODIFIED BURNER AND DOWNHOLE HARDWARE LOCATIONS
IN INJECTION WELL #305, F80-3

FIGURE 11

Verification of Shale Ignition - Carbon Balance

A carbon balance was determined for each day of the trial. The results are presented in Figure 12. These data show there was combustion of formation materials each day of the trial including the first day. The exact nature of the reaction under ground cannot be specified. However, a detailed carbon analysis of the data from the third day of the trial is strong evidence that the carbon source is primarily combustion of shale and pyrolysis products. The analysis is presented in Appendix B. The same analysis indicates that it is highly improbable that the source of the net carbon produced is the combustion of naturally occurring formation gas.

Borehole Burning

Figure 13 shows gas analysis from the primary production well, #306. Shown plotted are "BMIS" (Beckman Multi-Instrument System) data which were verified by data from on-line chromatography. The volume percent of O₂ and CO₂ showed several unexpected oscillations. The hot gases generated in the burner had to travel nearly 100 feet through the borehole to enter the first major fracture. Consequently, a borehole heat-up period was required before gases at shale ignition temperature (850°F) reached the fracture. Thus the steady decline in percent oxygen present with the corresponding increase in CO₂ for the first 48 hours would indicate a borehole fire.

This 48 hour period of increasing fire intensity was followed by a 12 hour period in which the fire intensity diminished as indicated by rising O₂ levels and falling CO₂ levels. This was followed by another 12 hours of fire build up. This might best be visualized as the reaction "walking" down the borehole. As one vertical section burned out, the next section heated up to ignition temperature. There was a third and final oscillation of O₂ and CO₂ levels between 72 hours and 90 hours of elapsed time.

For the next five days there was a relatively steady state period, which can be characterized as formation heat up. Analysis of the production well gases indicated that the only significant combustion was that taking place in the burner. All surfaces hot enough to react had apparently already flashed. Net carbon output slowly decreased during this steady state period.

Fracture Burning

At the 204 hour mark there was a dramatic change in process conditions. The levels of O₂, CO₂ and, 16 hours later, total hydrocarbons all indicated significant combustion had begun in addition to the burner reaction. This was interpreted as the onset of a reaction in the 305-306 fracture. The volume percent of oxygen decreased steadily until it was essentially zero after 245 hours. The volume percent of carbon dioxide moved correspondingly upward. From hour 240 to hour 264 there was one more perturbation in O₂ and CO₂ levels, the cause of which is unknown. There were no process upsets in the support systems and no significant changes in any control setting. After hour 264 oxygen practically disappeared in the production gas

FIGURE 12

CARBON IN INJECTED METHANE AND IN THE CARBON MONOXIDE,
CARBON DIOXIDE AND TOTAL HYDROCARBONS

FIGURE 13

analysis. CO₂ levels again were elevated and there was a most welcome increase in volume percent of total hydrocarbons. These are the conditions that would be most desirable to maintain. The difficulty in doing so can readily be seen in the pressure and flow plots (Figure 13).

Crack Closure - Pressure Rise Compensation

There was a steady increase in the resistance to gas flow from the injection well. It is evident this phenomenon began at light-off and continued relentlessly throughout the trial. Two methods were used to compensate for the pressure rise that resulted from this increased flow resistance. The first method called "frac tip stressing" or "gas propping" entails raising the back pressure, i.e. the pressure in the production wells. It is very clear from Figure 13 that this method was effective. For example at hour 82, a steep pressure rise in well 305 was quickly terminated by increasing the pressure in well 306 by 100 psi. At hour 228, gas propping was effectively used again. The second method used to alleviate high injection well pressures was to decrease injection gas flow rate. This was done repeatedly and the flow rate curve in Figure 14 reflects this downward drift in the rate of injection. Reducing flow to the injection well eventually led to problems in burner operation and/or maintenance. As discussed previously, approximately 50 scfm of air was supplied to the casing to moderate temperatures around the burner, gas sample line and thermocouple wires. Decreasing casing air flow led to the risk of heat damage to the downhole equipment. The other alternative, reducing air to the burner either raises the burner operating temperature or if the methane rate is correspondingly reduced, there is a net loss in energy rate supplied to the formation. At some point this input would fall behind heat losses from the combustion zone and eventually no portion of the formation would sustain a combustion.

As reference again to Figure 14 will show, both of the just described methods were used to the maximum extent.

Trial Terminated - Pressure Limits Reached

During the 11th day of the trial, at hour 256, injection well pressure reached 1300 psi. This was the practical high pressure limit of the compressors. Air and methane flows to 305 were drastically reduced and as a consequence, the burner flame went out. Over the next three days attempts to re-light the burner spontaneously by creating a variety of conditions in the injection well were all unsuccessful. This was considered to be relatively unimportant because the conclusion of the experiment was already clear;

An excellent fracture at the outset not withstanding,
introduction of high temperature gases to the fracture
leads to an ever increasing resistance to flow until
a meaningful experiment can no longer be continued.

Final Manuevers F80-3

After possibilities of a spontaneous re-light were no longer thought possible, all back pressure was removed from well 306. The result was as expected. Without gas propping and with a constant injection rate, the pressure of the injection well immediately increased. During the

FIGURE 14

remaining five days of the experiment, several modified air permeability tests were run as well as three sweat-sweep cycles, a technique designed to increase the btu content of the production gas. The results of these tests were partially obscured by the changing conditions during the cool-down of the formation. Quantities of slightly improved gas were recovered. The results of the air permeability tests are not directly comparable to pre F80-3 tests for the reason stated above. However it was evident that the formation was opening up and approaching preburn conditions. For example, with a steady 300 psi differential pressure between injection well 305 and production well 306, flow from well 306 increased 50 percent in 20 hours. Flow was 30 scfm at hour 412 and 45 scfm at hour 432 with all other wells shut-in.

Data Interpretation - Time Lag

When comparing production well gas analysis as shown in Figure 13 and injection well conditions as in Figure 14, a time lag must be considered. There is a well transport time of one to two hours and an analytical delay of approximately one hour. Additionally there was a lag due to formation flow time. Total lag times have been determined to be between three and seven hours (see Figure 15). Only the injection well outfitted with a special downhole sample line had a response time in the one to two minute range.

Production Gas Quality F80-3

The energy content of production gases remained low for the entire trial period (Figure 16). For the first ten days of the trial, 3 btu/scf was a typical average. Until oxygen levels were down to less than 1% by volume, pyrolysis products were consumed in the formation. Gas quality still was low, only averaging 25-30 btu/scf when oxygen was practically absent in the production gases. While this does not approach any level of commercial interest, the following should be considered;

1. In terms of the planned extraction operations, F80-3 was still in the ignition stage.
2. After combustion was well established, several strategies for improving gas quality could have been tried.
 - a. Preserve Pyrolysis Products by establishing a separate pyrolysis front. Several techniques for establishing separate fronts have been advanced in the literature. All have as the ultimate goal the removal of the pyrolysis products without subjecting them to oxygen exposure.
 - b. Cyclic Operations such as a sweat period with no injected gases followed by a sweep with inert gas. A cyclic operation used advantageously during the 1978 trials (Reference 1) was alternate air injection and venting from the injection well (Huff and Puff).
 - c. Oxygen Enriched Injection Gas This approach saves energy used for compressing inert gas and prevents nitrogen dilution of production gases.

EFFECT OF NITROGEN INJECTION IN WELL 301
ON OXYGEN CONCENTRATION AT WELL 305

FIGURE 15

FIGURE 16

Mass and Energy Balance F80-3

Overall, 78.3 percent of the injected gas was recovered. The energy expended to supply the compressed air and methane measured by the fuel input to diesel engines was 286×10^6 btu or about 80 percent of all energy used in F80-3. Table 3 summarizes the results of the energy balance. A print-out of the results of the day by day energy balance calculations are in Appendix A.

Total methane volume delivered to the burner during trial F80-3 was 67,500 scf. If combustion was complete, energy from the methane fuel was 68×10^6 btu or slightly less than 20 percent of the total energy input.

PART II - CONCLUSIONS

1. Demonstrated during these trials were improved procedures, techniques and systems which made the following activities routinely safe and efficient.
 - a. Positively ignite shale at 1200 feet below surface.
 - b. Maintain a burner for reignition with positive flame detection.
 - c. Produce a pyrolysis/gasification of the organic content of the shale.
 - d. Maintain a continuous product gas analysis and provide a daily mass and energy balance.
 - e. Maintain a brine-free formation.
2. There is an ever increasing resistance to gas flow during a burn. Although the 300 series wells initially showed good communication, the permeability was in the form of discrete fractures estimated to average about 1-2 mm wide and yielding less than 1% void space (Reference 2). Therefore, the most likely cause of increasing flow resistance was crack closure from thermal expansion of the shale (Reference 7). Unless substantially more void space can be generated, there is essentially no probability that a successful in situ thermal method of energy extraction can be sustained in the Antrim.
3. While only gas with low energy content was produced, these trials do not establish that gas with high energy content was not achievable. The thermal pinch prevented exploration of this matter.

TABLE 3

SUMMATION OF ENERGY TOTALS

(All energy values in millions of BTU unless noted otherwise)

<u>Energy In</u>	<u>F80-2 (case 1) w/sweat cycle</u>	<u>F80-2 (case 2 w/o sweat cycle & 19.2% efficiency</u>	<u>F80-3</u>
•Compressor	1287	247	286
•Methane	409	79	68
•Total	1696	326	354
<u>Energy Out</u>			
•Expander (fuel equivalent)	77	63	111
•Gas (heating value)	63	17	10
•% Recovered	8	24	34
•Act avg GHV (BTU/SCF)	18	6	5
•Breakeven GHV (BTU/SCF)	459	96	116

PART III - Trial F80-2

Trial F80-2 was a 60 day experiment which used well 301 as the injection well and 305 as the primary production well. The significant difference between F80-2 and F80-1 was the technique used in F80-2 to protect the downhole equipment. This technique is described later in this report and in detail in Reference 3.

Almost all data collected during trial F80-2 can be found plotted in Appendix D.

Loss Of Injected Gas

Trial F80-2 was characterized by low recovery of injected gases. Figure 17 A shows that recovery at the time of burner ignition was 60 percent but dropped rapidly during the first 24 hours to 20 percent of injected gases. This was followed by 48 hours with 40 percent recovery but thereafter there was a general decline. During the period December 16 thru January 10, recovery was 10 percent or less (Figures 18 and 19). That period, 26 days, constitutes nearly one half of the total trial time. Exclusive of the post-burn experiments, overall recovery for F80-2 was 20 percent. It is enlightening to note what occurred to recovery rate after periods of formation cooling. For example, during the week of January 3, the percent O_2 was rising and the percent CO_2 was declining and methane flow was zero. On the 10th of January there was a 300 percent increase in the recovery rate from 9 to 27 percent.

One apparent reason for losing 90 percent of the injected gases during the burn phase of the run was not identified until bleed down. Bleed down of well 301 began on January 25 and the rate of flow is shown in Figure 20 to the time where all wells were opened in preparation for the next trial. Figure 21 A shows the composition of the gases entering the bottom of well 301 casing during bleed down. Figure 21 B shows the vent gas composition at the wellhead. The gases flowing back into the casing from the Antrim formation were high in methane and contained no oxygen. This indicated that appreciable retorting may have been occurring in the Antrim shale formation even though the retort products were not recovered during the forward burn.

The vent gas composition at the wellhead indicates there was considerable dilution somewhere in the casing. Calculations showed that up to 90 percent of the vent gas could have had a composition near that of the initial air/methane mixture injected during the burn phase. This evidence of injected gas leaking through a break in the casing and flowing into strata not in contact with the burning methane helps to account for the low recovery.

Furthermore, a comparison of the proportions of C_1 's through C_4 's in the chromatographic analysis of the gas from below the casing and the wellhead vent gas showed that the hydrocarbons in the wellhead could have come from a complex gas like the below-casing sample, diluted with methane.

A - November 23-December 3

B - December 3-December 12

FIGURE 17

DATA FROM THE INJECTION WELL, #301, DURING STARTUP AND
FOR THE INITIAL OPERATING PERIOD OF EXTRACTION TRIAL F80-2

EXTRACTION TRIAL F80-2
INJECTION WELL - NO. 301

FIGURE 18

DATA FROM INJECTION AND PRODUCTION WELLS, EARLY JANUARY

FIGURE 19

EXTRACTION TRIAL F80-2 PRESSURES AND FLOWS BEFORE AND DURING BLEED DOWN

FIGURE 20

"A"

"B"

WELL #301 VENT GAS COMPOSITION BELOW
THE CASING AND AT THE WELLHEAD

FIGURE 21

Another factor to consider at this point is the possibility of condensing some of the components of the effluent gas. This effect would be more pronounced in the gases vented from the wellhead and may account for some of the difference in composition between that gas and the gas vented through the high volume sample line. The high velocity in the sample line makes entrainment of condensate possible.

Burner Maintenance

A major achievement of F80-2 was the successful maintenance of the burner and other downhole equipment. Figure 22 depicts how equipment was positioned especially the deployment of the finned collar. By blocking the casing between the burner and the well cavity and also by providing additional heat transfer area for casing cooling air, the collar helped maintain the integrity of the equipment above it. For the first time in Antrim extraction trials, reignition of the burner was possible. A total of five burner ignitions were made during F80-2, the last being 13 days into the run. There is evidence of good burner operation after 30 days of the experiment. It is reasonable to assume reignitions would have been possible at least to that point.

Shale Ignition - F80-2

Operation of the burner prior to shale ignition was conservative after the firestorm experience of F80-1. Air/methane ratio was not allowed to go below 30 during the 12 days between burner light-off and shale ignition on 12/10/79. During this period the effects of the thermal pinch were already seen. Injection pressure had to rise 50 percent, from 600 psi to 900 psi to maintain a steady air injection rate of 200 scfm.

Figure 23 shows the way shale ignition is reflected in the well 305 production gas analysis. For the same reasons presented in the discussion of F80-3, the period from 12/10/79 to 12/19/79 is interpreted as primarily a time of combustion in the injection well cavity.

Burning in Fracture F80-2

The period from 12/19/79 to 12/26/79 was a period of relatively smooth operation. More steady thermocouple readings indicated the site of shale combustion had moved from the cavity to the fracture. Oxygen levels in the production gases fluctuated between 5 and 12 percent. Recovery of injected gases was now under 10 percent.

Burner Out-Shale Combustion Continues

On 12/26/79 the burner flame went out. Methane feed was continued. Rather surprisingly the oxygen level in the production gas went down to one percent and all other process conditions became very steady (Figure 24). This condition was maintained until 1/3/80. It was concluded that with methane addition and with a well established combustion the situation was stable and unlikely to change in a reasonable time. Consequently methane feed was terminated. The combustion proved not to be self sustaining and by 1/9/80 the production gas analysis showed that the fire was out. This is readily apparent in Figure 18.

POSITION OF EQUIPMENT DURING
EXTRACTION TRIAL F80-2

FIGURE 22

EXTRACTION TRIAL F80-2
PRODUCTION WELL - No. 305

FIGURE 23

EXTRACTION TRIAL F80-2
PRODUCTION WELL - No. 305

FIGURE 24

EXTRACTION TRIAL F80-2
PRODUCTION WELL - NO. 305

FIGURE 25

Auto Reignition Attempted

Methane feed was restarted on 1/11/80 and continued for 12 days. There were no indications of combustion becoming re-established (Figures 25 and 26).

F80-2 Shutdown

The wells were closed in on 1/22/80 and pressures in all wells were monitored closely as conditions moved towards equilibrium. Results of this experiment and of the subsequent bleeddown beginning on 1/25/80 have been described above under, Loss Of Injected Gas.

FIGURE 25

EXTRACTION TRIAL F80-2
INJECTION WELL - NO. 301

FIGURE 26

Mass And Energy Balance F80-2

Overall only 25 percent of the injected gases were recovered. The energy for compression of air and methane was 1287×10^6 btu or about 76 percent of all energy used in F80-2. Energy summations for F80-2 are in Table 3. A computer print-out of the day by day energy balance calculations are in Appendix A.

Methane delivered to the burner during trial F80-2 was 397,000 scf. Assuming complete combustion, energy from methane was 409×10^6 btu or 24 percent of the total energy input.

The category labeled "expander energy" is the amount of energy retrievable from the production gases let down through a turbine device. State-of-the-art efficiencies are assumed.

Breakeven GHV is, as the name suggests, the gross heating value of the recovered gas that would have given 100 percent energy recovery.

Comparison F80-2 And F80-3

To facilitate a better comparison between F80-2 and F80-3, Table 3 includes case 2 for run F80-2. Case 2 data is adjusted to compensate for the gas loss experienced during F80-2. Also case 2 is adjusted for the sweat period of F80-2 which was not run in F80-3. Case 2, F80-2, then is F80-2 case 1 (as run data) with the effects of the two factors, gas leakage and post sweat cycle, washed out. What is revealed by this maneuver is surprising. First total "energy in" are comparable. That is to say that the total energy actually affecting the Antrim formation was about the same for the two trials. Secondly the percent of energy recovered are comparable, 24 percent for F80-2 and 34 percent for F80-3. One conclusion that can be drawn is that in terms of energy and impact on the Antrim formation, F80-2 and F80-3 are similar experiments. The longer elapsed time of F80-2 is attributable to the "relief value effect" of the "loose" formation.

A second conclusion is the concept of a "natural flow level" for a fracture. During F80-2 conditions had reached a steady state condition from 12/26/79 to 1/3/80. Approximately 10 scfm flowed through the Antrim. This was air enriched with methane which passed through a combustion zone where oxygen was depleted to one percent. The heat generated by this flow just balanced heat transfer away from the combustion zone. More flow produced a hotter fire, a hotter formation and more thermal pinch. Less flow produced a slower reaction, a cooler formation and a fracture opening. Thus the "natural flow level" for the 301-305 fracture appears to be 10 scfm. All other flow was channeled elsewhere in the formation. With a "tight" formation as in the case of F80-3, the flow is not able to seek the natural level. All flow is forced through the fracture. The combustion becomes very intense until the thermal pinch sends the injection pressure to the upper limit of the compressors.

PART IV - Trial F80-1

F80-1 was a short experiment of only seven days. It was the first extraction trial in the 300 series wells and began on October 14, 1980. Appendix E contains many additional plots of data which in most cases are not included in this text section.

Figure 27 shows how the burner, thermocouples and exhaust sample line were positioned in well 301 with respect to the casing and cavity. The position was determined by the location of the main fracture leading to well 305 the primary production well. It was thought that this would allow the exhaust gases from the burner to enter the crack at near their maximum temperature.

Burner Light-Off

The burner was ignited and the temperature was incrementally increased towards a target of 1400° F. Thirty hours after burner ignition, the temperature recorded on the tailpipe was 825° F. Methane flow was then increased so the air/methane ratio dropped from 44:1 to 35:1.

Firestorm In Injection Well Cavity

At the 45 hour mark the thermocouples located in well 301 cavity recorded a dramatic surge upwards. The last recorded temperature before thermocouple failure was 1650° F. Figure 28 shows the nearly instantaneous temperature rise from 700° to 1650°F. During this period there was a rapid drop, from 15 to 3 percent in the oxygen concentration in the effluent gas from production well 305. This and the corresponding increase in carbon dioxide concentration are shown in Figure 29.

POSITION OF EQUIPMENT DURING
EXTRACTION TRIAL F80-1

FIGURE 27

FIGURE 28

IGNITION WELL TEMPERATURE INCREASE
ON IGNITION OF SHALE IN EXTRACTION TRIAL F80-1

CONCENTRATION OF OXYGEN AND CARBON DIOXIDE
IN EFFLUENT GASES FROM PRODUCTION WELL #305,
EXTRACTION TRIAL F80-1

FIGURE 29

Shale Ignition F80-1

The oxygen concentration at production well 305 decreased to about 3 percent at the 50 hour point and remained there until hour 86, indicating good combustion of the shale.

Recovery Of Injected Gases F80-1

After shale ignition was indicated, recovery rate fell to less than 50 percent. Reducing injection air from 200 scfm to 100 scfm seemed to only have one effect and that was to extinguish the shale fire, or at the least shorten the time to the fire-out condition. Oxygen in the production gas increased at hour 86 to 16 percent.

Termination Of Run F80-1

After the fire storm, the burner exhaust gas sampler plugged. With the thermocouples also inoperative, there was no positive way of determining that the methane was burning at the burner. The electronic pressure sensor for flame detection as described in Reference 5 had not as yet been installed. There was now no safe method of adding heat to the formation so the trial was terminated. Most of the downhole equipment that had been in the cavity was never retrieved. Only the 1 inch methane line was intact. The burned-off ends of the 316 stainless steel parts showed stress corrosion cracking. High temperature oxidation of Inconel* 600 and carbon steel was very evident (Reference 3). Even Hastelloy** C-276 did not endure the very severe environment, and this had been considered the alloy best suited for downhole conditions.

Permeability F80-1

Permeability data from before F80-1 showed an average recovery of 85 percent of injected gases. The recovery rate for all of F80-1 was 50 percent with a low of 25 percent during the fire storm (Figure 30). Permeability during F80-2 before light-off of burner was 73 percent. It appears that permeability in 300 series wells decreased approximately 10 percent as a consequence of F80-1.

Conclusions F80-1

1. The burner touched off a very hot fire ($>2500^{\circ}$ F) in the well cavity. The burner, sample lines and thermocouples did not survive the exposure to the severe conditions. For any trial of significant duration, methods must be devised to protect downhole equipment. In F80-1 there was insufficient burner-on time to obtain and evaluate gas production from the shale.
2. The recovery of injected gas was low.
3. Shale combustion was maintained for 48 hours.

* Trademark of Huntington Alloys, International Nickel Company.

** Trademark of Stellite Division, Cabot Corporation.

FIGURE 30

REFERENCES

1. McNamara, P. H., "Energy From True In Situ Processing of Antrim Oil Shale-Initial In Situ Extraction Trials" Topical Report FE-2346-42.
2. Peil, C. A., "Energy From True In Situ Processing of Antrim Oil Shale - Preparation of an In Situ Retort Bed by Explosive Underreaming and Fracturing" Topical Report FE-2346-67.
3. VanDerPloeg, M. L., Pihlaja, R. K., "Energy From True In Situ Processing of Antrim Shale - TOR Methane Burner Ignition System" Topical Report FE-2346-76.
4. Pihlaja, R. K., "Energy From True In Situ Processing of Antrim Shale - Sampling and Analytical Systems" Topical Report FE-2346-75.
5. Frost, J. R., Pihlaja, R. K., "Energy From True In Situ Processing of Antrim Shale - Process Control and Data Collection" Topical Report FE-2346-70.
6. Murdick, D. A., "Energy From The In Situ Processing of Antrim Shale - Process Equipment Used in the Extraction Trials" Topical Report FE-2346-74.
7. Hockings, W. A., "Physical Properties of Antrim Shale" Topical Report FE-2346-85.
8. Allred, V. D., "Some Characteristic Properties of Colorado Oil Shale Which May Influence In Situ Processing" Oil Shale Symposium, April 30, 1964, Golden, Colorado.

APPENDIX A

Tabulation of daily mass & energy data . . .	F80-3
Tabulation of daily mass & energy data . . .	F80-2
Tabulation of daily mass & energy data . . . without bleedback and at 19.2% input efficiency	F80-2

RKPME2 08:35 17-Jul-80
INPUT AMBIENT TEMP (DEG F),BAROMETRIC PRESSURE (PSIA)
? 40,14.6
INPUT INITIAL FILE NAME (MAR73.DAT)
? MAR73.DAT
INPUT FINAL FILE NAME
? MAR91.DAT
INPUT JULIAN DAY,TIME OF BLEEDBACK START
,JULIAN DAY,TIME OF BLEEDBACK STOP
? 92,0,92,24

ENERGY BALANCE
FILES MAR73.DAT TO MAR91.DAT

CALCULATED OVERALL FIELD CONDITIONS

TIME WTD AVG BURNER DUTY FACTOR: .705154
FLOW WTD AVG BURNER (AIR/FUEL): 33.5098
FLOW WTD AVG INJECTION PRESSURE: 1023.54 PSIG
OVERALL FLOW WTD AVG APPARENT RECOVERY: 78.2618 %
FLOW WTD AVG (PRODUCTION PSIG/INJECTION PSIG): .742791

ENERGY INPUTS

AMBIENT TEMP: 40 F
BAROMETRIC PRESSURE: 14.6 PSIA

FILE NAME	EQUIVALENT FUEL BTU'S TO DRIVE COMPRESSOR ENGINES		BTU'S CHEMICAL ENERGY	TOTAL INPUT ENERGY
	AIR + N2	METHANE		
MAR73.DAT	.206559E 8	176796	.283702E 7	.236697E 8
MAR74.DAT	.200372E 8	337120	.506461E 7	.254389E 8
MAR75.DAT	.200588E 8	351967	.534949E 7	.257602E 8
MAR76.DAT	.206776E 8	435920	.61958E 7	.273093E 8
MAR77.DAT	.205466E 8	432993	.605225E 7	.270319E 8
MAR78.DAT	.199141E 8	430151	.599596E 7	.263402E 8
MAR79.DAT	.192732E 8	432752	.600335E 7	.257093E 8
MAR80.DAT	.186559E 8	421919	.584025E 7	.249181E 8
MAR81.DAT	.176764E 8	417449	.575996E 7	.238538E 8
MAR82.DAT	.156032E 8	273744	.374518E 7	.196221E 8
MAR83.DAT	.137174E 8	291570	.396808E 7	.17977E 8
MAR84.DAT	.874572E 7	164809	.231262E 7	.112232E 8
MAR85.DAT	.114962E 8	240218	.339312E 7	.151295E 8
MAR86.DAT	.122409E 8	279662	.385355E 7	.163741E 8
MAR87.DAT	.615721E 7	147973	.200443E 7	.830961E 7
MAR88.DAT	.355862E 7	0	0	.355862E 7
MAR89.DAT	.860196E 7	0	0	.860196E 7
MAR90.DAT	.154093E 8	0	0	.154093E 8
MAR91.DAT	.814346E 7	0	0	.814346E 7
TOTAL	.281169E 9	.483504E 7	.683757E 8	.35438E 9
AVERAGE	.147984E 8	254476	.359872E 7	.186516E 8
TOTAL EQUIV				
GAL #2 DF	2028.36	34.8801	493.264	2556.51

ENERGY OUTPUTS

FILE NAME	EQUIVALENT FUEL BTU'S EXPANDER ENERGY		BTU'S CHEMICAL ENERGY	TOTAL OUTPUT ENERGY	NET ENERGY
MAR73.DAT	.713357E 7	.129616E 7	.842973E 7	.152399E 8	
MAR74.DAT	.906629E 7	340337	.940663E 7	.160323E 8	
MAR75.DAT	.984412E 7	286694	.101308E 8	.156294E 8	
MAR76.DAT	.85912E 7	490950	.908215E 7	.182272E 8	
MAR77.DAT	.108778E 8	549860	.114276E 8	.156042E 8	
MAR78.DAT	.104783E 8	489899	.109682E 8	.15372E 8	
MAR79.DAT	.972641E 7	409875	.101363E 8	.15573E 8	
MAR80.DAT	.895568E 7	354522	.93102E 7	.156079E 8	
MAR81.DAT	.759219E 7	284892	.787708E 7	.159767E 8	
MAR82.DAT	.540815E 7	377977	.578612E 7	.13836E 8	
MAR83.DAT	.397336E 7	415497	.438885E 7	.135882E 8	
MAR84.DAT	.14532E 7	.100369E 7	.245689E 7	.876626E 7	
MAR85.DAT	.264178E 7	.100597E 7	.364775E 7	.114818E 8	
MAR86.DAT	.323231E 7	845407	.407772E 7	.122963E 8	
MAR87.DAT	983598	290068	.127367E 7	.703595E 7	
MAR88.DAT	510063	288581	798644	.275997E 7	
MAR89.DAT	.191359E 7	591504	.25051E 7	.609686E 7	
MAR90.DAT	.425936E 7	108183	.436755E 7	.110418E 8	
MAR91.DAT	.41133E 7	154042	.426734E 7	.387612E 7	
TOTAL	.110754E 9	.958411E 7	.120338E 9	.234042E 9	
AVERAGE	.582917E 7	504427	.63336E 7	.12318E 8	
TOTAL EQUIV					
GAL #2 DF	798.984	69.14	868.124	1688.38	

AVG ENERGY RECOVERY: 33.9574 %
 TOTAL RECOVERED GAS: .209378E 7 SCF
 ACTUAL AVG GHV: 4.57305 BTU/SCF
 BREAK-EVEN GHV: 116.246 BTU/SCF

Stop at line 31190

Ready

RUN
RKPM9 13:40 17-JUL-80
INPUT AMBIENT TEMP (DEG F), BAROMETRIC PRESSURE (PSIA)
? 40,14.6
INPUT INITIAL FILE NAME (MAR73.DAT)
? NOV330.DAT
INPUT FINAL FILE NAME
? NOV22.DAT
INPUT INJECTION EFFICIENCY (%)
? 19.227
INPUT JULIAN DAY, TIME OF BLEEDBACK START
JULIAN DAY, TIME OF BLEEDBACK STOP
? 25,17,43,24

FIELD DATA AT 19.227 % INPUT EFFICIENCY & WITHOUT BLEEDBACK

ENERGY BALANCE
FILES NOV330.DAT TO NOV22.DAT

CALCULATED OVERALL FIELD CONDITIONS

TIME WTD AVG BURNER DUTY FACTOR: .793894
FLOW WTD AVG BURNER (AIR/FUEL): 28.6333
FLOW WTD AVG INJECTION PRESSURE: 942.982 PSIG
OVERALL FLOW WTD AVG APPARENT RECOVERY: 99.9993 %
FLOW WTD AVG (PRODUCTION PSIG/INJECTION PSIG): .150946

ENERGY INPUTS

AMBIENT TEMP: 40 F
BAROMETRIC PRESSURE: 14.6 PSIA

FIELD DATA AT 19.227 % INPUT EFFICIENCY & WITHOUT BLEEDBACK

FILE NAME	EQUIVALENT FUEL BTU'S TO DRIVE COMPRESSOR ENGINES		BTU'S CHEMICAL ENERGY	TOTAL INPUT ENERGY
	AIR + N2	METHANE		
NOV330.DAT	.464376E 7	25895.3	444947	.51146E 7
NOV331.DAT	.443312E 7	23441.2	400632	.48572E 7
NOV332.DAT	.46708E 7	68721.3	.117816E 7	.591768E 7
NOV333.DAT	.508596E 7	77288.7	.124974E 7	.6413E 7
NOV334.DAT	.50163E 7	94602.6	.146488E 7	.657579E 7
NOV335.DAT	.51154E 7	97247.5	.147271E 7	.668536E 7
NOV336.DAT	.51982E 7	109448	.164612E 7	.695376E 7
NOV337.DAT	.473671E 7	26371.7	398760	.516184E 7
NOV338.DAT	.516998E 7	59514.2	891107	.612061E 7
NOV339.DAT	.520298E 7	120649	.178026E 7	.710389E 7
NOV340.DAT	.519893E 7	122158	.179927E 7	.712036E 7
NOV341.DAT	.521181E 7	47858.4	703667	.596333E 7
NOV342.DAT	.498457E 7	66999.9	988695	.604027E 7
NOV343.DAT	.432784E 7	30064.8	447809	.480572E 7
NOV344.DAT	.487521E 7	72259.4	.107103E 7	.601849E 7
NOV345.DAT	.489751E 7	146987	.214121E 7	.718571E 7
NOV346.DAT	.502549E 7	148771	.214602E 7	.732028E 7
NOV347.DAT	.503538E 7	151961	.21721E 7	.735944E 7
NOV348.DAT	.502362E 7	150264	.214675E 7	.732063E 7
NOV349.DAT	.492003E 7	150538	.214587E 7	.721644E 7
NOV350.DAT	.480149E 7	146864	.209461E 7	.704297E 7
NOV351.DAT	.471652E 7	143877	.203856E 7	.689895E 7
NOV352.DAT	.453149E 7	101915	.144013E 7	.607353E 7
NOV353.DAT	.416786E 7	139956	.199919E 7	.630701E 7
NOV354.DAT	.366167E 7	109217	.162252E 7	.539341E 7
NOV355.DAT	.363951E 7	107244	.159288E 7	.533964E 7
NOV356.DAT	.364724E 7	94728.1	.140176E 7	.514372E 7
NOV357.DAT	.363372E 7	92621.9	.136374E 7	.509008E 7
NOV358.DAT	.363089E 7	97091.5	.141213E 7	.514012E 7
NOV359.DAT	.363044E 7	97316.4	.141389E 7	.514165E 7
NOV360.DAT	.363607E 7	108726	.157409E 7	.531888E 7
NOV361.DAT	.365584E 7	108359	.156998E 7	.533418E 7
NOV362.DAT	.363416E 7	100245	.145816E 7	.519257E 7
NOV363.DAT	.363644E 7	79743.8	.1163E 7	.487918E 7
NOV364.DAT	.369911E 7	82069.6	.119649E 7	.497767E 7
NOV365.DAT	.368065E 7	83147.5	.122195E 7	.498576E 7
NOV1.DAT	.368722E 7	82431.1	.119811E 7	.496776E 7
NOV2.DAT	.364695E 7	85264.9	.123432E 7	.496654E 7
NOV3.DAT	.363797E 7	64027.6	920579	.462264E 7
NOV4.DAT	.364835E 7	0	0	.364835E 7
NOV5.DAT	.366203E 7	0	0	.366203E 7
NOV6.DAT	.3654E 7	0	0	.3654E 7
NOV7.DAT	.364193E 7	0	0	.364193E 7
NOV8.DAT	.358945E 7	0	0	.358945E 7
NOV9.DAT	.362306E 7	0	0	.362306E 7
NOV10.DAT	.367963E 7	65250	918244	.466313E 7
NOV11.DAT	.370078E 7	108304	.152316E 7	.533224E 7
NOV12.DAT	.364306E 7	101539	.14309E 7	.51755E 7
NOV13.DAT	.343363E 7	106126	.150567E 7	.504543E 7
NOV14.DAT	.34054E 7	99357.4	.14091E 7	.491386E 7
NOV15.DAT	.339154E 7	109160	.154426E 7	.504496E 7
NOV16.DAT	.33791E 7	123860	.177164E 7	.527461E 7
NOV17.DAT	.375096E 7	129746	.198175E 7	.586146E 7
NOV18.DAT	.448605E 7	173323	.269247E 7	.735684E 7
NOV19.DAT	.460057E 7	197217	.291824E 7	.771602E 7
NOV20.DAT	.459718E 7	190265	.278752E 7	.757496E 7
NOV21.DAT	.451337E 7	177471	.257039E 7	.726173E 7
NOV22.DAT	.193977E 7	65990.2	957297	.296246E 7
TOTAL	.242039E 9	.536696E 7	.78617E 8	.326073E 9
AVERAGE	.417394E 7	92533.7	.135546E 7	.562194E 7
TOTAL EQUIV GAL #2 DF	1746.43	38.7174	567.145	2352.3

FIELD DATA AT 19.227 % INPUT EFFICIENCY & WITHOUT BLEEDBACK

ENERGY OUTPUTS

FILE NAME	EQUIVALENT FUEL BTU'S EXPANDER ENERGY	BTU'S CHEMICAL ENERGY	TOTAL OUTPUT ENERGY	NET ENERGY
NOV330.DAT	.401996E 7	287294	.430726E 7	307343
NOV331.DAT	.45183E 7	66606	.458491E 7	272286
NOV332.DAT	.205731E 7	64414.9	.212173E 7	.379595E 7
NOV333.DAT	.260684E 7	296157	.2903E 7	.351E 7
NOV334.DAT	.339239E 7	483436	.387586E 7	.269992E 7
NOV335.DAT	.385181E 7	445631	.429724E 7	.238813E 7
NOV336.DAT	.277018E 7	450353	.322054E 7	.373323E 7
NOV337.DAT	.191271E 7	728297	.264101E 7	.252093E 7
NOV338.DAT	.269077E 7	552037	.32328E 7	.28878E 7
NOV339.DAT	.190717E 7	317443	.222461E 7	.487928E 7
NOV340.DAT	.175083E 7	310701	.206153E 7	.505882E 7
NOV341.DAT	.20243E 7	620968	.264527E 7	.331807E 7
NOV342.DAT	.144746E 7	347221	.179468E 7	.424559E 7
NOV343.DAT	.156497E 7	929383	.249435E 7	.231136E 7
NOV344.DAT	.222422E 7	422996	.264722E 7	.337127E 7
NOV345.DAT	.150904E 7	334566	.184361E 7	.53421E 7
NOV346.DAT	.155126E 7	693255	.224451E 7	.507577E 7
NOV347.DAT	.110747E 7	362344	.146981E 7	.588962E 7
NOV348.DAT	.10188E 7	413862	.143266E 7	.588796E 7
NOV349.DAT	.110419E 7	324365	.142856E 7	.578738E 7
NOV350.DAT	882997	198302	.10813E 7	.596167E 7
NOV351.DAT	618096	232138	850234	.604872E 7
NOV352.DAT	552941	226232	779174	.529436E 7
NOV353.DAT	532262	226987	759248	.554776E 7
NOV354.DAT	439806	282932	722739	.467067E 7
NOV355.DAT	500412	241762	742174	.459746E 7
NOV356.DAT	503405	109407	616811	.452691E 7
NOV357.DAT	497805	206727	704532	.433554E 7
NOV358.DAT	493363	259601	752964	.438715E 7
NOV359.DAT	429329	225034	654363	.448728E 7
NOV360.DAT	391617	204134	595751	.472313E 7
NOV361.DAT	209045	274485	483530	.485065E 7
NOV362.DAT	200207	382739	582947	.460962E 7
NOV363.DAT	193320	303911	502232	.437635E 7
NOV364.DAT	228554	338704	567258	.441041E 7
NOV365.DAT	236622	314112	550734	.443502E 7
NOV1.DAT	215374	248743	464117	.450364E 7
NOV2.DAT	320657	247152	467809	.449873E 7
NOV3.DAT	187780	183962	371742	.42509E 7
NOV4.DAT	189356	161191	350547	.32978E 7
NOV5.DAT	176680	139474	316134	.33459E 7
NOV6.DAT	253678	152889	406567	.324743E 7
NOV7.DAT	270523	110405	380928	.3261E 7
NOV8.DAT	241494	119283	360777	.322868E 7
NOV9.DAT	295126	128469	423596	.319947E 7
NOV10.DAT	534763	152925	687688	.397544E 7
NOV11.DAT	902301	210885	.111319E 7	.421906E 7
NOV12.DAT	923486	247980	.117147E 7	.400403E 7
NOV13.DAT	927140	257832	.118497E 7	.386046E 7
NOV14.DAT	914354	224096	.113845E 7	.377541E 7
NOV15.DAT	933041	227578	.116062E 7	.388434E 7
NOV16.DAT	981249	185564	.106681E 7	.420779E 7
NOV17.DAT	462213	227034	689246	.517221E 7
NOV18.DAT	423367	218426	641794	.671505E 7
NOV19.DAT	475432	177681	653113	.706291E 7
NOV20.DAT	527275	193514	720789	.635417E 7
NOV21.DAT	634729	430712	.106544E 7	.619629E 7
NOV22.DAT	303668	191296	494965	.246749E 7
TOTAL	.628332E 8	.169147E 8	.797479E 8	.246325E 9
AVERAGE	.108333E 7	291632	.137496E 7	.424698E 7
TOTAL EQUIV GAL #2 DF	453.281	122.023	575.304	1776.99

AVG ENERGY RECOVERY: 24.4571 %
 TOTAL RECOVERED GAS: .273719E 7 SCF
 ACTUAL AVG GHV: 6.17957 BTU/SCF
 BREAK-EVEN GHV: 96.1714 BTU/SCF

STOP AT LINE 31190

READY

RUN
RKPM2 15:47 17-JUL-80
INPUT AMBIENT TEMP (DEG F), BAROMETRIC PRESSURE (PSIA)
? 40, 14.6
INPUT INITIAL FILE NAME (MAR73.DAT)
? NOV330.DAT
INPUT FINAL FILE NAME
? NOV43.DAT
INPUT JULIAN DAY, TIME OF BLEEDBACK START
JULIAN DAY, TIME OF BLEEDBACK STOP
? 25, 17.43, 24

ACTUAL FIELD DATA INCLUDING BLEEDBACK.

ENERGY BALANCE
FILES NOV330.DAT TO NOV43.DAT

CALCULATED OVERALL FIELD CONDITIONS

TIME WTD AVG BURNER DUTY FACTOR: .582859
FLOW WTD AVG BURNER (AIR/FUEL): 28.6333
FLOW WTD AVG INJECTION PRESSURE: 942.982 PSIG
OVERALL FLOW WTD AVG APPARENT RECOVERY: 24.7618 %
FLOW WTD AVG (PRODUCTION PSIG/INJECTION PSIG): .144943

ENERGY INPUTS

AMBIENT TEMP: 40 F
BAROMETRIC PRESSURE: 14.6 PSIA

ENERGY OUTPUTS

ACTUAL FIELD DATA INCLUDING BLEEDBACK

FILE NAME	EQUIVALENT FUEL BTU'S EXPANDER ENERGY	BTU'S CHEMICAL ENERGY	TOTAL OUTPUT ENERGY	NET ENERGY
NOV330.DAT	.401996E 7	287294	.430726E 7	.222939E 8
NOV331.DAT	.45183E 7	66606	.458491E 7	.206775E 8
NOV332.DAT	.205731E 7	64414.9	.212173E 7	.286562E 8
NOV333.DAT	.260684E 7	296157	.2903E 7	.304511E 8
NOV334.DAT	.339238E 7	483486	.387586E 7	.303249E 8
NOV335.DAT	.385161E 7	445631	.429724E 7	.304735E 8
NOV336.DAT	.277018E 7	450353	.322094E 7	.329461E 8
NOV337.DAT	.191271E 7	728297	.264101E 7	.242058E 8
NOV338.DAT	.368077E 7	552037	.32328E 7	.286006E 8
NOV339.DAT	.190717E 7	317443	.222461E 7	.347229E 8
NOV340.DAT	.175083E 7	310701	.206153E 7	.349716E 8
NOV341.DAT	.20243E 7	620968	.264527E 7	.283701E 8
NOV342.DAT	.144746E 7	347221	.179468E 7	.296209E 8
NOV343.DAT	.156497E 7	929393	.249435E 7	.225003E 8
NOV344.DAT	.222422E 7	422996	.264722E 7	.288551E 8
NOV345.DAT	.150904E 7	334566	.184361E 7	.355294E 8
NOV346.DAT	.155126E 7	693255	.224451E 7	.358284E 8
NOV347.DAT	.110747E 7	362344	.146981E 7	.368068E 8
NOV348.DAT	.10138E 7	413862	.143266E 7	.366421E 8
NOV349.DAT	.110419E 7	324365	.142956E 7	.361043E 8
NOV350.DAT	.382997	198302	.10813E 7	.355493E 8
NOV351.DAT	.618096	232139	.350234	.350314E 8
NOV352.DAT	.552941	226232	.779174	.308094E 8
NOV353.DAT	.532262	226997	.759248	.320436E 8
NOV354.DAT	.439806	282932	.722739	.273285E 8
NOV355.DAT	.500412	241762	.742174	.270294E 8
NOV356.DAT	.508405	108407	.616811	.261358E 8
NOV357.DAT	.497805	206727	.704532	.257691E 8
NOV358.DAT	.493363	259601	.752964	.259809E 8
NOV359.DAT	.429329	225034	.654363	.260874E 8
NOV360.DAT	.391617	204134	.595751	.270673E 8
NOV361.DAT	.209045	274485	.483530	.272596E 8
NOV362.DAT	.200207	332739	.532947	.264237E 8
NOV363.DAT	.198320	303911	.502232	.243745E 8
NOV364.DAT	.328554	338704	.567258	.253217E 8
NOV365.DAT	.236622	314112	.550734	.253803E 8
NOV1.DAT	.215374	248743	.464117	.253733E 8
NOV2.DAT	.220657	247152	.467809	.253633E 8
NOV3.DAT	.187730	183962	.371742	.236707E 8
NOV4.DAT	.189356	161191	.350547	.186246E 8
NOV5.DAT	.176660	139474	.316134	.187302E 8
NOV6.DAT	.253678	152898	.406567	.18598E 8
NOV7.DAT	.270523	110405	.380928	.185608E 8
NOV8.DAT	.241494	119283	.360777	.18308E 8
NOV9.DAT	.295126	128469	.423596	.1842E 8
NOV10.DAT	.534763	152925	.687688	.235653E 8
NOV11.DAT	.902301	210885	.111319E 7	.266199E 8
NOV12.DAT	.923486	247980	.117147E 7	.257464E 8
NOV13.DAT	.927140	257932	.118497E 7	.250564E 8
NOV14.DAT	.914354	324096	.113345E 7	.244186E 8
NOV15.DAT	.933041	327578	.116062E 7	.250783E 8
NOV16.DAT	.931249	185564	.1106881E 7	.263665E 8
NOV17.DAT	.462213	227034	.689246	.297963E 8
NOV18.DAT	.423367	218426	.641794	.376213E 8
NOV19.DAT	.475432	177681	.653113	.394781E 8
NOV20.DAT	.527275	193514	.720789	.386767E 8
NOV21.DAT	.634729	430712	.106544E 7	.367029E 8
NOV22.DAT	.303668	191296	.494965	.149128E 8
NOV23.DAT	0	0	0	0
NOV24.DAT	0	0	0	0
START BLEEDBACK				
NOV25.DAT	.112063E 7	298796	.141943E 7	-.141943E 7
NOV26.DAT	.15865E 7	.260693E 7	.419344E 7	-.419344E 7
NOV27.DAT	.912614	.258937E 7	.350199E 7	-.350199E 7
NOV28.DAT	.807037	.275552E 7	.356256E 7	-.356256E 7
NOV29.DAT	.855314	.235044E 7	.320576E 7	-.320576E 7
NOV30.DAT	.767881	.216763E 7	.293551E 7	-.293551E 7
NOV31.DAT	.600931	.202512E 7	.26261E 7	-.26261E 7
NOV32.DAT	.575510	.179571E 7	.237122E 7	-.237122E 7
NOV33.DAT	.545303	.171819E 7	.226349E 7	-.226349E 7
NOV34.DAT	.489088	.164353E 7	.213262E 7	-.213262E 7
NOV35.DAT	.449921	.150501E 7	.195493E 7	-.195493E 7
NOV36.DAT	.420921	.147171E 7	.189263E 7	-.189263E 7
NOV37.DAT	.363978	.139115E 7	.175513E 7	-.175513E 7
NOV38.DAT	.333492	.132637E 7	.165986E 7	-.165986E 7
NOV39.DAT	.311466	.124172E 7	.155318E 7	-.155318E 7
NOV40.DAT	.263877	.10588E 7	.132268E 7	-.132268E 7
NOV41.DAT	.188643	.694537	.863131	-.863131
NOV42.DAT	.187740	.792649	.980389	-.980389
NOV43.DAT	.341111E 7	.163607E 8	.197718E 8	-.197718E 8
STOP BLEEDBACK				
TOTAL	.770052E 8	.627086E 8	.139714E 9	.15562E 10
AVERAGE	.974750	.793779	.176853E 7	.196987E 8
TOTAL EQUIV				
GAL #2 DF	555.518	452.391	1007.9	11226.4

AVG ENERGY RECOVERY: 8.23928 %
 TOTAL RECOVERED GAS: .352515E 7 SCF
 ACTUAL AVG GHV: 17.7889 BTU/SCF
 BREAK-EVEN GHV: 459.244 BTU/SCF

ACTUAL FIELD DATA INCLUDING BLEEDBACK

FILE NAME	EQUIVALENT FUEL BTU'S TO DRIVE COMPRESSOR ENGINES		BTU'S CHEMICAL ENERGY	TOTAL INPUT ENERGY
	AIP + H2	METHANE		
NOV330.DAT	.241523E 8	134682	.231413E 7	.266011E 8
NOV331.DAT	.230568E 8	121212	.20837E 7	.252624E 8
NOV332.DAT	.242929E 8	357421	.612762E 7	.307779E 8
NOV333.DAT	.264532E 8	401980	.643994E 7	.333541E 8
NOV334.DAT	.260899E 8	492030	.761883E 7	.342008E 8
NOV335.DAT	.266053E 8	505726	.765961E 7	.347707E 8
NOV336.DAT	.270359E 8	569241	.856149E 7	.361667E 8
NOV337.DAT	.246357E 8	137160	.207396E 7	.268469E 8
NOV338.DAT	.268892E 8	309534	.462467E 7	.318334E 8
NOV339.DAT	.270608E 8	627495	.925913E 7	.369475E 8
NOV340.DAT	.270397E 8	635349	.935304E 7	.370331E 8
NOV341.DAT	.271067E 8	243913	.365979E 7	.310154E 8
NOV342.DAT	.259249E 8	348463	.514222E 7	.314156E 8
NOV343.DAT	.225092E 8	156368	.232906E 7	.249946E 8
NOV344.DAT	.25356E 8	375823	.557043E 7	.313023E 8
NOV345.DAT	.25472E 8	764481	.111365E 8	.37373E 8
NOV346.DAT	.261377E 8	773760	.111615E 8	.380729E 8
NOV347.DAT	.261891E 8	790352	.112971E 8	.382766E 8
NOV348.DAT	.261279E 8	781527	.111653E 8	.380747E 8
NOV349.DAT	.255392E 8	782950	.111607E 8	.375329E 8
NOV350.DAT	.249727E 8	763843	.109941E 8	.366306E 8
NOV351.DAT	.245207E 8	748305	.106026E 8	.358316E 8
NOV352.DAT	.235684E 8	530062	.749013E 7	.315896E 8
NOV353.DAT	.216771E 8	727912	.103978E 8	.328029E 8
NOV354.DAT	.190444E 8	568041	.843874E 7	.280512E 8
NOV355.DAT	.189292E 8	557781	.828459E 7	.277716E 8
NOV356.DAT	.189694E 8	492683	.729056E 7	.267526E 8
NOV357.DAT	.18999E 8	481728	.709282E 7	.264736E 8
NOV358.DAT	.188843E 8	504975	.734453E 7	.267333E 8
NOV359.DAT	.18882E 8	506144	.735367E 7	.267418E 8
NOV360.DAT	.189113E 8	565485	.818685E 7	.276636E 8
NOV361.DAT	.190141E 8	563579	.816549E 7	.277432E 8
NOV362.DAT	.189013E 8	521377	.753394E 7	.270067E 8
NOV363.DAT	.189132E 8	414749	.60488E 7	.253767E 8
NOV364.DAT	.192391E 8	426346	.622296E 7	.25839E 8
NOV365.DAT	.191432E 8	432452	.635541E 7	.25931E 8
NOV1.DAT	.191773E 8	429726	.62314E 7	.258374E 8
NOV2.DAT	.189679E 8	443464	.641974E 7	.258311E 8
NOV3.DAT	.189212E 8	333321	.478795E 7	.240424E 8
NOV4.DAT	.189751E 8	0	0	.189751E 8
NOV5.DAT	.190463E 8	0	0	.190463E 8
NOV6.DAT	.190045E 8	0	0	.190045E 8
NOV7.DAT	.189418E 8	0	0	.189418E 8
NOV8.DAT	.186688E 8	0	0	.186688E 8
NOV9.DAT	.188436E 8	0	0	.188436E 8
NOV10.DAT	.191378E 8	339366	.477531E 7	.24253E 8
NOV11.DAT	.192478E 8	563293	.7922E 7	.277331E 8
NOV12.DAT	.189475E 8	528108	.744213E 7	.269179E 8
NOV13.DAT	.178584E 8	551963	.783104E 7	.262414E 8
NOV14.DAT	.177116E 8	516760	.732875E 7	.255571E 8
NOV15.DAT	.176395E 8	567742	.803171E 7	.262339E 8
NOV16.DAT	.175748E 8	644200	.921436E 7	.274333E 8
NOV17.DAT	.195082E 8	669603	.103071E 8	.304955E 8
NOV18.DAT	.23332E 8	927462	.140036E 8	.382631E 8
NOV19.DAT	.239274E 8	.102573E 7	.151778E 8	.401312E 8
NOV20.DAT	.2391E 8	989573	.144979E 8	.393975E 8
NOV21.DAT	.234741E 8	923031	.133712E 8	.377694E 8
NOV22.DAT	.100883E 8	340096	.497892E 7	.154073E 8
NOV23.DAT	0	0	0	0
NOV24.DAT	0	0	0	0
START BLEEDBACK				
NOV25.DAT	0	0	0	0
NOV26.DAT	0	0	0	0
NOV27.DAT	0	0	0	0
NOV28.DAT	0	0	0	0
NOV29.DAT	0	0	0	0
NOV30.DAT	0	0	0	0
NOV31.DAT	0	0	0	0
NOV32.DAT	0	0	0	0
NOV33.DAT	0	0	0	0
NOV34.DAT	0	0	0	0
NOV35.DAT	0	0	0	0
NOV36.DAT	0	0	0	0
NOV37.DAT	0	0	0	0
NOV38.DAT	0	0	0	0
NOV39.DAT	0	0	0	0
NOV40.DAT	0	0	0	0
NOV41.DAT	0	0	0	0
NOV42.DAT	0	0	0	0
NOV43.DAT	0	0	0	0
STOP BLEEDBACK				
TOTAL	.125911E 10	.279136E 9	.408889E 9	.163591E 10
AVERAGE	.159321E 8	353337	.51759E 7	.214672E 8
TOTAL EQUIV				
GAL #2 DF	9033.24	201.37	2949.73	12234.3

APPENDIX B

Carbon balance - source of extracted carbon

Appendix B

Figure 31 shows the in situ process as visualized in the CH_x model. Methane and air, at an (air/fuel) ratio of R_1 , are fed to a downhole burner and totally combusted:

Basis: 1 mole methane to burner $R_1 \geq 10$

The burner exhaust consists of unburned O_2 , CO_2 , H_2O vapor, and N_2 . The system is not totally sealed and so some gas at the burner exhaust composition may escape. Now, an unknown hydrocarbon gas with an empirical formula CH_x is mixed with the fraction of burner exhaust which does not escape. This mixture passes through a combustion zone and is totally oxidized.

$$\text{let } C_1 = \frac{\text{Moles } \text{CH}_x \text{ burned underground}}{\text{Mole Methane fed to burner}}$$

$$\text{let } R_2 = \frac{\text{Moles burner exhaust not lost}}{\text{Total Moles burner exhaust}}$$

$$\text{let } R_3 = \frac{\text{Moles product gas recovered}}{\text{Total Moles product produced}}$$

The CH_x gas may have come from any or all of the following sources:

1. Pyrolysis products from shale retorting
2. Naturally occurring shale gas
3. Actual combustion of In Situ shale kerogen and/or char

C_1 can be determined from a carbon balance:

$$\left[\begin{array}{c} \text{Moles C into shale} \\ \text{formation} \end{array} \right] = R_2$$

$$\left[\begin{array}{c} \text{Moles C from } \text{CH}_x \\ \text{gas} \end{array} \right] = C_1$$

$$\left[\begin{array}{c} \text{Moles C} \\ \text{recovered} \end{array} \right] = R_3 (R_2 + C_1)$$

FIGURE 31

Solving for C_1 :

$$C_1 = \frac{\left[\begin{array}{c} \text{Moles C} \\ \text{Recovered} \end{array} \right]}{R_3} - R_2$$

The combusted gas flows to a production well where a fraction of it may be lost. The R_3 fraction is recovered and analyzed.

The product gas composition (dry basis) may be determined from the stoichiometric coefficients:

$$\text{let } [\text{Denominator}] = \underbrace{(R_2 + C_1)}_{\text{CO}_2} + \underbrace{(0.2 R_1 R_2 - 2R_2 - C_1 - \frac{C_1 X}{4})}_{\text{O}_2} + \underbrace{0.8 R_1 R_2}_{\text{N}_2}$$

$$X_{\text{CO}_2} = \frac{(R_2 + C_1) R_3}{[\text{Denominator}] R_3}$$

$$X_{\text{O}_2} = \frac{(0.2 R_1 R_2 - 2R_2 - C_1 - \frac{C_1 X}{4}) R_3}{[\text{Denominator}] R_3}$$

$$X_{\text{N}_2} = \frac{(0.8 R_1 R_2) R_3}{[\text{Denominator}] R_3}$$

On March 16, 1980 during the FY-80-3 extraction trial, conditions were nearly ideal for application of the CH_x model:

$$\text{Avg (Air/Fuel)} = 37.32$$

$$\left[\begin{array}{c} \text{Moles C injected} \\ \text{into burner} \end{array} \right] = 15.8 \text{ lb-mole}$$

$$\left[\begin{array}{c} \text{Moles C} \\ \text{recovered} \end{array} \right] = 31.6 \text{ lb-mole}$$

Fairly steady injection and production flow rates

$$\text{Avg } [\text{Recovery}] = 66.6\%$$

Avg Production Composition

CO : 0.16%_{vol}
 CO₂: 7.42%_{vol}
 CH₄: 0.26%_{vol}
 O₂ : 9.35%_{vol}

The %_{vol} CO₂ and %_{vol} O₂ curves crossed over twice that day at 8.1 %_{vol} and 8.2 %_{vol}.

The CH_x model can be used to determine a theoretical CO₂ - O₂ crossover under two limiting cases:

Case 1: Assume all recovery is lost at the production well
 R₂ = 1 and R₃ = 0.666

Case 2: Assume all recovery is lost at the injection well
 R₂ = 0.666 and R₃ = 1

C ₁	Moles CH _x Mole methane fed to burner	Case 1	Case 2
		2.00	1.33
% _{vol} CO ₂ - O ₂ crossover		8.4	8.4
(H/C) ratio in CH _x		0.93	0.94

For such a crude model, the predicted CO₂- O₂ crossover of 8.4 %_{vol} compares very well to the observed crossovers of 8.1 %_{vol} and 8.2 %_{vol}.

The (H/C) ratio of the CH_x gas most closely matches the (H/C) ratio of shale kerogen:

	(H/C)
CH _x	0.935
Shale kerogen	1.1
Natural Shale Gas	3.73
Methane	4.0

This leads to the conclusion that essentially all the excess carbon in the carbon balance must have come from combustion of shale retort products and/or in situ shale kerogen/char combustion. Very little if any natural shale gas or methane was involved.

APPENDIX C

Data Plots F80-3

<u>Data</u>	<u>Number of Plots</u>
Injection Well 305	3
Production Well 306 (flow & pressure)	3
Production Well 306 (gas analysis)	3
Production Well 301 (flow & pressure)	3
Production Well 301 (gas analysis)	3
Well 305 & 306 (bleeddown)	1

INJECTION WELL WELL 305

WELL 306 PRODUCTION GASES

WELL 306 PRODUCTION GASES

WELL 301 PRODUCTION GASES

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APPENDIX D

Data Plots F80-2

<u>Data (vs time)</u>	<u>Number of Plots</u>
-----------------------	------------------------

Injection Well

1. Injection Air Pressure	
2. Injection Air Flow	7
3. Theoretical Temperature °F/2	
4. Total Air/Methane Ratio x10	

305, 306

1. % vol. CO ₂	
2. % vol. O ₂	14
3. % vol. THC	

305, 306

1. Back Pressure	
2. Production Flow	14

Total

1. Apparent Recovery	
2. Total Flow	
3. % vol. CO ₂	7
4. % vol. O ₂	
5. % vol. THC

100

APPENDIX E

Data Plots F80-1