EASTERN GAS SHALES PROGRAM

RESERVOIR VERIFICATION TESTING

OF

SAPPINGTON CRUDE OIL, INC.

RONALD J. BISCHOFF WELL NO. 1-15

OGEMAW COUNTY, WEST BRANCH, MICHIGAN

Final Report

by

Donald W. Butler

Work Performed for the Department of Energy
Under Contract DE-AC21-81MC16436

GRUY FEDERAL, INC.
2500 Tanglewilde, Suite 150
Houston, Texas 77063
713/785-9200

March 1982

EASTERN GAS SHALES PROGRAM

RESERVOIR VERIFICATION TESTING

OF

SAPPINGTON CRUDE OIL, INC.

RONALD J. BISCHOFF WELL NO. 1-15

OGEMAW COUNTY, WEST BRANCH, MICHIGAN

Final Report

by

Donald W. Butler

Work Performed for the Department of Energy
Under Contract DE-AC21-81MC16436

GRUY FEDERAL, INC.
2500 Tanglewilde, Suite 150
Houston, Texas 77063
713/785-9200

March 1982

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

This report contains a discussion of field activities and subsequent data generated from reservoir verification testing performed in Sappington Crude Oil, Inc. Ronald J. Bischoff Well No. 1-15, Ogemaw Township, Ogemaw County, Michigan. Figure 1 shows the location of the Bischoff Well No. 1-15 in Ogemaw County and the State of Michigan. Figure 2 shows the location of the well on a county map in relation to roads and other improvements and Figure 3 shows the well location on the Ogemaw Springs 7.5 minute topographic quadrangle. The well was selected as a candidate for participation in the Eastern Gas Shales Program as it met the requirements outlined by the U. S. Department of Energy/Morgantown Energy Technology Center (DOE/METC) contract No. DE-AC32-81MC16436 with Gruy Federal, Inc. More specifically, it is located in the Saginaw Bay region of the Michigan Basin and is completed through the Antrim Shale formation in the Chautauquan Series of the Upper Devonian period (Fig. 4).

The well was rotary drilled with fluid during the week of January 25, 1982 to a total depth of 4,465 ft (logger). Gas shows were reported in the Antrim formation. The casing program consisted of 8-5/8 inch surface casing set at 716 ft with 5-1/2 inch, 15.5 lb per ft production casing set at T.D. A bridge plug was set at 2,336 ft. Logging revealed an excellent cement bond with the top of cement at 1,690 ft.

The casing and formation were perforated with 17 shots through an interval of 128 ft, ranging from 2,000 ft to 2,128 ft. The interval was broken down with a foamed acid treatment consisting of 1,500 gal of regular HF acid (excludes a 300-gallon acid spot across perforations) with perforation ball sealers used as flow diverters. Upon flowback and cleanup to remove the acid, the well was treated with a 75 percent quality, 50,000-gallon foam fracturing treatment using 60,000 lb of sand proppant.

Upon completion of the testing program, the well exhibited an open flow of 2.6 Mcf/D. Analysis of the gas flowing from the wellbore after flowing open for one week revealed a nitrogen content of 52.6 percent and methane content of 36.20 percent.

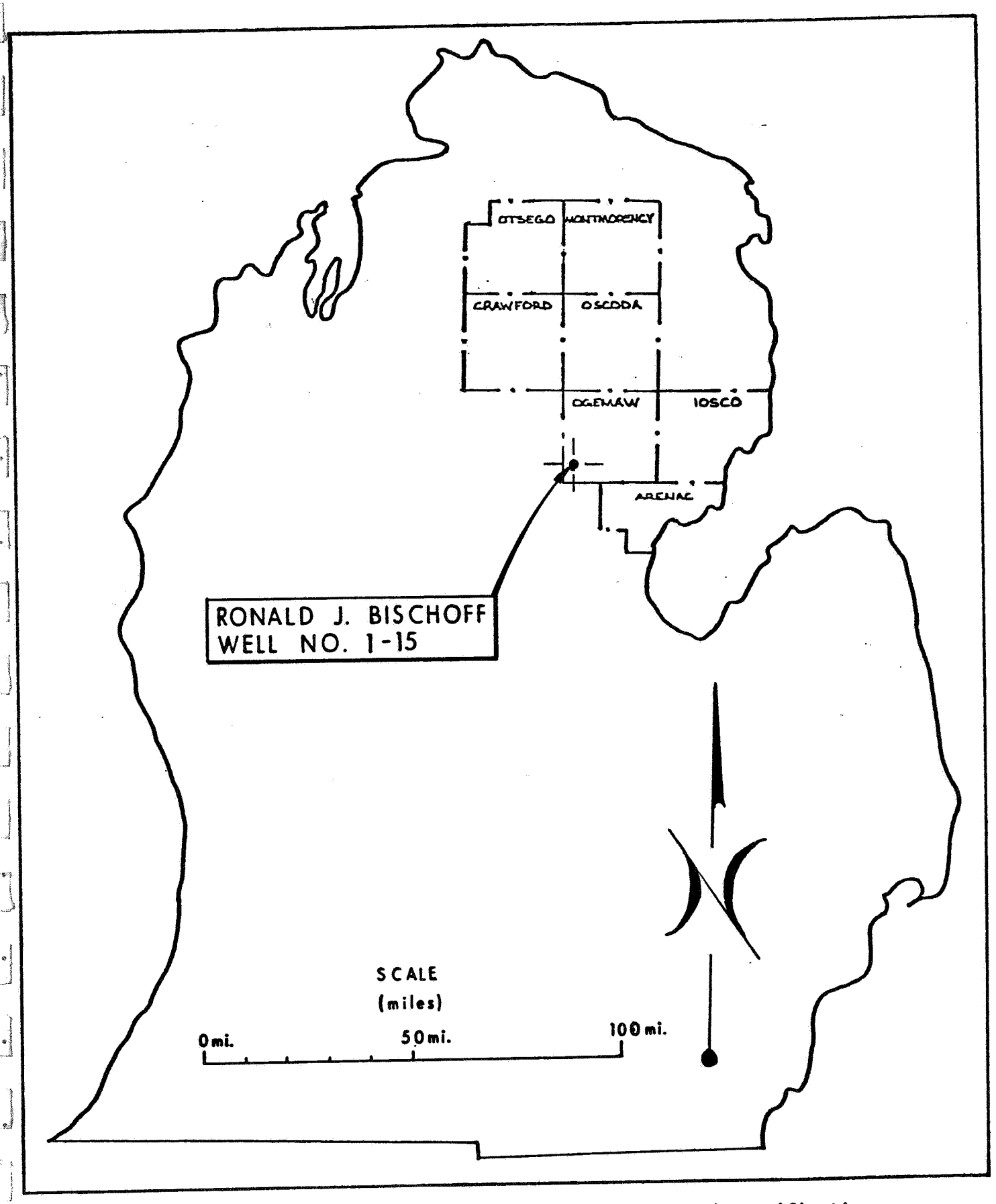

Figure 1.--Michigan target counties for reservoir verification testing in Eastern Gas Shales Program.

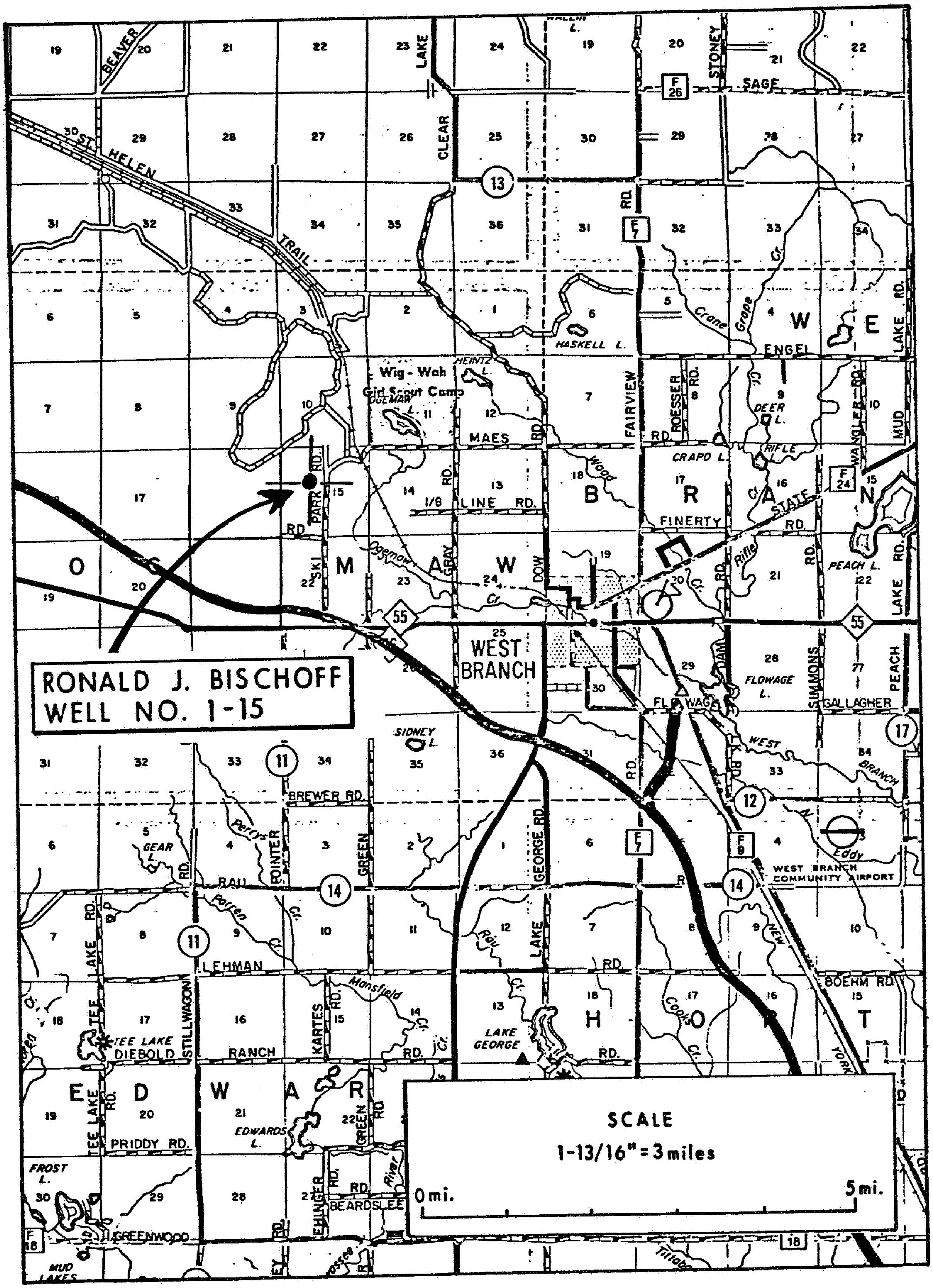

Figure 2.--County map Ronald J. Bischoff No. 1-15.

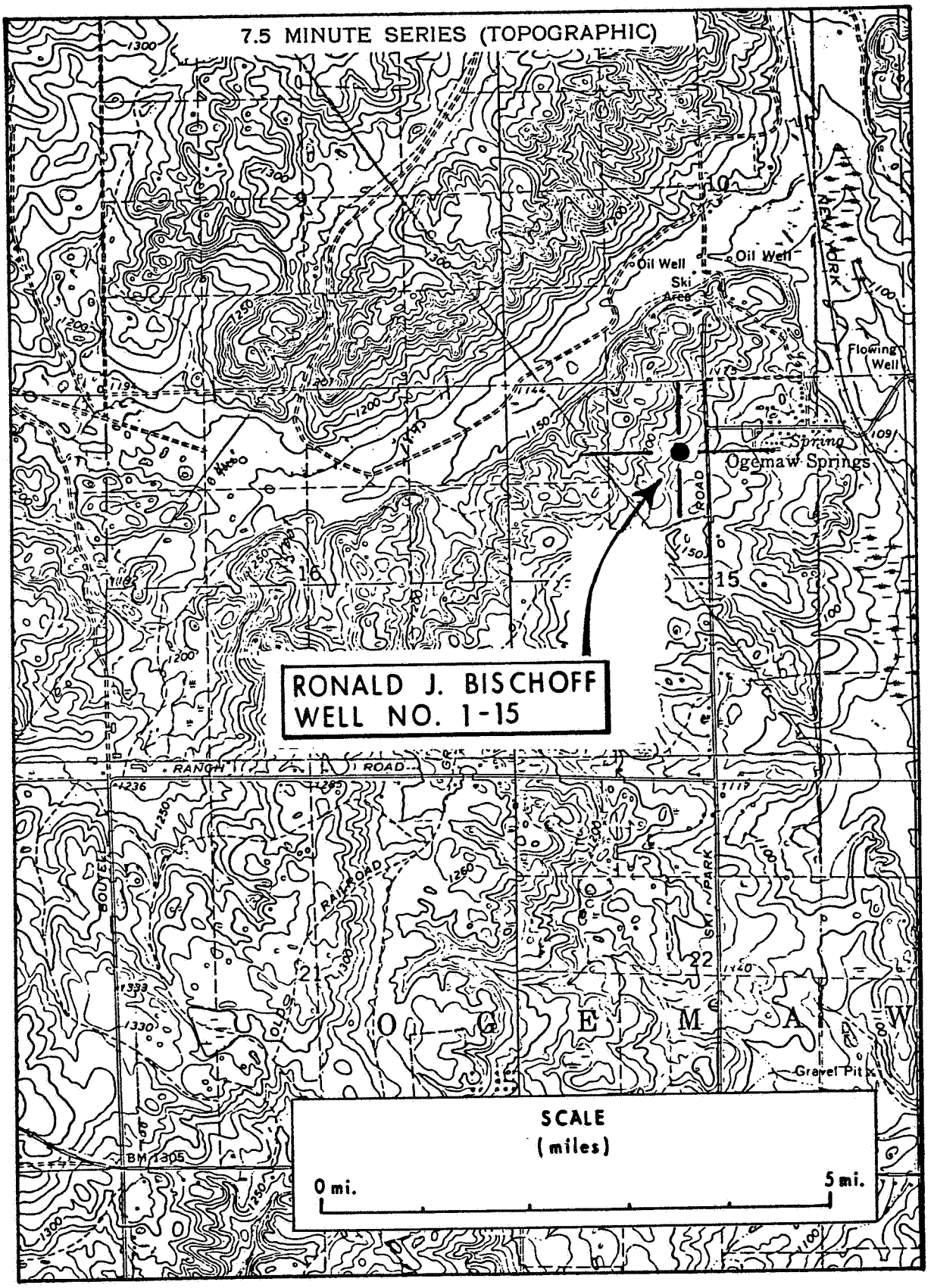

Figure 3.--Location map of Ogemaw Springs quadrangle Michigan.

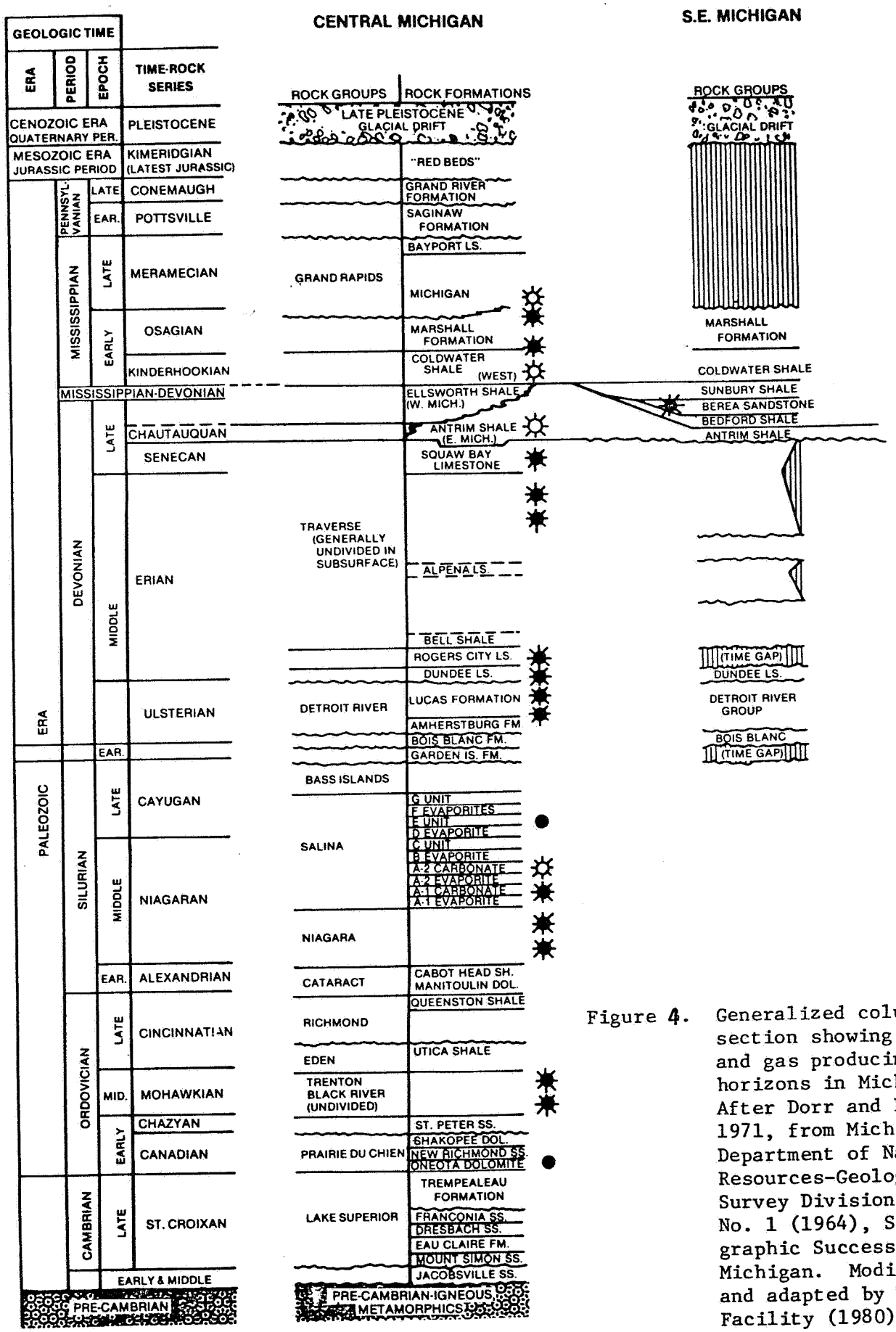

Figure 4. Generalized columnar section showing oil and gas producing horizons in Michigan. After Dorr and Eschman, 1971, from Michigan Department of Natural Resources-Geological Survey Division Chart No. 1 (1964), Stratigraphic Succession in Michigan. Modified and adapted by Mound Facility (1980).

DESCRIPTION OF FIELD ACTIVITIES

Field activities began on March 9, 1982 by running a Schlumberger perforating depth control (PDC) log. This was followed by a cement bond log-variable density log (CBL-VDL) which revealed an excellent cement bond with the top of the cement located at 1,690 ft. Bailing operations were initiated and continued throughout remainder of the day.

On March 10, 1982, bailing was completed to a depth of 2,135 ft. Perforating was conducted in the Antrim Shale with 3-3/8 inch Hyperjet II hollow carrier guns from 2,128 ft to 2,000 ft. Perforation diameter was 0.375 in. Halliburton performed the foamed acid treatment immediately after perforating by breaking down the formation with 1,500 gal of regular HF acid. A 300-gallon spot of HF acid preceded the treatment. Halfway through the treatment, the pumps were shut down and an instantaneous shut-in pressure of 2,050 psi was recorded. Pumping was then resumed with a total of 26 perforation ball sealers being dropped at a rate of one per every 29 gal of acid. Upon completion, the well was unloaded and swabbed and bailed in preparation for the foam fracturing. The bottomhole treating pressure was calculated at 2,419 psi, the frac gradient at 1.14 and the stress ratio factor at 0.99.

On March 11, 1982, a fracture treatment consisting of a 75 percent, 50,000-gallon foam frac was performed. The process used a total of 10,000 lb of 80/100 mesh sand, 50,000 lb of 20/40 mesh sand and 4 cans of R-192 radioactive tracer beads. An instantaneous shut-in pressure of 1,810 psi was recorded upon completion of the job which decreased to 1,780 psi after 15 minutes. The well was opened on an adjustable choke set at 8/64 in. Shut-in pressure prior to opening well was 1,580 psi. After thirty-seven minutes (flowing pressure of 1,480 psi), the choke cut out due to sand erosion and the well was immediately shut in. The choke was changed to another adjustable type of sturdier design. After being shut in for twenty-three minutes, the well was opened up on 8/64-in. The well flowed N_2 water and some sand. Ninety minutes later, with a flowing pressure of 1,300 psi, the second choke was sand cut and the well was again shut in. A positive 1/8-inch choke was then placed on the wellhead and, with a shut-in pressure of 1,690 psi, the well was opened after three hours.

By the morning of March 12, the pressure had declined to 210 psi. The choke size was changed to 1-in. and the remaining pressure bled off in minutes. A wireline was run which located a fluid level at 150 ft and bottom at 2,236 ft. This corresponded to 100 ft of sand above the bridge plug with the perforations clear by 108 ft. Total fluid recovery was approximately 160 bbl or 51 percent of total liquid injected. The actual treatment requirements and fracture schedule are listed on Tables 1 and 2, with the results found on Table 3.

Swabbing and bailing operations were initiated to remove fluids from the wellbore and continued until it was fluid free. The well flowed open for five days before it was shut in to record a pressure buildup for three days. The well was then opened to the atmosphere to permit the continued flow of nitrogen from the formation. This was carried out for three days.

TABLE 1

RONALD J. BISCHOFF WELL NO. 1-15

OGEMAW COUNTY, MICHIGAN

INDIVIDUAL TREATMENT PROFILE FOR WELL

Treatment Requirements

	Acid Treatment	Frac Treatment
Regular HF Acid, Gal	1,800	
Foam Rate, Bbl/Min	6	23.5
Foam Quality, %	72.5	75
Foam Volume, Gal	6,000	50,000
Nitrogen Used, Scf	167,000	836,000
Nitrogen Rate, Scf/Min	3,450	15,200
N_2 to Liquid Ratio, Scf/Bbl	2,300	2,576
HAI-50 Inhibitor, Gal	4	
CLA-STA II, Gal		13
Hy-Clear 2 Foamer, Gal		65
Perf Balls (S.G. = 1.3)	26	
Sand 80/100 Mesh, Lb		10,000
Sand 20/40 Mesh, Lb		50,000
R-192 Tracer Beads, Cans		4

TABLE 2

RONALD J. BISCHOFF WELL NO. 1-15

OGEMAW COUNTY, MICHIGAN

FOAM FRAC TREATMENT SCHEDULE

STAGE	BBL OF FOAM	SAND LB	SIZE	BBL OF LIQUID	CUM BBL LIQ + SAND	SAND LB/GAL LIQUID	LIQ + SAND RATE, BPM
1	238	0		59.5	59.5	0	5.9
2	238	10000	80/100	59.5	129.8	4	7.0
3	476	30000	20/40	119.0	281.2	6	7.5
4	238	20000	20/40	59.5	362.3	8	8.0
5	58.7	0		14.6	375	0	5.9

TABLE 3

INDIVIDUAL TREATMENT

RESULTS OF RONALD J. BISCHOFF WELL NO. 1-15

ACID TREATMENT	
Average Treatment Pressure	
I.S.I.P.	2050 PSI
B.H.T.P.	2419 PSI
Frac Gradient	1.14
Stress Ratio	0.99

FOAM FRACTURING	
Average Treatment Pressure	2330 PSI
I.S.I.P.	1810 PSI
Shut-in Pressure, 5 Min	1800 PSI
10 Min	1790 PSI
15 Min	1780 PSI
Fracture Extension, Vertical	0 FT
Open Flow Before	0 MCFD
Open Flow After	2.6 MCFD

It must be noted, however, that liquids entering the wellbore would kill the flow due to extremely low flow potential. Bailing operations were conducted once daily to remove these liquids. On March 22, 1982, Schlumberger arrived on location to perform production logging. Prior to their arrival, the well had been bailed out to permit gas flow. After flowing four hours, a gas sample was taken to determine the chemical composition of the gas escaping from the wellbore.

Production logging was initiated after taking three hours to rig up. By this time, enough fluid had entered the casing to halt the flow of gas into the wellhore. The production tool was run into the hole with the fullbore spinner attached.

A composite photograph of the pre-stimulation and post-stimulation logs appear in Fig. 5 with the results on the gas analysis found on Table 4.

Analyses of these logs has revealed the following:

- The fluid level in the casing was increasing with time. During the last pass, it was found at 1,782 ft.

- Gamma-ray tracer survey does not indicate a vertical fracture extension above the top perforation (2,000 ft). This is revealed by the lack of a radically heightened response of the tool to the presence of radioactive tracer beads which were carried into the formation during the fracture treatment. Rather than having extended vertically, the fractures may have traveled horizontally. The survey shows that the formation at an interval of 2,096 ft and 2,104 ft may not have treated as well as the other intervals. This may possibly be accounted for by a compositional variation in the formation as shown by the compensated neutron-density log.

- The temperature log indicates gas movement behind the casing in an interval between 2,030 ft and 2,038 ft. Previous passes with the instrument showed this anomoly to be deeper down the wellbore.

- The main gas entry into the wellbore is from the top perforation at 2,000 ft. This is indicated by the temperature, gradiomanometer and flowmeter responses.

The following day, March 23, the well was cleared of all fluids and an open flow test was performed using an orifice tester in conjunction with a 1/4-inch orifice. The open flow potential of Ronald J. Bischoff No. 1-15 was measured to be 2.6 Mcf/D.

RONALD J. BISCHOFF 1-15

Figure 5

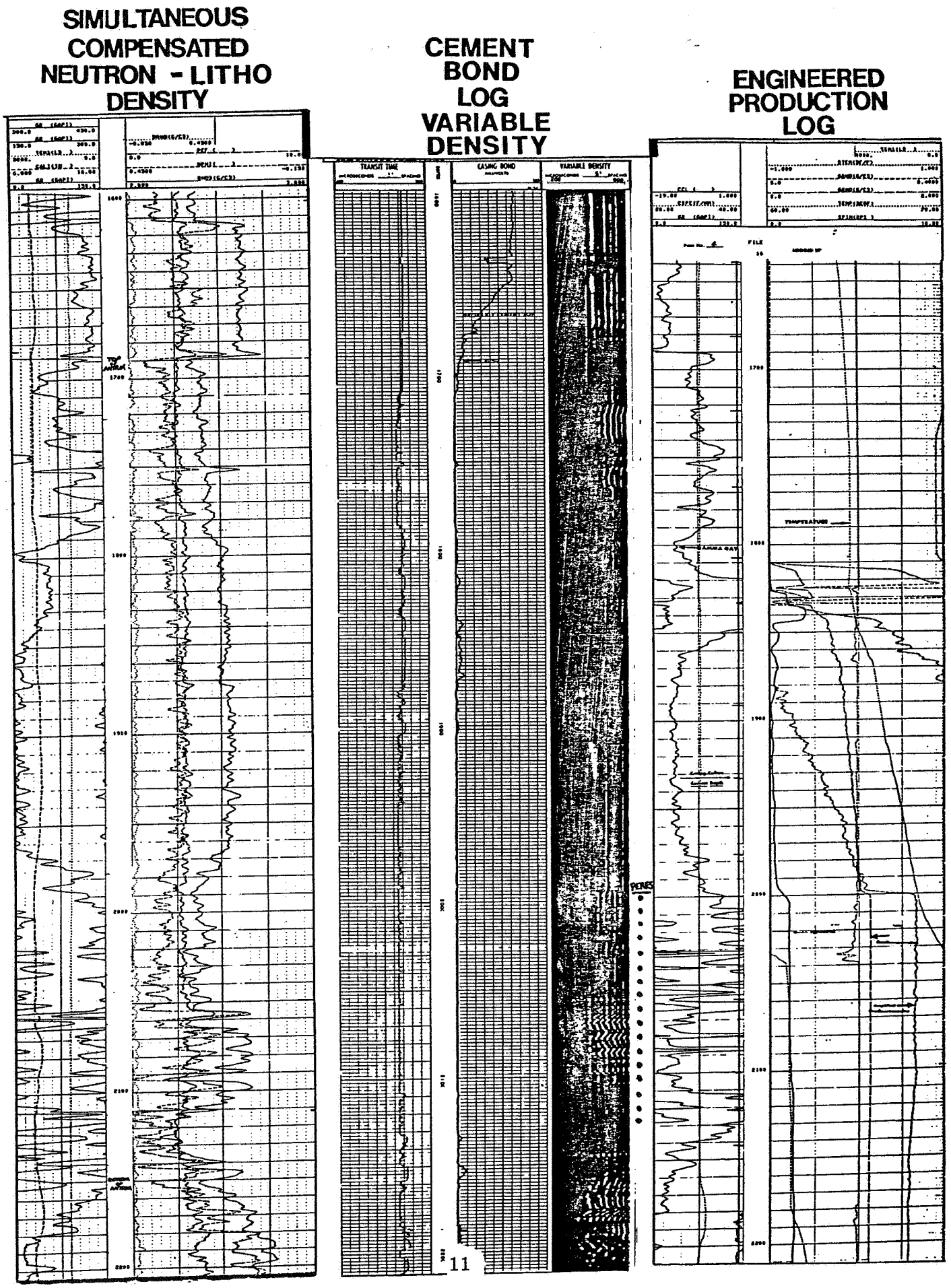

TABLE 4

ANALYSIS OF GAS SAMPLE

FROM

RONALD J. BISCHOFF WELL NO. 1-15

COMPONENT	MOL %	GPM @ 14.696 PSIA
Nitrogen	52.55	
Carbon Dioxide	2.67	
Methane	36.20	
Ethane	2.67	
Propane	3.73	1.024
Iso-Butane	1.69	0.551
N-Butane	0.33	0.104
Iso-Pentane	0.04	0.015
N-Pentane	0.04	0.014
Hexanes	0.01	0.004
Heptanes Plus	0.07	0.032
	100.00	1.744

Specific Gravity @ 60°F. 0.8802

Calculated Btu/cu ft @ 14.696 Psia and 60°F

Dry Basis 580

Wet Basis 570

CONCLUSIONS

1. The quality of the cement bond log was excellent, which precluded any communication or migration of treating fluids or hydrocarbons behind the casing.

2. The casing was perforated with a hollow carrier which insures that the impact of the firing was absorbed by the gun rather than the casing.

3. The casing was empty when perforated, which resulted in a pressure differential into the wellbore rather than into the formation.

4. Perforation ball sealers were successful in assuring acid treatment of the formation. This was revealed in pressure increases during the treatment as the balls progressively sealed the perforations.

5. The Antrim formation in the Ronald J. Bischoff Well No. 1-15 exhibited a stress ratio of 0.99. Defined as the ratio of minimum horizontal pressure caused by tectonic tension or compression to vertical pressure caused by overburden, it is regarded that favorable productive trends may exist in areas where the stress ratio factor is less than 0.50. The implication being that the lower the stress ratio an area exhibits, the higher the fracture density and, consequently, the larger the reservoir capacity of the formations. The Bischoff 1-15 apparently has a very low reservoir capacity due to the absence of a good natural fracture system.

6. The fractures may have extended horizontally in the formation. The lack of high gamma-ray responses above 2,000 ft tends to indicate this. Consequently, the response above 2,000 ft on the neutron-density log appears to match the response acquired during post-stimulation production logging.

7. The entire section of perforated formation was fractured as revealed by the presence of radioactive tracer beads in each of the perforated intervals. A question arises as to the degree of fracturing in the interval between 2,096 ft and 2,104 ft. The lower response of the tool to the tracer beads in this section indicates that this section did not treat as well as the adjoining areas. The compositional variation in the formation in this section may be accountable for this phenomenon.

8. The small amount of fluid found entering the wellbore was sufficient to kill the flow of gas from the formation. This is attributed to the extremely low productivity of the well.

ACKNOWLEDGMENTS

The author wishes to thank Sappington Crude Oil, Inc. of West Branch, Michigan for their cooperation and assistance in making their well available for testing in the Eastern Gas Shales Program.

REFERENCES

Curtis, M. R., "Flow Analysis in Producing Wells", 1967, SPE Paper 1908, 42nd Annual Fall Meeting of the Society of Petroleum Engineers of AIME, October 1967.

Daneshy, Abbas Ali, 1973, "Experimental Investigation of Hydraulic Fracturing through Perforations", Journal of Petroleum Technology, October, 1973.

Gruy Federal, Inc., 1982, under contract No. DE-AC21-81MC16436 by DOE, "Reservoir Verification Testing of Caltek Minerals, Inc. Forrest Taylor No. 1, Independence Township, Washington County, Ohio - Final Report", Donald W. Butler, January 1982.

Komar, C. A., Yost, A. B. and Sinclair, A. Richard, 1980, "Foam Fracturing the Devonian Shale", World Oil, July 1980.

Kung, K. S. and Tixier, M. P., 1955, "Temperature Surveys in Gas Producing Wells", Journal of Petroleum Technology, July 1955.

Schlumberger Document, 1970, Production Log Interpretation.

Tetra Tech, Inc., under contract No. DE-AC21-79MC10389 by DOE, "Evaluation of Devonian Shale Potential in the Michigan Basin", DOE/METC-123.

Warpinski, N. R., Schmidt, R. A. and Northrup, D. A., 1982, "In-Situ Stresses: The Predominant Influence on Hydraulic Fracture Containment", Journal of Petroleum Technology, March 1982.

APPENDIX A

Sappington Crude Oil, Inc.
Ronald J. Bischoff Well No. 1-15
Ogemaw County, West Branch, Michigan

Field Report

RONALD J. BISCHOFF WELL NO. 1-15
OGEMAW COUNTY, MICHIGAN

FIELD REPORT

March 9, 1982 — Pre-Perforating Logging

8:00 Gruy Federal arrived on location. Schlumberger arrived on location and began rigging up.

9:05 Schlumberger began perforating depth contol (PDC) logging.

10:30 Schlumberger began running CBL-VDL, CCL logging.

12:30 Logging complete to top of bridge plug at 2,336 ft. Cement top = 1,676 ft. The bond was excellent from 1,700 ft to plug. Schlumberger rigged down.

13:00 Lease Management Services assembled bailer onto wireline and prepared to remove fluid from wellbore.

13:45 Bailing operations initiated.

18:45 Bailing operations halted for day with fluid level down to 1,700 ft.

March 10, 1982 — Perforating and Acid Treatment

7:00 Gruy Federal and Lease Management arrived on location. Fluid level checked and found at 1,720 ft.

7:40 Resumed bailing operations.

9:32 Bailing completed to 2,135 ft. Riggd up Schlumberger for perforating.

10:02 Began perforating 5-1/2- inch, 15.5 lb casing at 2,128 ft after depth correlation. Using 3-3/8- inch hollow carrier Hyperjet II gun, the following interval was perforated:

2,000 ft - 2,128 ft (17 shots, one every 8 ft)
Diameter of hole = 0.375 in.

13:45 Rigged down Schlumberger.

14:01 Rigged up Halliburton for acid treatment.

15:25 Tested lines at 5,000 psi. Encountered leak in ball injector and malfunction in flow analyzer; corrected.

15:40 Spotted 300 gal of regular HF acid across perforations (12 percent HCl-3 percent HF).

15:53 Began loading hole with foamed acid:

Q Acid = 1.5 Bbl/min
QN2 = 3450 Scf/min

16:02 Shut pumps down after pumping 3,000 gal of foamed acid. Recorded instantaneous shut-in pressure (I.S.I.P.) of 2,050 psi (gauge). Calculated foam quality, X = 0.725 and bottomhole treating pressure, BHTP = 2,439 psi.

16:17 After 15 minute delay to fill flush tanks, began pumping remaining 3,000 gal of foamed acid while injecting a perf ball every 29 gal of acid pumped.

16:32 With all 26 balls away, flush was initiated.

16:56 Stopped pumps; job completed. Recorded I.S.I.P. of 2,000 psi.
5 minute shut-in = 1,800 psi.
10 minute shut-in = 1,800 psi.
15 minute shut-in = 1,800 psi.

Used 1,800 gal of acid (including spot) and 167,000 Scf N_2.

17:11 Rigged down Halliburton and assembled choke assembly onto wellhead.

18:00 Opened well up on 1-inch choke. Well bringing back N_2 and some fluid.

18:15 Well opened up to 2 in.

18:25 Well died. Shut in overnight.

March 11, 1982 Clean-Up and Foam Fracturing

7:00 Gruy arrived on location. Pressure shut-in = 340 psi.

7:28 Opened well up and blew it down.

7:30 Well died.

8:30 Lease Management arrived on location and checked fluid. Found a froth level at 500 ft. Began bailing below froth level.

9:50 Well clean-up continued.

11:15 Bailing halted.

11:30 Fluid level checked. Well made 30 gal of fluid.

12:00 Halliburton arrived on location.

12:20 Checked fluid level. Found 100 ft higher. Continued bailing.

13:20 Stopped bailing; fluid level at 1,100 ft (900 ft above top perf). Rigged up Halliburton.

14:54 Tested lines at 5,000 psi; lines O.K.

15:00 Solenoid on N_2 pumping starter broke. Initiated repair.

16:58 Begin to fill hole with pad. QN_2 = 15200 Scf/min, Q Fluid - 5.9 Bbl/min.

17:08 Started 80/100 sand with proppant concentration at 1 lb/gal foam. Pressure = 2,380 psi. Began dumping tracer beads at steady rate.

17:18 10,000 lb of 80/100 away. Started 20/40 sand at 1.5 lb/gal foam. Pressure = 2,410 psi.

17:38 30,000 lb of 20/40 away. Increased concentration to 2.0 lb/gal foam. Pressure = 2,330 psi.

17:49 50,000 lb of 20/40 away. Initiated foamed water flush.

17:51 Shut pumps down; job completed. I.S.I.P. recorded at 1,810 psi.
5 minute shut-in = 1,800 psi.
10 minute shut-in = 1,790 psi.
15 minute shut-in = 1,780 psi.

Used 312 bbl liquid and 836,000 Scf N_2.

18:06 Rigged down Halliburton and piped in an adjustable choke assembly onto wellhead.

19:00 Opened up Ronald J. Bischoff Well No. 1-15 on 8/64-inch choke. P shut-in = 1,580 psi. Well flowing N_2, H_2O and some sand.

19:37 P flowing = 1,480 psi. Choke body cut out; shut well in. Installed a new adjustable choke.

20:00 Opened well up on 8/64-in. Flowing N_2, H_2O and some sand.

21:30 Choke body cut out; P flowing = 1,300 psi. Shut well in and changed to a positive choke body.

March 12, 1982

1:00 New 8/64-inch choke placed on well. P shut in = 1,690 psi. Well opened up.

10:00 P flowing = 550 psi. Shut well in and changed choke size. P shut-in = 640 psi.

10:40 Opened well up on 32/64-inch choke; P flowing = 210 psi.

11:00 Opened well up on 1-inch choke; P flowing = 100 psi.

12:30 P flowing = 20 psi. Began swabbing operations. Fluid level found at 150 ft. TD = 2,236 (100 ft to plug). Perforations clear. Fluid recovery during flowback approximately 160 bbl.

17:00 Stopped swabbing at 1,700 ft. Shut well in overnight.

March 13, 1982

9:00 Gruy Federal arrived on location. Shut-in pressure = 1,100 psi. Placed a tee on wellhead to catch fluid sample.

9:42 Opened well up and blew it down. Well brought back N_2, H_2O and natural gas in form of an atomized mist. Black formation fines also brought up.

10:26 Dropped a line down to check fluid level. Found level at 2,118 ft.

10:50 Allowed well to flow open. Well emitting N_2 and natural gas.

11:12 Assembled flow line onto wellhead to pit area. Attempted to flare gas. Gas would not ignite.

11:30 Gruy Federal arrived at office of Sappington Crude Oil, Inc. Discussed possibility of allowing Ronald J. Bischoff 1-15 to flow open for a week to permit the escape of residual N_2 prior to post-stimulation testing. Request granted and testing scheduled for March 22.

March 22, 1982

13:00 Gruy Federal arrived on location. Well had been swabbed and bailed earlier in the day to remove fluid from across perforations which was killing gas flow. Obtained a flow which initially brought back some fluid, N_2 and natural gas. Well flowed for approximately 4 hours before shut-in to reduce 2-inch opening to 1/2-in. to permit the placing of gas sampling bottles on the wellhead.

13:10 Southern Petroleum Laboratories took three samples for analysis.

14:00 Schlumberger arrived on location. Began rigging up for production logging.

15:30 Schlumberger calibrated new tools to CSU unit. Experienced complications and forced to troubleshoot and debug equipment.

17:00 Schlumberger entered well with production profile tools. Flow from wellhead had died by this time due to migration of fluids into wellbore. Initiated logging operations.

20:42 Logging completed. Rigged down Schlumberger.

March 23, 1982

7:00 Gruy Federal and Lease Management Services arrived on location. Well open but not flowing.

7:13 Dropped bailer down and initiated cleanup operations.

8:35 Southern Petroleum arrived on location. Began rigging up for orifice testing of open flow. Well now flows N_2 and natural gas. Bailing operations continued. Well making some marginal fluid.

9:10 With perforations clear and well flowing, Southern Petroleum Laboratories initiated orifice testing Ronald J. Bischoff 1-15.

9:30 Testing completed. Open flow through 1/4-inch orifice on 20 minute cycle found steady at 2,610 Scf/D.

9:35 Rigged down Southern Petroleum. Job completed.