SWD 11/2/98

Texaco E & P

205 E. Bender Blvd.
Hobbs NM 88240
505 393 7191

RECEIVED
OCT 16 1998
OIL CONSERVATION DIVISION

October 15, 1998

NMOCD
2040 South Pacheco
Santa Fe, New Mexico 87505

Attn : Mr. David Catanach

RE : Application for Producing Oil Well / Saltwater Disposal Well
Bilbrey 30 Federal #5
Delaware Formation
1980' FSL & 1980' FEL, Section 30, T-21-S, R-32-E
Lea County, New Mexico

Dear Mr. Catanach,

Texaco Exploration & Production, Inc. respectfully requests administrative approval for the attached C-108 application on its Bilbrey 30 Federal #5 well for the purpose of disposing of produced fluids in a non-commercial Delaware interval below a productive Delaware interval. This work will allow Texaco to reduce current water disposal costs associated with the subject lease. Dually completing the subject well as a producing oil well and a SWD will lower the lease's economic limit and allow Texaco to recover additional oil and gas reserves that would otherwise be left in place.

This well is located at Unit Letter J : Section 30, T-21-S, R-32-E. Texaco respectfully requests that this application approved administratively at the earliest possible convenience so that operations can be advanced in a prudent manner. If you have any questions concerning the application, please contact me at (505) 397-0484.

Sincerely,

Jason Wacker
Production Engineer
Texaco Exploration & Production, Inc.

AOR
5 TOTAL
0 P&A
0 REPAIR

JHW/
Attachments
File

BS

ENERGY AND MINERALS DEPARTMENT

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501

Revised 7-1-81

APPLICATION FOR AUTHORIZATION TO INJECT

I. Purpose: [X] Secondary Recovery [ ] Pressure Maintenance [X] Disposal [ ] Storage
Application qualifies for administrative approval? [X] yes [ ] no

II. Operator: Texaco E&P, Inc.

Address: 205 E. Bender Hobbs, NM 88240

Contact party: Jason Wacker Phone: 505-3970484

III. Well data: Complete the data required on the reverse side of this form for each well proposed for injection. Additional sheets may be attached if necessary.

IV. Is this an expansion of an existing project? [ ] yes [X] no
If yes, give the Division order number authorizing the project ______.

V. Attach a map that identifies all wells and leases within two miles of any proposed injection well with a one-half mile radius circle drawn around each proposed injection well. This circle identifies the well's area of review.

* VI. Attach a tabulation of data on all wells of public record within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of completion, and a schematic of any plugged well illustrating all plugging detail.

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OIL CONSERVATION DIV.

VII. Attach data on the proposed operation, including:

1. Proposed average and maximum daily rate and volume of fluids to be injected;
2. Whether the system is open or closed;
3. Proposed average and maximum injection pressure;
4. Sources and an appropriate analysis of injection fluid and compatibility with the receiving formation if other than reinjected produced water; and
5. If injection is for disposal purposes into a zone not productive of oil or gas at or within one mile of the proposed well, attach a chemical analysis of the disposal zone formation water (may be measured or inferred from existing literature, studies, nearby wells, etc.).

*VIII. Attach appropriate geological data on the injection zone including appropriate lithologic detail, geological name, thickness, and depth. Give the geologic name, and depth to bottom of all underground sources of drinking water (aquifers containing waters with total dissolved solids concentrations of 10,000 mg/l or less) overlying the proposed injection zone as well as any such source known to be immediately underlying the injection interval.

IX. Describe the proposed stimulation program, if any.

* X. Attach appropriate logging and test data on the well. (If well logs have been filed with the Division they need not be resubmitted.)

* XI. Attach a chemical analysis of fresh water from two or more fresh water wells (if available and producing) within one mile of any injection or disposal well showing location of wells and dates samples were taken.

XII. Applicants for disposal wells must make an affirmative statement that they have examined available geologic and engineering data and find no evidence of open faults or any other hydrologic connection between the disposal zone and any underground source of drinking water.

XIII. Applicants must complete the "Proof of Notice" section on the reverse side of this form.

XIV. Certification

I hereby certify that the information submitted with this application is true and correct to the best of my knowledge and belief.

Name: Jason Wacker Title Production Engineer

Signature: Jason Wacker Date: 10/8/98

* If the information required under Sections VI, VIII, X, and XI above has been previously submitted, it need not be duplicated and resubmitted. Please show the date and circumstance of the earlier submittal. ______

DISTRIBUTION: Original and one copy to Santa Fe with one copy to the appropriate Division district office.

III. WELL DATA

A. The following well data must be submitted for each injection well covered by this application. The data must be both in tabular and schematic form and shall include:

(1) Lease name; Well No.; location by Section, Township, and Range; and footage location within the section.

(2) Each casing string used with its size, setting depth, sacks of cement used, hole size, top of cement, and how such top was determined.

(3) A description of the tubing to be used including its size, lining material, and setting depth.

(4) The name, model, and setting depth of the packer used or a description of any other seal system or assembly used.

Division District offices have supplies of Well Data Sheets which may be used or which may be used as models for this purpose. Applicants for several identical wells may submit a "typical data sheet" rather than submitting the data for each well.

B. The following must be submitted for each injection well covered by this application. All items must be addressed for the initial well. Responses for additional wells need be shown only when different. Information shown on schematics need not be repeated.

(1) The name of the injection formation and, if applicable, the field or pool name.

(2) The injection interval and whether it is perforated or open-hole.

(3) State if the well was drilled for injection or, if not, the original purpose of the well.

(4) Give the depths of any other perforated intervals and detail on the sacks of cement or bridge plugs used to seal off such perforations.

(5) Give the depth to and name of the next higher and next lower oil or gas zone in the area of the well, if any.

XIV. PROOF OF NOTICE

All applicants must furnish proof that a copy of the application has been furnished, by certified or registered mail, to the owner of the surface of the land on which the well is to be located and to each leasehold operator within one-half mile of the well location.

Where an application is subject to administrative approval, a proof of publication must be submitted. Such proof shall consist of a copy of the legal advertisement which was published in the county in which the well is located. The contents of such advertisement must include:

(1) The name, address, phone number, and contact party for the applicant;

(2) the intended purpose of the injection well; with the exact location of single wells or the section, township, and range location of multiple wells;

(3) the formation name and depth with expected maximum injection rates and pressures; and

(4) a notation that interested parties must file objections or requests for hearing with the Oil Conservation Division, P. O. Box 2088, Santa Fe, New Mexico 87501 within 15 days.

NO ACTION WILL BE TAKEN ON THE APPLICATION UNTIL PROPER PROOF OF NOTICE HAS BEEN SUBMITTED.

NOTICE: Surface owners or offset operators must file any objections or requests for hearing of administrative applications within 15 days from the date this application was mailed to them.

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 11848
Order No. R-10882

APPLICATION OF SANTA FE ENERGY RESOURCES, INC. FOR SALT WATER DISPOSAL, EDDY COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 8:15 a.m. on September 4, 1997, at Santa Fe, New Mexico, before Examiner David R. Catanach.

NOW, on this 24th day of September, 1997, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) The applicant, Santa Fe Energy Resources, Inc., seeks authority to utilize its Jones Canyon "4" Federal Well No. 2, located 1505 feet from the South line and 2381 feet from the East line (Unit J) of Section 4, Township 22 South, Range 24 East, NMPM, Eddy County, New Mexico, as a production/disposal well in the following manner:

> The well will be produced from the Cisco-Canyon formation, Indian Basin- Upper Pennsylvanian Associated Pool, through the perforated interval from approximately 7,950 feet to 8,300 feet. Separation of oil and water will be accomplished downhole by means of a hydrocyclone downhole separator. The oil stream will be pumped to the surface by means of a downhole production pump and water will be injected into the Devonian and Montoya formations at a depth of approximately 10,600 feet to 11,400 feet by means of a downhole injection pump.

(3) Evidence, testimony and information obtained from Division records indicate that the applicant drilled the Jones Canyon "4" Federal Well No. 2 in February, 1996, to a total depth of 8,565 feet. The well was cased and cemented as follows:

Casing Size	Setting Depth	Top of Cement
9 5/8"	1,600'	Circulated to Surface
7.0"	8,565'	Approximately 6,000'

(4) Due to water disposal limitations at its Indian Basin Central Battery, the applicant has yet to complete the aforesaid Jones Canyon "4" Federal Well No. 2 in the Indian Basin-Upper Pennsylvanian Associated Pool.

(5) The applicant proposes to deepen the Jones Canyon "4" Federal Well No. 2 to a total depth of approximately 11,400 feet and subsequently run a 4 ½ inch liner from a depth of approximately 8,500 feet to 11,300 feet. The applicant further proposes to cement the 4 ½ inch liner with 300 sacks, or a sufficient volume to circulate cement.

(6) Evidence and testimony presented indicates that wells within the Indian Basin-Upper Pennsylvanian Associated Pool typically produce at high water/oil ratios.

(7) The applicant currently utilizes submersible pumps in other producing wells which it operates in the Indian Basin-Upper Pennsylvanian Associated Pool. Applicant testified that due to the mechanical limitations of these submersible pumps, maximum fluid production from these wells is approximately 3,200 barrels per day (approximately 3,000 barrels of water and 100-200 barrels of oil per day).

(8) Utilizing the hydrocyclone downhole separator should allow the applicant to increase fluid production from the Cisco-Canyon reservoir to approximately 6,000 barrels per day, which should result in a significant increase in oil production.

(9) Applicant testified that the proposed hydrocyclone downhole separator should efficiently separate the oil and water in the production stream.

(10) Applicant further proposes to:

a) install the downhole pumps and separation equipment on 3 ½ inch internally plastic-coated tubing set in a polished bore receptacle and seal assembly at approximately 8,500 feet;

b) utilize downhole monitoring equipment to determine injection pressures and volumes; and,

c) inject fluid into the Devonian and Montoya formations at a maximum injection pressure of 5,800 psi (approximately 1,000 psi @ surface).

(11) No offset operator and/or interest owner appeared at the hearing in opposition to the proposed production/disposal well.

(12) Prior to commencing production/injection operations, the casing and liner in the subject well should be pressure-tested throughout the interval from the surface down to total depth to assure the integrity of such casing.

(13) The pressurization system should be equipped or otherwise maintained so as to limit injection pressure into the Devonian and Montoya formations to no more than 5,800 psi (1000 psi @ surface).

(14) The Director of the Division should be authorized to administratively approve an increase in the injection pressure upon a proper showing by the operator that such higher pressure will not result in migration of the injected fluid from the Devonian and Montoya formations.

(15) The operator should notify the supervisor of the Artesia district office of the Division of the date and time of the installation of production/disposal equipment and of the conductance of the mechanical integrity pressure test in order that the same may be witnessed.

(16) The operator should take all steps necessary to ensure that the injected water enters only the proposed injection interval and is not permitted to escape to other formations or onto the surface.

(17) The applicant should consult with the Santa Fe and Artesia offices of the Division to develop a plan for testing the mechanical integrity of the subject well at reasonable frequencies.

(18) Approval of the subject application will prevent the drilling of unnecessary wells and will otherwise prevent waste and protect correlative rights.

(19) The injection authority granted herein should terminate one year after the effective date of this order if the applicant has not commenced injection operations into the subject well, provided however, the Division, upon written request by the applicant, may grant an extension thereof for good cause shown.

IT IS THEREFORE ORDERED THAT:

(1) The applicant, Santa Fe Energy Resources, Inc., is hereby authorized to utilize its Jones Canyon "4" Federal Well No. 2, located 1505 feet from the South line and 2381 feet from the East line (Unit J) of Section 4, Township 22 South, Range 24 East, NMPM, Eddy County, New Mexico, as a production/disposal well in the following manner:

> The well will be produced from the Cisco-Canyon formation, Indian Basin Upper Pennsylvanian Associated Pool, through the perforated interval from approximately 7,950 feet to 8,300 feet. Separation of oil and water will be accomplished downhole by means of a hydrocyclone downhole separator. The oil stream will be pumped to the surface by means of a downhole production pump and water will be injected into the Devonian and Montoya formations at a depth of approximately 10,600 feet to 11,400 feet by means of a downhole injection pump.

PROVIDED HOWEVER THAT, the wellbore shall be deepened and equipped as proposed by the applicant at the time of the hearing. Any variation from the proposed wellbore configuration shall be submitted to the Santa Fe office of the Division for approval.

(2) Prior to commencing production/injection operations, the casing and liner in the subject well shall be pressure-tested throughout the interval from the surface down to total depth to assure the integrity of such casing.

(3) The pressurization system shall be equipped or otherwise maintained so as to limit injection pressure into the Devonian and Montoya formations to no more than 5,800 psi (1000 psi @ surface).

(4) The Director of the Division shall be authorized to administratively approve an increase in the injection pressure upon a proper showing by the operator that such higher pressure will not result in migration of the injected fluid from the Devonian and Montoya formations.

(5) The operator shall notify the supervisor of the Artesia district office of the Division of the date and time of the installation of production/disposal equipment and of the conductance of the mechanical integrity pressure test in order that the same may be witnessed.

(6) The operator shall take all steps necessary to ensure that the injected water enters only the proposed injection interval and is not permitted to escape to other formations or onto the surface.

(7) The applicant shall consult with the Santa Fe and Artesia offices of the Division to develop a plan for testing the mechanical integrity of the subject well at reasonable frequencies.

(8) The injection authority granted herein shall terminate one year after the effective date of this order if the applicant has not commenced injection operations into the subject well, provided however, the Division, upon written request by the applicant, may grant an extension thereof for good cause shown.

(9) Jurisdiction is hereby retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

WILLIAM J. LEMAY
Director

S E A L

New Mexico Oil Conservation Division – Form C-108

I. **Purpose :** Disposal

II. **Operator :** Texaco Exploration & Production, Inc.
Address : 205 E. Bender, Hobbs, New Mexico 88240
Contact Party : Jason Wacker (505) 397-0484

III. **Salt Water Disposal Well Data**
Bilbrey 30 Federal #5
Unit Letter J, 1980' FSL, 1980' FEL, Section 30, T-21-S, R-32-E
Lea County, New Mexico
The above mentioned well is currently classified as a producing oil well. It will be dually completed as a producing oil well and a saltwater disposal well. The current producing interval is 4654' – 4680' and the proposed injection interval is 5160' – 5210'. No oil or gas zones are known to exist above the production interval. Produced water from the interval 4654' – 4680' will be separated from produced oil down hole and injected into the disposal interval 5160' – 5210'. Oil, gas, and a reduced amount of water will be produced at the surface. The Bone Spring formation is the next lower oil zone in the well.

IV. This is not an expansion of an existing project.

V. **Subject Area Maps and Area of Review**
A map of the subject area, Bilbrey lease, including all wells within a 2 mile radius is attached. Also attached is a map showing the subject well's area of review (one half-mile radius).

VI. Several wells have been staked within the subject well's one half-mile area of review, but none have been spud. See attached information.

VII. See attached data on the proposed operation.

VIII. +/- 50' underground source of drinking water as per NM State Engineers Office.
5160' – 5210' (50' thick) upper Delaware. Proposed injection interval. Deep marine turbidite sandstone. These sands are not drinking water zones and in Texaco's opinion they are non-productive in this area.

IX. Acidize Delaware perfs from 5160' - 5210' (50') with 2500 gal 15% NEFE HCl and 75 ball sealers.

X. Appropriate well logs have been filed with the BLM/NMOCD.

XI. No Freshwater Wells within the Area of Review – As Per NM State Engineers Office

One Freshwater well within 1 mile

AEC #7 – Shut-In

XII. After examining available geologic and engineering data, Texaco finds no evidence of open faults, or other hydrologic connection, between the disposal zone and any underground source of drinking water.

XIII. "Proof of Notice"

XIV. Certification

III. Well Data

INJECTION WELL DATA SHEET

Texaco E&P, Inc.		Bilbrey 30 Federal		
OPERATOR		LEASE		
5	1980' FSL &1980' FEL	30	21S	32E
WELL NO.	FOOTAGE LOCATION	SECTION	TOWNSHIP	RANGE

Schematic

See Attached

Tabular Data

Surface Casing

Size 11-3/4" 42# " Cemented with 500 sx.

TOC Surface feet determined by Circ to Surf

Hole size 14-3/4"

Intermediate Casing

Size 8-5/8" 32# " Cemented with 2075 sx.

TOC Surface feet determined by Circ to Surface

Hole size 11"

Long string

Size 5-1/2" 17# " Cemented with 685 sx.

TOC 2422' feet determined by 80% Calc

Hole size 7-7/8"

Total depth 8915'

Injection interval

4910 feet to 5210 feet
(perforated or open-hole, indicate which)

Tubing size 2-7/8" lined with ____________ (material) set in a Guiberson G-6 (brand and model) packer at 4870 feet

(or describe any other casing-tubing seal).

Other Data

1. Name of the injection formation Delaware
2. Name of Field or Pool (if applicable) Lost Tank Delaware
3. Is this a new well drilled for injection? /_7 Yes /X/ No

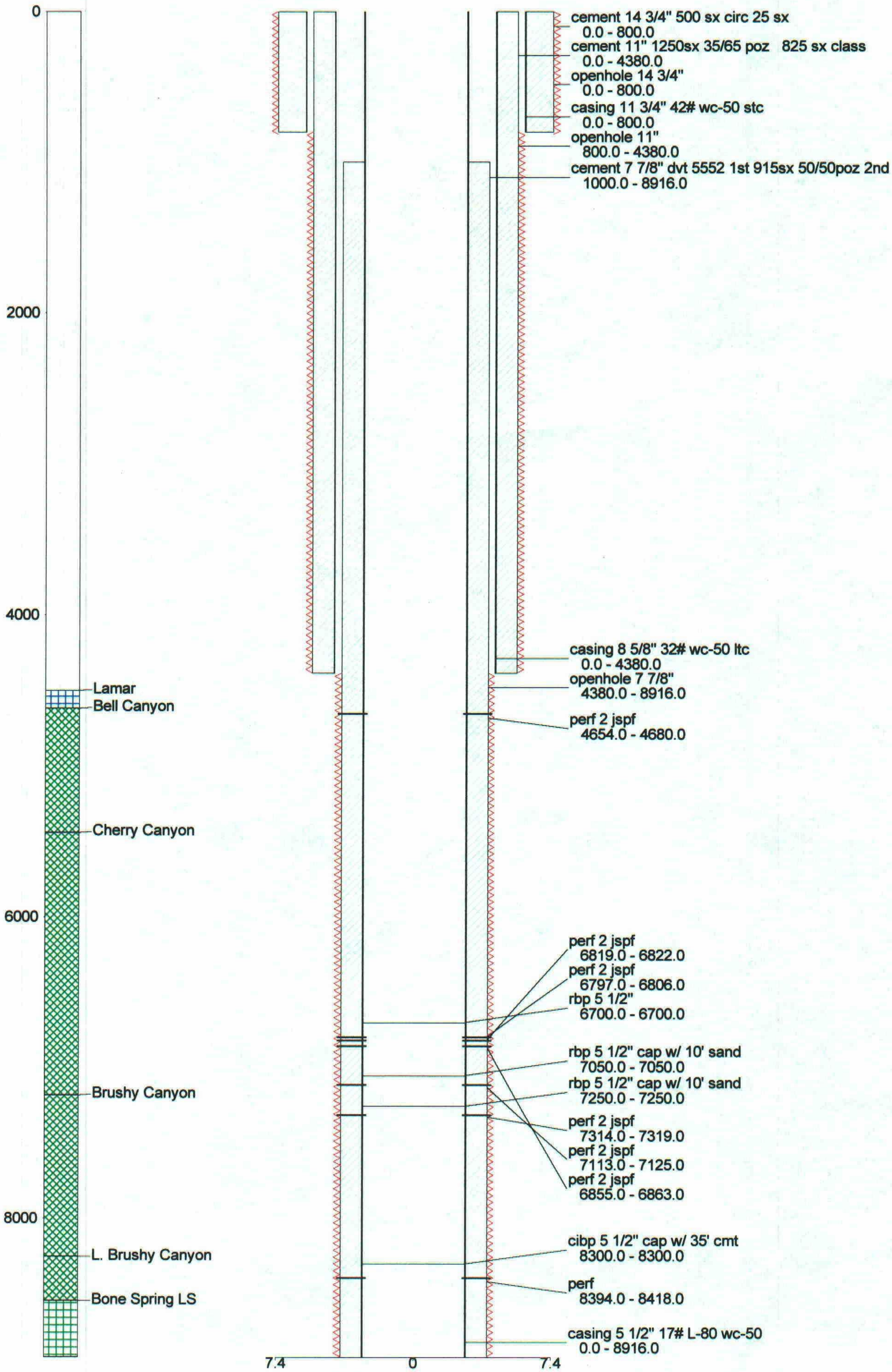
   If no, for what purpose was the well originally drilled? Oil Well

4. Has the well ever been perforated in any other zone(s)? List all such perforated intervals and give plugging detail (sacks of cement or bridge plug(s) used)

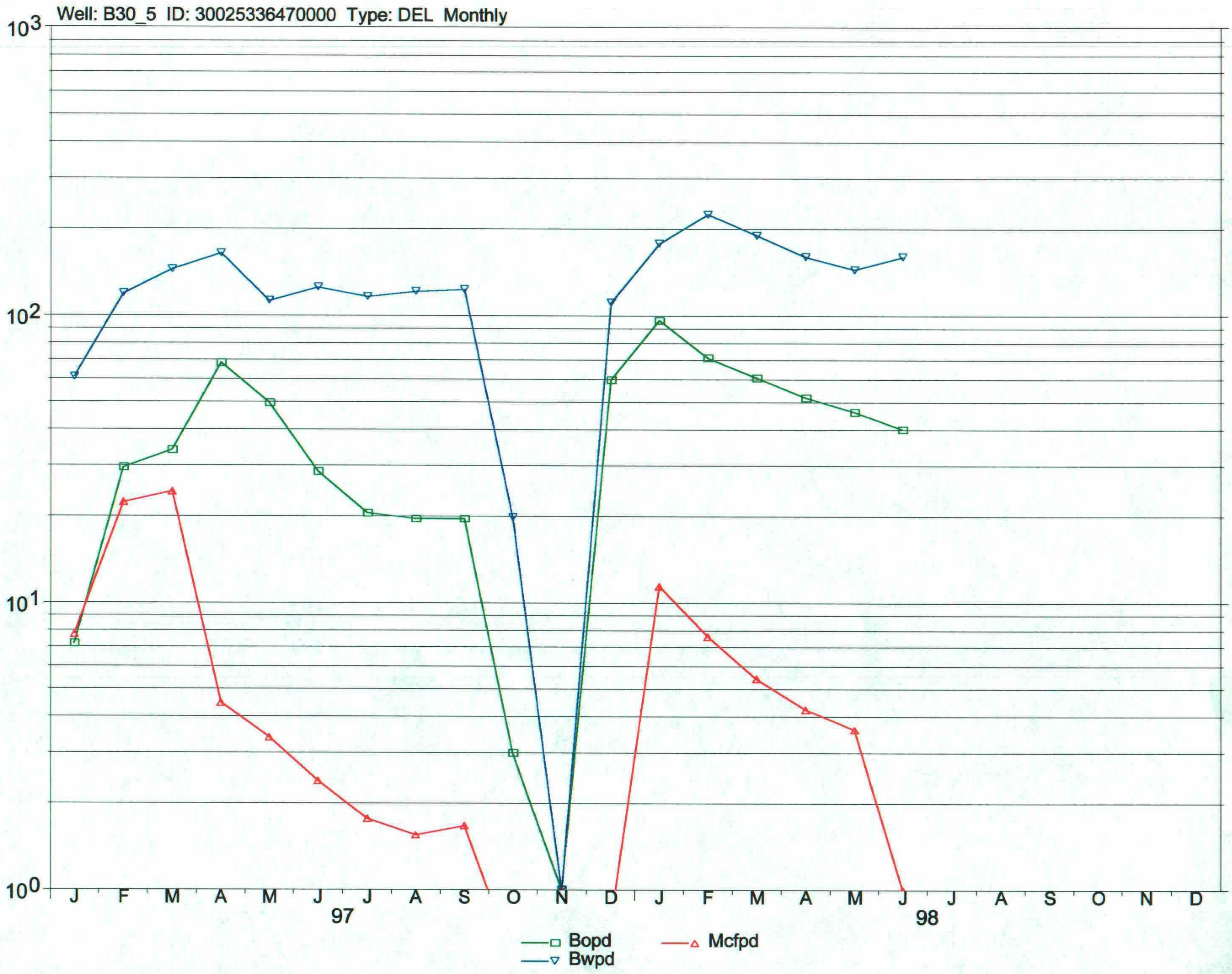
   See Attached Diagram & Well Data

5. Give the depth to and name of any overlying and/or underlying oil or gas zones (pools) in this area.

Bilbrey 30 Federal #5
1980' FSL & 1980 FEL, J-30-21S-32E
Name: B30_5 ID: 30025336470000 Type: DEL Date: 19981002
KB: 3692.0 TD: 8916.0 PBTD: 6700.0 Comp Date: 0



Bilbrey 30 Federal #5
1980' FSL & 1980' FEL, J-30-21S-32E



State : New Mexico NM Merid 21S - 32E - 30 c nw se

County: LEA Oper: TEXACO EXPL & PROD INC

Field : LOST TANK DEL Compl: 02/24/1997 D O OIL

Well: BILBREY 30 FEDERAL #5 Last Info: 05/05/1997
Ftg: 1980 fsl 1980 fel
Lat-Long by TDG: 32.447671 - 103.711397
Oper Address: PO Box 3109, Midland TX 79702 - 915/688-4606
Obj: 8850 Delaware Permit #: 10/18/1996 API: 30-025-3364700
Elev: 3692KB

Spud: 11/30/1996 Contr: Peterson Rig #: 2
TD: 8916 on 12/18/1996 PB: 7250

Elev: 3692KB FORMATION TOPS (Type: L=Log S=Sample V=True Vertical)
(Source: H=Dwights,I=IOG,T=Govt,S=Shell,U=USGS,R=NRIS
M=Munger,N=NDGS,B=Boyd,G=GDS,X=Proprietary)

Formation	Depth	Elev	T/S	Formation	Depth	Elev	T/S
Lamar	4498	-806	L H	Brushy Canyon	7181	-3489	L H
Bell Canyon	4616	-924	L H	lwr Brushy Canyon	8252	-4560	L H
Cherry Canyon	5442	-1750	L H	Bone Spring ls	8542	-4850	L H

DDC : 32.5 W Eunice (miles from the nearest city)
Casing: 11 3/4 @ 805 w/500
8 5/8 @ 4380 w/2075
5 1/2 @ 8850 w/685
Mud : 8.7# @ 8916
pH 9, FL 8
Logs : 12/18/96 Schlumberger CNL LDT GR @ 200-8885, AIT GR @ 4364-8895, BHC GR @ @4364-8895. PLAT-X
Tubing: 2 7/8 @ 7015
Perfs : 8394-8418 (lwr Brushy Canyon)
- no tretment rptd - CIBP @ 8300
7314-7319 (Brushy Canyon)
- no treatment rptd - RBP @ 7250
7113-7125 (Brushy Canyon)
w/24 holes total - acid w/700 gal 7 1/2% HCl - frac w/9870 gal 30# borate x-link gel 18300# Ottawa resin coated sd
PZone : 7113-7125 (Brushy Canyon)
IP : (Brushy Canyon 7113-7125) P 47 BOPD grav 34.2; 21 MCFGPD; 252 BWPD
Journl: 12/17/96 rig rptd on site Dec 13.
3/20/97 completed oil well.
5/5/97 added log details.

OPERATOR COPY

Form 3160-5
(June 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT –" for such proposals

SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No. NM-14331
6. If Indian, Alottee or Tribe Name
7. If Unit or CA, Agreement Designation
8. Well Name and Number BILBREY '30' FEDERAL 5
9. API Well No. 30-025-33647
10. Field and Pool, Exploratory Area LOST TANK DELAWARE
11. County or Parish, State LEA , NM

1. Type of Well: ☒ OIL WELL ☐ GAS WELL ☐ OTHER
2. Name of Operator TEXACO EXPLORATION & PRODUCTION INC.
3. Address and Telephone No. P.O. Box 2100, Denver Colorado 80201 (303)621-4851
4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
Unit Letter J : 1980 Feet From The SOUTH Line and 1980 Feet From The EAST Line Section 30 Township 21-S Range 32-E

12. Check Appropriate Box(s) To Indicate Nature of Notice, Report, or Other Data

TYPE OF SUBMISSION	TYPE OF ACTION	
☐ Notice of Intent	☐ Abandonment	☐ Change of Plans
☒ Subsequent Report	☐ Recompletion	☐ New Construction
☐ Final Abandonment Notice	☐ Plugging Back	☐ Non-Routine Fracturing
	☐ Casing Repair	☐ Water Shut-Off
	☐ Altering Casing	☐ Conversion to Injection
	☒ OTHER: SPUD,SURF, INT,PROD CSG	☐ Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log Form.)

ACCEPTED ... JAN 2 9 1997 ... acs

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work,)*.

1. PETERTSON RIG #2 SPUD 14.750 INCH HOLE @ 5:30 PM 11-30-96. DRILLED TO 800'. TD @ 5:30 AM 12-02-96.
2. RAN 18 JOINTS OF 11.750 INCH, 42#, WC-50, STC CASING SET @ 805'. RAN 6 CENTRALIZERS.
3. DOWELL CEMENTED WITH 500 SACKS CLASS C W/ 2% CACL2 (14.8 PPG, 1.34 CF/S). PLUG DOWN @ 7:30 PM 12-01-96. CIRCULATED 25 SACKS.
4. NU BOP & TESTED TO 1000#. TESTED CASING TO 1000# FOR 30 MINUTES FROM 9:30 AM TO 10:00 AM 12-03-96.
5. WOC TIME 38 HOURS FROM 7:30 PM 12-01-96 TO 9:30 AM 12-03-96.
6. DRILLING 11 INCH HOLE.
7. DRILLED 11 INCH HOLE TO 4380'. TD @ 3:45 PM 12-09-96.
8. RAN 100 JOINTS OF 8 5/8 INCH , 32# WC-50, LTC CASING SET @ 4380'. RAN 10 CENTRALIZERS.
9. DOWELL CEMENTED W/ 1250 SACKS 35/65 POZ CLASS H W/ 6% GEL, 5% SALT, 1/4# FLOCELE (12.8 PPG, 1.94 CF/S). F/B 825 SACKS CLASS H NEAT(15.6 PPG, 1.18 CF/S). PLUG DOWN @ 4:30 AM 12-10-96. CIRCULATED 150 SACKS.
10. NU BOP AND TESTED TO 1500#. TESTED CASING TO 1500# FOR 30 MINUTES FROM 6:00 PM TO 6:30 PM 12-10-96.
11. WOC TIME 13-1/2 HOURS FROM 4:30 AM 12-10-96 TO 6:00 PM 12-10-96.
12. DRILLING 7 7/8 INCH HOLE.
13. DRILLED 7 7/8 INCH HOLE TO 8916'. TD @ 2:45 AM 12-18-96.
14. RU SCHLUMBERGER. RAN GR-DLL-MSFL-SONIC AND GR-DSN-SDL-SGR-CAL FROM 8895' TO 4364'. PULLED GR-DSN TO SURFACE.
15. RAN 56 JOINTS (2448') OF 5 1/2 INCH, 17#, L-80 AND 147 JOINTS (6471') OF5 1/2", 17# WC-50, W/DV TOOL @ 5552'.
16. DOWELL CEMENTED: 585 SACKS 35/65 POZ CLASS H W/ 6% GEL, 5% SALT, 1/4# FLOCELE (12.8 PPG, 1.94 CF/S). F/B 100 SACKS CLASS H NEAT (15.6 PPG, 1.18 CF/S). PLUG DOWN @ 5:00 PM 12-20-96. DID NOT CIRCULATE CMT.
17. ND. RELEASE RIG @ 9:00 PM 12-20-96.
18. PREP TO COMPLETE.

RECEIVED JAN 9 10 00 AM '97

14. I hereby certify that the foregoing is true and correct

SIGNATURE C. P. Basham SED TITLE Eng. Assistant. DATE 1/3/97

TYPE OR PRINT NAME Sheilla D. Reed-High

(This space for Federal or State office use)

APPROVED
CONDITIONS OF APPROVAL, IF ANY: ____TITLE ____ DATE ____

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

RECEIVED

OPERATOR'S COPY

MAR 07 '97

BLM ROSWELL, NM

Form 3160-5
(June 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT --" for such proposals

SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No. NM-14331
6. If Indian, Alottee or Tribe Name
7. If Unit or CA, Agreement Designation

1. Type of Well: ☒ OIL WELL ☐ GAS WELL ☐ OTHER

8. Well Name and Number: BILBREY '30' FEDERAL 5

2. Name of Operator: TEXACO EXPLORATION & PRODUCTION INC.

3. Address and Telephone No. P.O. Box 2100, Denver Colorado 80201 (303)621-4851

9. API Well No. 30-025-33647

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
Unit Letter J : 1980 Feet From The SOUTH Line and 1980 Feet From The EAST Line Section 30 Township 21-S Range 32-E

10. Field and Pool, Exploratory Area: LOST TANK DELAWARE

11. County or Parish, State: LEA , NM

12. Check Appropriate Box(s) To Indicate Nature of Notice, Report, or Other Data

TYPE OF SUBMISSION	TYPE OF ACTION	
☐ Notice of Intent	☐ Abandonment	☐ Change of Plans
☒ Subsequent Report	☐ Recompletion	☐ New Construction
☐ Final Abandonment Notice	☐ Plugging Back	☐ Non-Routine Fracturing
	☐ Casing Repair	☐ Water Shut-Off
	☐ Altering Casing	☐ Conversion to Injection
	☒ OTHER: COMPLETION	☐ Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log Form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work,)*.

1. RU SCHLUMBERGER AND PERF'D 8394'-8418'. TIH W/NC-SN ON 2-7/8" TBG TO 8315'. RU DOWELL AND SPOT 200 GALS 7.5%, ACIDIZED W/700 GALS 7.5% AND 75 BALL SEALERS. 01-04-97.
2. LOAD HOLE W/2% KCL. RU SCHLUMBERGER & SET CIBP @8300'. TEST TO 4000 PSI. DUMP BAIL 35' CMT ON PLUG. PERF 2 JSPF @ 7314'-19'. 01-08-97.
3. RU DOWELL. BROKE DOWN PERFS W/200 GALS 7-1/2% HCL NEFE. ACIDIZED W/700 GALS 7-1/2% HCL NEFE W/10 1", 1.3 SPG BALL SEALERS. FRAC'D WELL W/10,000 GALS 30# BORATE CROSSLINKED GEL & 28,000 LBS 16/30 OTTAWA RESIN COATED SD.01-11-97
4. RAN 131-3/4" AND 78-7/8" RODS. BUILD WELL HEAD AND FLOWLINE. 01-17-97.
5. HOOK UP FLOWLINE. BUILD WELL HEAD. START PUMPING @ 1:00 P.M. 01-17-97.
6. MIRU PRIDE WELL SERVICE. TOH W/ RODS & PUMP. 01-28-97.
7. CIRC HOLE W/ 2% KCL WATER. INSTALL BOP. TOH W/ TBG. 01-29-97.
8. RU SCHLUMBERGER. SET BAKER RBP @ 7250'. TEST TO 4000 PSI. DUMP BAIL 10' SAND ON PLUG. PERF'D 7113'-25', 12' 24 HOLES. TIH W/ NC-SN ON 2-7/8" TBG TO 7015'. 01-30-97.
9. RU DOWELL. BROKE FORMATION DOWN W/200 GALS 7-1/2% HCL, NEFE. ACIDIZED W/700 GALS 7-1/2% AND 1.3 SP BALL SEALERS. FRAC'D W/9870 GALS 30# BORATE CROSSLINKED GEL & 18,300# 16/30 OTTAWA RESIN COATED SD. 02-01-97.
10. TIH W/ JTS, MUD ANCHOR, PERF SUB, SN @ 7064', 2.875" TBG. TAC @ 6911'. SET TAC AND FLANGED UP WELLHEAD. PU AND TIH W/ 2.5" X 1.75" X 25' PUMP, RODS, LINER. SPACED OUT PUMP AND LEFT WELL PUMPING TO TEST TANKS @ 6:00 P.M. 02-06-97.
11. MIRU W/S RIG. PULL RODS & PUMP. 02-17-97
12. DOWELL. FRAC'D W/11,000 GALS 35# BORATE CROSSLINKED GEL W/27740# 16/30 RESIN COATED CURABLE OTTAWA SD. 02-18-97.
13. PU 2 1/2" X 1 3/4" X 24' PUMP, RODS. LEFT WELL PUMPING TO TEST TANK. SN @ 7064'. 02-20-97.
14. PUMPED 47 BO, 252 BW, 21 MCF IN 24 HOURS. 02-24-97.

14. I hereby certify that the foregoing is true and correct

SIGNATURE C. L. Basham /SRH TITLE Eng. Assistant. DATE 2/27/97

TYPE OR PRINT NAME Sheilla D. Reed-High

(This space for Federal or State office use)

ACCEPTED FOR RECORD
David R. Glass

APPROVED
CONDITIONS OF APPROVAL, IF ANY: TITLE DATE

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

Form 3160-4
(October 1990)

UNITE STATES
DEPARTMENT THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0137
Expires: December 31, 1991

OPERATOR'S COPY

SUBMIT ORIGINAL WITH 5 COPIES

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. Lease Designation and Serial No.: NM-14331

6. If Indian, Alottee or Tribe Name:

7. If Unit or CA, Agreement Designation:

8. Well Name and Number: BILBREY 30 FEDERAL 5

9. API Well No.: 30-025-33647

10. Field and Pool, Exploaratory Area: LOST TANK DELAWARE

11. SEC., T., R., M., or BLK. and Survey or Area: Sec. 30, Township 21-S, Range 32-E

1a. Type of Well: OIL WELL ☒ GAS WELL ☐ DRY ☐ OTHER

1b. Type of Completion: NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ OTHER

2. Name of Operator: TEXACO EXPLORATION & PRODUCTION INC.

3. Address and Telephone No.: 205 E. Bender, HOBBS, NM 88240 397-0418

4. Location of Well (Report location clearly and in accordance with any State requirements.*)

At Surface
Unit Letter J : 1980 Feet From The SOUTH Line and 1980 Feet From The EAST Line

At proposed prod. zone: SAME

At Total Depth

14. Permit No.: | Date Issued:

12. County or Parish: LEA | 13. State: NM

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (Show whether DF,RT, GR, etc.)	19. Elev. Casinhead
11/30/96	12/18/96	2/20/97	GR-3680'	3680'

20. Total Depth, MD & TVD	21. Plug Back T.D., MD & TVD	22. If Multiple Compl., How Many*	23. Intervals Drilled By -->	Rotary Tools	CableTools
8916'	7250'	-		0-8916'	-

24. Producing Interval(s), Of This Completion -- Top, Bottom, Name (MD and TVD)*
~~8394'-8418'~~ (LOST TANK DELAWARE) 7113' - 7125'

25. Was Directional Survey Made: YES

26. Type Electric and Other Logs Run
GR-DLL-MSFL-SONIC; GR-DSN-SDL-SGR-CAL; GR-DSN

27. Was Well Cored: NO

28. CASING RECORD (Report all Strings set in well)

CASING SIZE & GRADE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENT RECORD	AMOUNT PULLED
WC50, 11 3/4	42#	805'	14 3/4"	500 SX, CIRC 25	
WC50, 8 5/8"	32#	4380'	11"	2075 SX, CIRC 150	
WC50, 5 1/2"	17#	8850'	7 7/8"	685 SX, CIRC 0	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
2 7/8"	7015'	-

31. Perforation record (interval, size, and number)
8394'-8418' - SET CIBP @ 8300', CAP W/ 35' CMT
7314'-7319' - SET RBP @ 7250', CAP W/ 10' SAND
7113'-7125' (12 NET FT, 24 HOLES)

32. ACID, SHOT, FRACTURE, CEMENT, SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
7113'-7125'	ACID - 700 GALS 7 1/2% HCL
7113'-7125'	FRAC - 9870 G 30# BORATE X-LINK GEL
	18300# OTTAWA RESIN COATED SAND

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping - size and type pump)	Well Status (Prod. or Shut-in)
1/17/97	PUMPING - 2 1/2" X 1.75 X 20'	PROD.

Date of Test	Hours tested	Choke Size	Prod'n For Test Period	Oil - Bbl.	Gas - MCF	Water - Bbl.	Gas - Oil Ratio
2/24/97	24			47	21	252	447

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil - Bbl.	Gas - MCF	Water - Bbl.	Oil Gravity - API -(Corr.)
						34.2

34. Disposition of Gas (Sold, used for fuel, vented, etc.): FLARING

Test Witnessed By: JOHNSTON

35. List of Attachments: DEVIATION SURVEY

ACCEPTED FOR RECORD
David R. Glass
1997

36. I hereby certify that the foregoing is true and correct

SIGNATURE Monte C. Duncan TITLE Engr Asst DATE 3/3/97

TYPE OR PRINT NAME Monte C. Duncan

DeSoto/Nichols 12-93 ver 1.0

37. SUMMARY OF POROUS ZONES: (Show all important zones of porosity and contents therof; cored intervals; and all drill-stem, tests including depth interval tested, cushion used, time tool open, flowing and shut-in pressures, and recoveries):

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS,ETC.
BELL CANYON	4650'	4686'	SAND
L. CHERRY CANYO	6793'	7172'	SAND, SHALE
BRUSHY CANYON	7181'	8527'	SAND, SHALE, LIMESTONE

38. GEOLOGIC MARKERS

NAME	TOP	
	MEAS. DEPTH	TRUE VERT. DEPTH
LAMAR	4498'	
BELL CANYON	4616'	
CHERRY CANYON	5442'	
BRUSHY CANYON	7181'	
L. BRUSHY CANYO	8252'	
BONE SPRING LS	8542'	

Form 3160-5
(June 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT --" for such proposals

SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No: NM-14331
6. If Indian, Alottee or Tribe Name
7. If Unit or CA, Agreement Designation
8. Well Name and Number: BILBREY '30' FEDERAL 5
9. API Well No: 30-025-33647
10. Field and Pool, Exploratory Area: LOST TANK DELAWARE
11. County or Parish, State: LEA , NM

1. Type of Well: ☒ OIL WELL ☐ GAS WELL ☐ OTHER
2. Name of Operator: TEXACO EXPLORATION & PRODUCTION INC.
3. Address and Telephone No: P.O. Box 2100, Denver Colorado 80201 (303)621-4851
4. Location of Well (Footage, Sec., T., R., M., or Survey Description)

Unit Letter J : 1980 Feet From The SOUTH Line and 1980 Feet From The EAST Line Section 30 Township 21-S Range 32-E

12. Check Appropriate Box(s) To Indicate Nature of Notice, Report, or Other Data

TYPE OF SUBMISSION	TYPE OF ACTION	
☐ Notice of Intent	☐ Abandonment	☐ Change of Plans
☒ Subsequent Report	☐ Recompletion	☐ New Construction
☐ Final Abandonment Notice	☐ Plugging Back	☐ Non-Routine Fracturing
	☐ Casing Repair	☐ Water Shut-Off
	☐ Altering Casing	☐ Conversion to Injection
	☒ OTHER: COMPLETION	☐ Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log Form.)

1997
acs

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work,)*.

1. RU SCHLUMBERGER. RIH W/ BAKER WLS/TBG RET BP. CORRELATE F/DEPTH, SET PLUG @ 7050'. TESTED PLUG 4000 PSI. RIH W/ DUMP BAILER, DUMP 10' SAND ON PLUG. POH. RIH W/4" CSG GUNS. PERFORATE AS FOLLOWS: 6797'-6806', 6819'-6822', 6855'-6863', WITH 2 JSPF. 47 HOLES.
2. RU DOWELL. ACIDIZED THE LOWER CHERRY CANYON W/900 GALS 7 1/2% NEFE HCL. FRAC W/11,000 GALS 35# BORATE CROSSLINKED GEL AND 28,000 16/30 OTTAWA RCS. 03-08-97.
3. STRAP TBG IN HOLE TO 6970'. TOH. P/U MUD ANCHOR & SN. TIH W/223 JTS TBG, N/D BOP. SET TAC. NU WELLHEAD. SDFN. BTM OF MUD ANCHOR @ 6925', SN @ 6893'. 03-12-97.
4. RAN 2 1/2" X 1.75" X 20' PUMP, RODS, 03-13-97.
5. MIRU YALE E. KEY W/S RIG. TOH W/ RODS & PUMP. 03-25-97.
6. RU SCHLUMBERGER. RIH W/ BAKER RBP. SET PLUG @ 6700'. RAN GR/CCL STRIP LOG F/5600'-4600'. PERFORATED AS FOLLOWS: 4654'-4680' W/ 2 JSPF. 53 HOLES. RD SCHLUMBERGER. TIH W/SN & 147 JTS, 2-7/8" TBG. LANDED TBG @ 4552'. 03-26-97.
7. RU DOWELL. ACIDIZED THE BELL CANYON W/2000 GALS 7-1/2% HCL NEFE. 03-27-97.
8. P/U 2-1/2" X 1-3/4" X 20' PUMP. RAN RODS. SN @ 4758'. 03-29-97.
9. OPT: PUMPED 123 BO, 149 BW, 18 MCF. 04-02-97.

RECEIVED
APR 21 '97
BLM
ROSWELL, NM

14. I hereby certify that the foregoing is true and correct

SIGNATURE C.P. Basham /SRH TITLE Eng. Assistant. DATE 4/8/97

TYPE OR PRINT NAME Sheilla D. Reed-High

(This space for Federal or State office use)

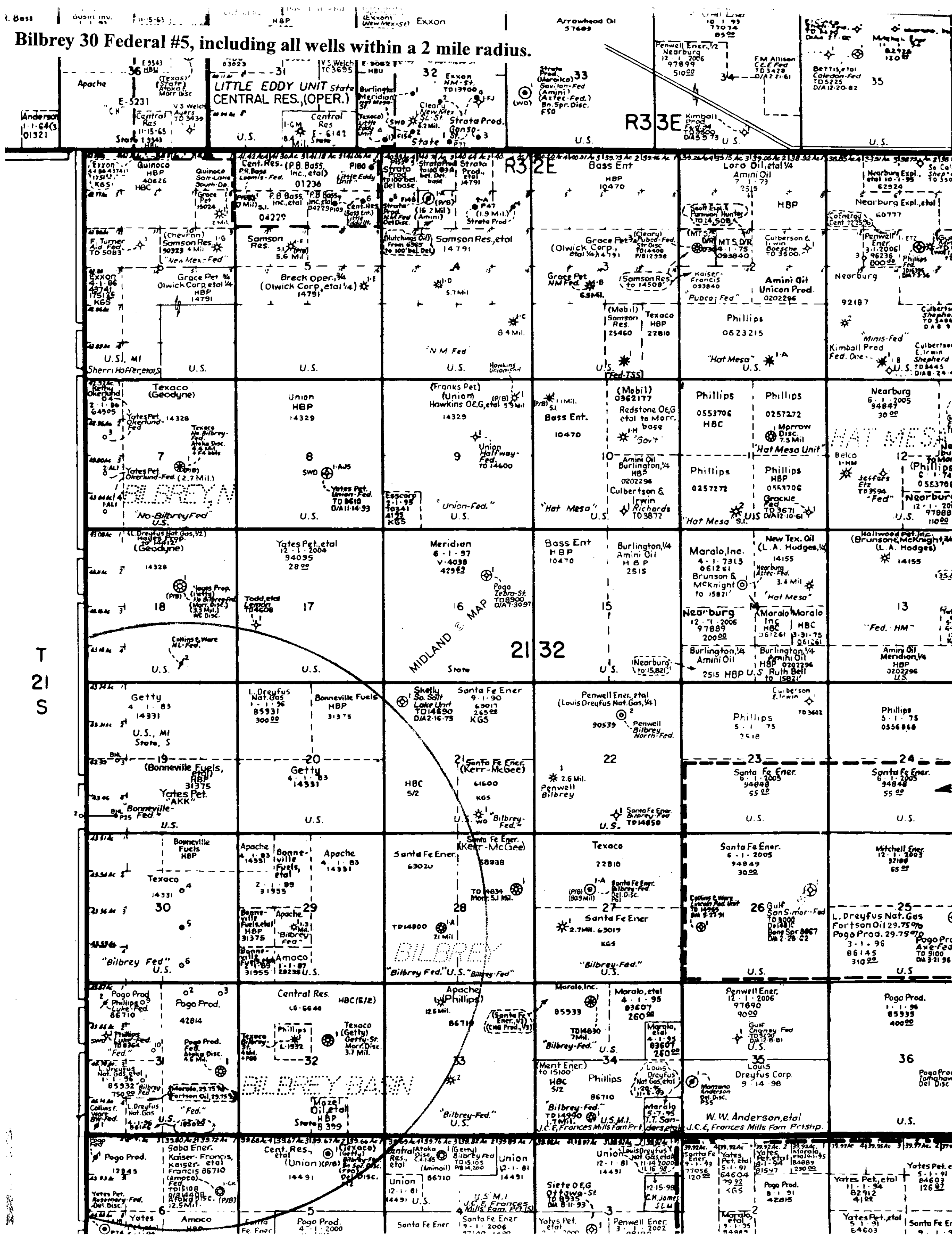
APPROVED
CONDITIONS OF APPROVAL, IF ANY: _____TITLE_____ DATE_____

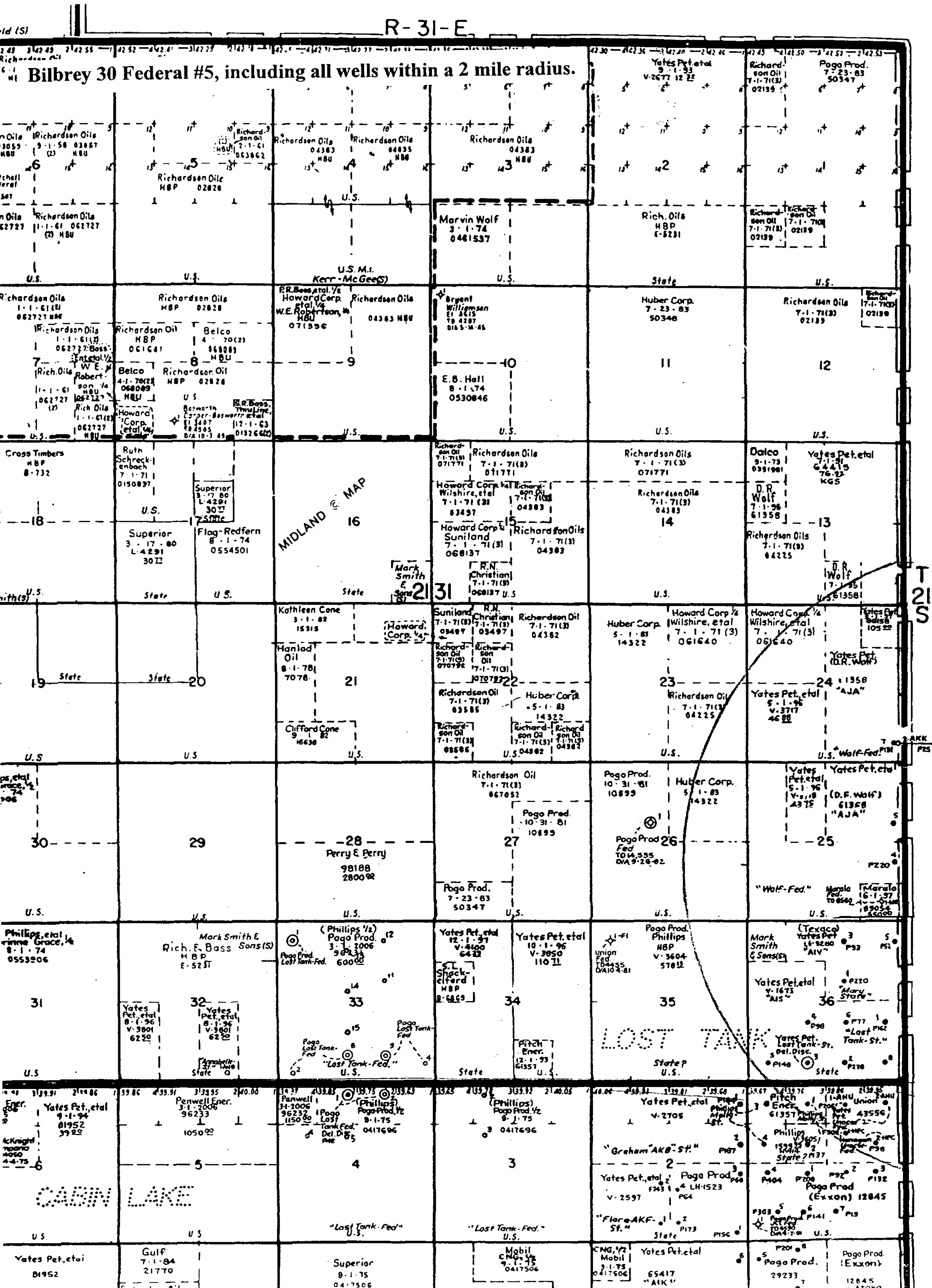
Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

DeSoto/Nichols 10-94 ver 2.0

V. Area of Review

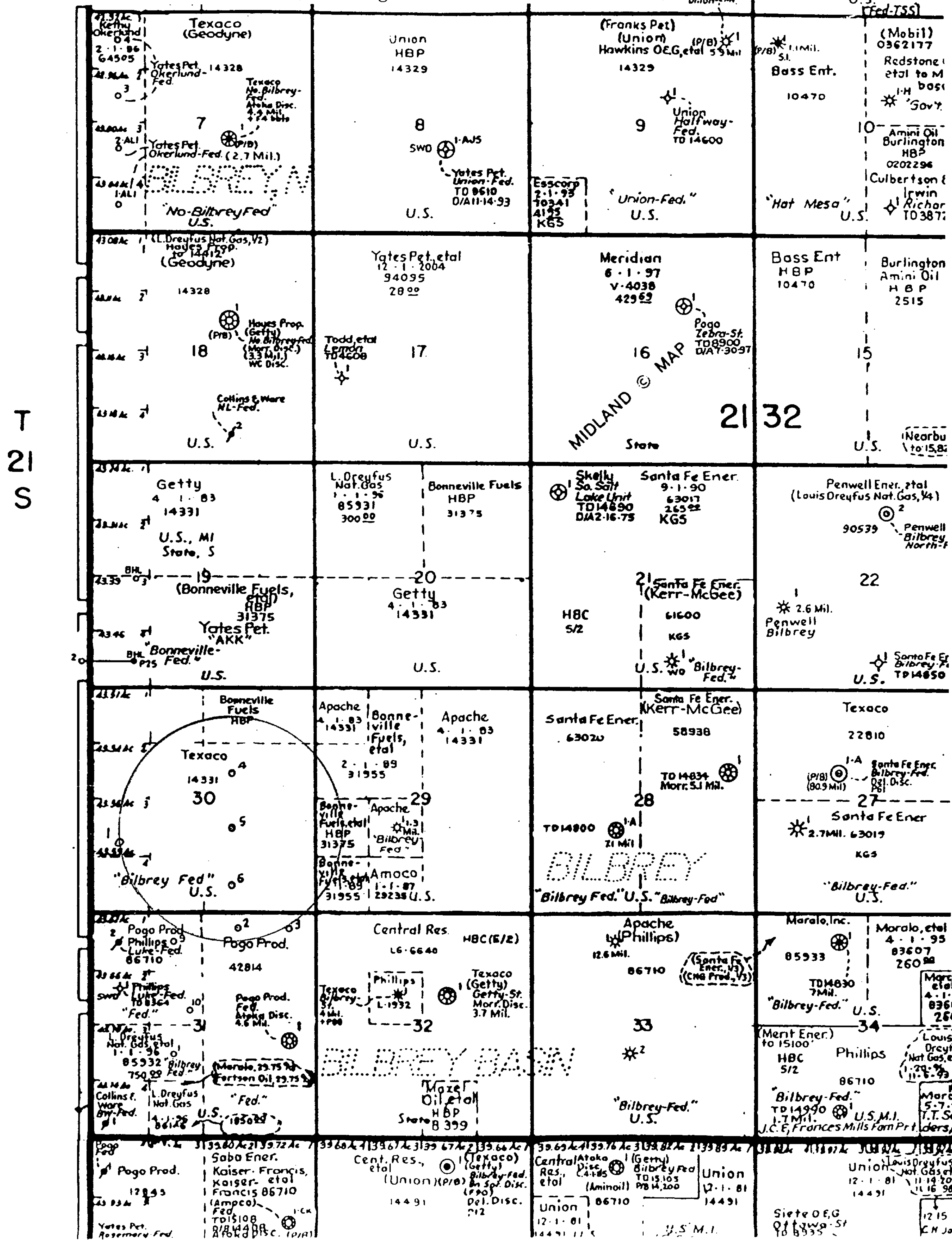
Bilbrey 30 Federal #5, including all wells within a 2 mile radius.





LEA, Southwest

Bilbrey 30 Federal #5 Area of Review, including all wells within a 1/2 mile radius.



VI. Well Data Within Area of Review

```
================================================================================
State : New Mexico       NM Merid  21S - 32E - 30  sw nw sw

County: LEA                     Oper: TEXACO EXPL & PROD INC

Field : LOST TANK DEL                      Compl:                D
================================================================================
Well: BILBREY 30 FEDERAL #1                            Last Info: 09/10/1996
Ftg:  1650 fsl 560 fwl
Lat-Long by TDG:   32.446716 - 103.720642
Oper Address: PO Box 3109, Midland TX 79702 - 915/688-4606
Obj:  8600  Delaware        Permit #:        08/21/1996  API: 30-025-3171100
                                              Elev:  3701GR
================================================================================
Spud:
================================================================================
DDC   :  32.5 W     Eunice (miles from the nearest city)
Notes : (Permit extended, originally approved 8/21/92)
LocCom: 9/15/92 (distance chngd from 3.5 W of Eunice) per approved intent.
        9/10/96 has not spud.
```

==

State : New Mexico   NM Merid 21S - 32E - 30 c sw ne

County: LEA   Oper: TEXACO EXPL & PROD INC

Field : LOST TANK DEL   Compl: D

==

Well: BILBREY 30 FEDERAL #4   Last Info: 11/06/1996
Ftg: 1980 fnl 1980 fel
Lat-Long by TDG: 32.451346 - 103.711401
Oper Address: PO Box 3109, Midland TX 79702 - 915/688-4606
Obj: 8850 Delaware   Permit #:   10/18/1996 API: 30-025-3366900
Elev: 3661GR

==

Spud:

==

DDC   : 32.5 W   Eunice (miles from the nearest city)

State : New Mexico NM Merid 21S - 32E - 30 c sw se

County: LEA Oper: TEXACO EXPL & PROD INC

Field : LOST TANK DEL Compl: D

Well: BILBREY 30 FEDERAL #6 Last Info: 10/29/1996
Ftg: 660 fsl 1980 fel
Lat-Long by TDG: 32.444042 - 103.711393
Oper Address: PO Box 3109, Midland TX 79702 - 915/688-4606
Obj: 8850 Delaware Permit #: 10/18/1996 API: 30-025-3364800
Elev: 3709GR

Spud:

DDC : 32.5 W Eunice (miles from the nearest city)

State : New Mexico NM Merid 21S - 32E - 31 ne nw ne

County: LEA Oper: POGO PRODUCING CO

Field : LIVINGSTON RIDGE SE DEL Compl: D

Well: FEDERAL 31 #2 Last Info: 03/10/1997
Ftg: 330 fnl 1880 fel
Lat-Long by TDG: 32.441320 - 103.711060
Oper Address: PO Box 10340, Midland TX 79702-7340 - 915/682-6822
Obj: 8800 Delaware Permit #: 01/17/1997 API: 30-025-3316100
Elev: 3684GR

Spud:

DDC : 30E Carlsbad (miles from the nearest city)
Notes : (Permit extended, originally approved 10/17/95)

===

State : New Mexico   NM Merid 21S - 32E - 31 n/2 ne ne

County: LEA   Oper: POGO PRODUCING CO

Field : LIVINGSTON RIDGE SE DEL   Compl: D

===

Well: FEDERAL 31 #3   Last Info: 03/10/1997
Ftg: 330 fnl 660 fel
Lat-Long by TDG: 32.441330 - 103.707110
Oper Address: PO Box 10340, Midland TX 79702-7340 - 915/682-6822
Obj: 8800 Delaware   Permit #:   01/17/1997 API: 30-025-3316200
                                             Elev: 3705GR

===

Spud:

===

DDC   :   30E   Carlsbad (miles from the nearest city)
Notes : (Permit extended, originally approved 10/20/95)

VII. Data on Proposed Operation

Bilbrey 30 Federal #5
1980' FSL & 1980' FEL, J-30-21S-32E
Lea County, New Mexico

Triple Action Pump Installation

Well Data

Tubing:	2-7/8"	Casing:	2488' of 5-1/2", 17#, L-80 & 6471' of 5-1/2", 17#, WC-50		
TD:	8916'	PBTD:	6700'	Elevation:	3680' GR 11.8' KB

RBP @ 6700'
RBP @ 7050' with 10' sand on top
RBP @ 7250' with 10' sand on top
CIBP @ 8300' with 35' cement on top

Open Perforations:
Delaware 4554' – 4680' w/ 2 spf

Plugged Back Perforations:
Delaware 6197' – 6806', 6819' – 6822', 6855' – 6863', & 7314' – 7319', 8394' – 8418' w/ 2 spf

Procedure

1. TOH with pump & rods. Call Unichem, Jerry White, and Axelson, John Dimock, prior to getting pump out of hole. Inspect pump and rods for scale and paraffin, collect samples.
2. TIH to +/- 5500' to check for fill. Strap & Scanalog out with 3-1/2" MHMA. Dump 10' of sand on top of RBP at 6700'.
3. Perforate injection interval 5160' – 5210' with 1 spf.
4. TIH with 5-1/2" 17# treating packer on 2-7/8" production tubing. Set packer at +/- 5100'. Establish a rate into perfs with 2% KCl water. Acidize Delaware perfs (5160' – 5210') with 2500 gal 15% NEFE HCl & 75 ball sealers.
5. Swab well back to neutral pH. Catch water sample and send to Unichem for analysis. Run step rate injection test. TOH with packer.
6. TIH with Triple Action Pumping System (similar to Dual Action Pumping System) and production packer. Set production packer with check valve at +/- 4870'.
7. Return well to production. Injection will be through a closed system. Average injection rate will be 140 BWPD and maximum injection rate will be 300 BWPD. Average injection pressure will be 2500 psig bottomhole and maximum injection pressure will be 3165 psig bottomhole. RD pulling unit. Have Unichem treat for corrosion & paraffin.

UNICHEM

A Division of BJ Services Company

Lab Test No : 21660

Texaco

Sample Date : 10/6/98
Lab Date In : 10/8/98
Lab Date Out : 10/14/98

Water Analysis

Listed below please find water analysis report from : ~~Pilsbury~~ Bilbrey #30-5

Specific Gravity :		1.131
Total Dissolved Solids :		183977
pH :		5.75
Conductivity	(µmhos):	
Ionic Strength :		3.557
Cations:		mg/l
Calcium	(Ca^{++}):	10400
Magnesium	(Mg^{++}):	1944
Sodium	(Na^{+}):	57846
Iron	(Fe^{++}):	7.38
Dissolved Iron	(Fe^{++}):	
Barium	(Ba^{++}):	
Strontium	(Sr):	
Manganese	(Mn^{++}):	2.72
Resistivity :		
Anions:		
Bicarbonate	(HCO_3^{-}):	37
Carbonate	(CO_3^{--}):	
Hydroxide	(OH^{-}):	0
Sulfate	(SO_4^{--}):	1730
Chloride	(Cl^{-}):	112000
Gases:		ppm
Carbon Dioxide	(CO_2):	185.00
Hydrogen Sulfide	(H_2S):	0.00
Oxygen	(O_2):	

Scale Index (positive value indicates scale tendency) a blank indicates some tests were not run

Temperature		CaCO3 SI	CaSO4 SI
86F	30.0C	-0.79	12.74
104F	40.0C	-0.53	12.74
122F	50.0C	-0.22	12.78
140F	60.0C	0.14	12.70
158F	70.0C	0.53	12.67
176F	80.0C	0.96	12.52

Comments :

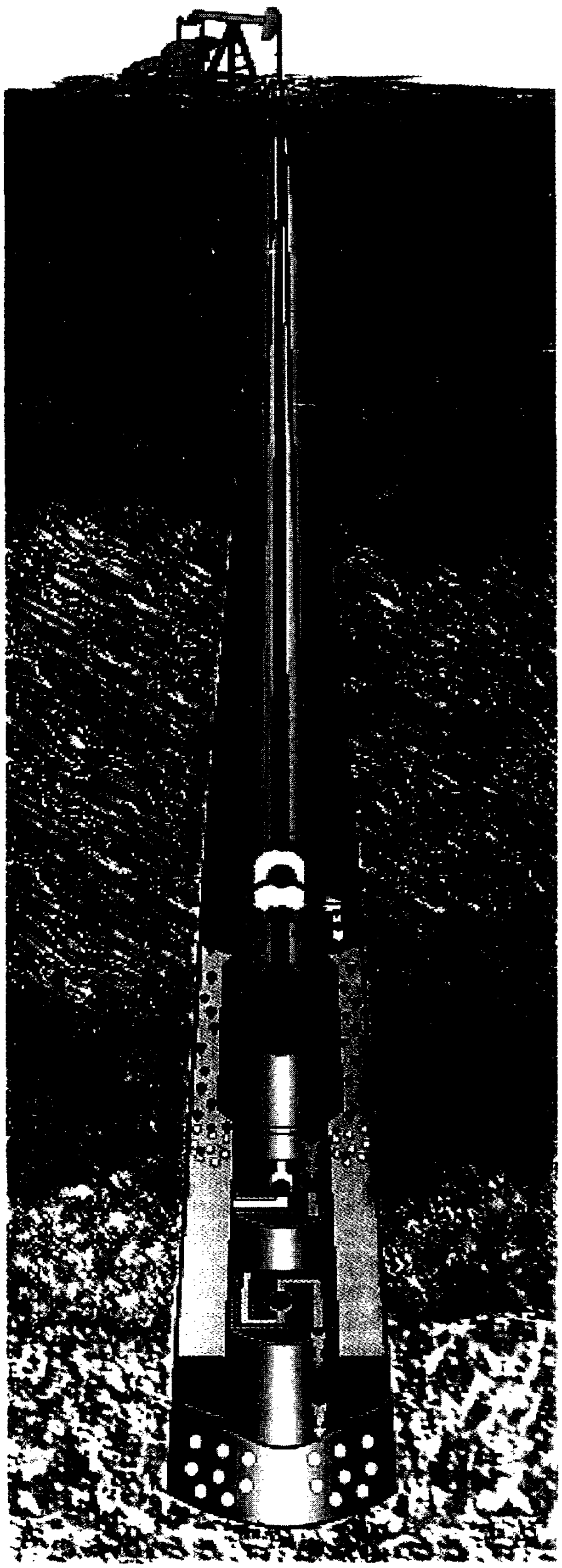
If you have any questions or require further information, please contact us.
Sincerely,

Laboratory Technician

cc: Jerry White
Jay Brown

P.O. Box 61427 • Midland, TX 79711 • 4312 S. County Rd. 1298, Midland, TX 79765
Office: (915) 563-0241 • Fax: (915) 563-0243

D.A.P.S.

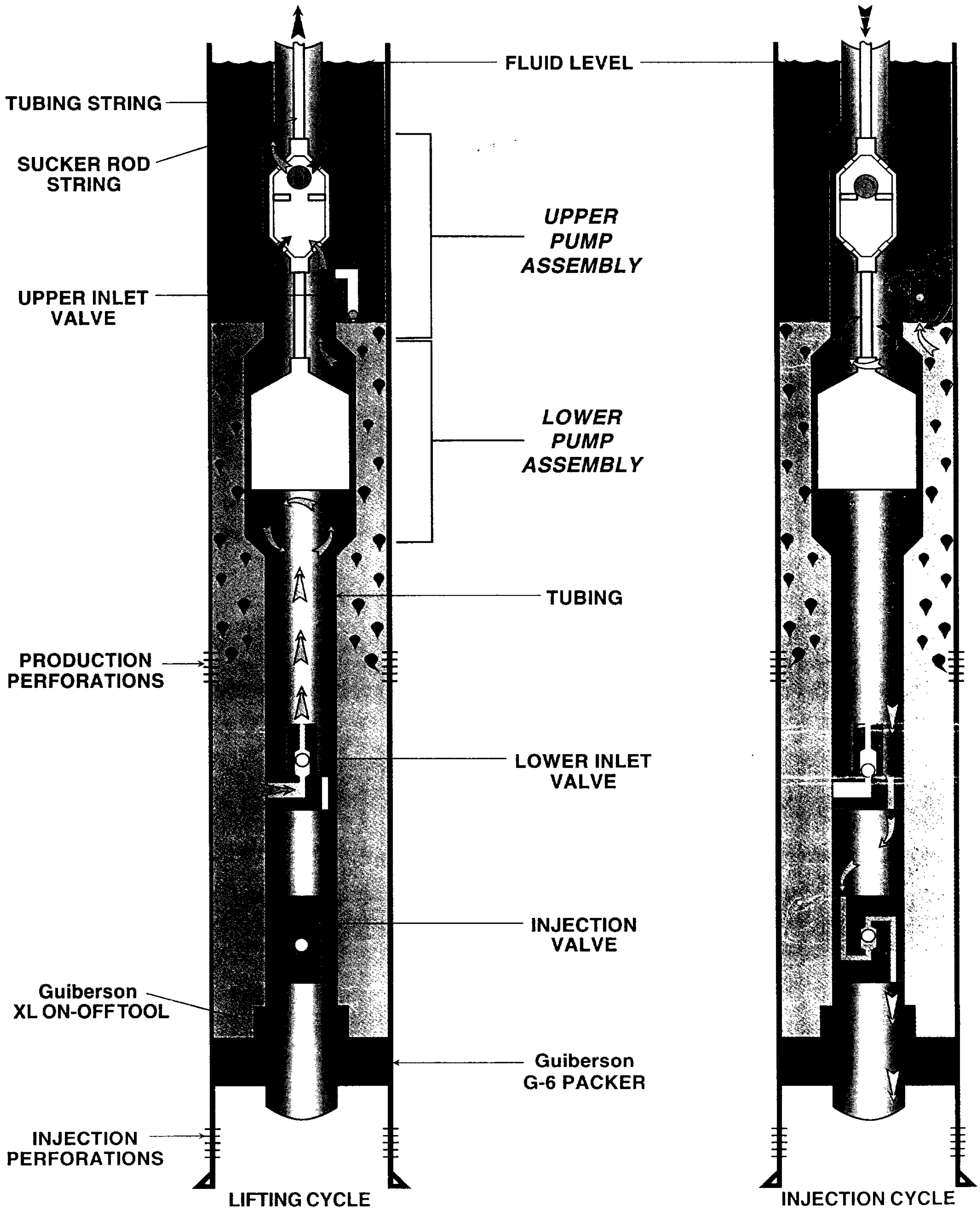


DUAL ACTION PUMPING SYSTEM

AN ENGINEERED SOLUTION FOR A ROD PUMPING SYSTEM TO PRODUCE OIL AND WATER FROM THE ANNULUS ON THE UPSTROKE WHILE INJECTING WATER ON THE DOWNSTROKE USING GRAVITY SEGREGATION

Dresser Oil Tools | DRESSER

OPERATION OF THE DUAL ACTION PUMPING SYSTEM



COST REDUCTIONS WITH THE DUAL ACTION PUMPING SYSTEM

Special engineering design

Reduce water handling cost, including lifting, treating and disposal.

Increase oil production through greater withdrawal from the formation.

Reduce energy consumption required to lift fluid.

Increase the life of rods and tubing through slower strokes per minute.

Avoid or postpone costly forms of artificial lift.

Developed through a joint effort between Texaco and Dresser Oil Tools.

Consists of two rod pumps, insert and/or tubing type.

Requires only one rod string, one tubing string.

Separate intake valves for each pump.

Pump assemblies are connected using an on-off tool.

D.A.P.S. will lift 18-30% of total fluid in well bore to surface.

Top pump lifts oil and some water on each stroke.

D.A.P.S. will inject 70-82% of water to disposal zone.

Lower pump lifts fluid to the surface and injects water downhole.

Producing and disposal zones are separated utilizing a packer.

Injection pressure is generated by rod weight and fluid weight.

Unique rod design program is utilized to insure rod compression is avoided.

BEFORE AND AFTER

FIELD	INSTALL DATE	BARRELS PER DAY				
		OIL BEFORE	OIL AFTER	WATER BEFORE	WATER AFTER	WATER INJECTION
East Texas	Oct-95	3	10	184	126	392
Carlisle	Jun-96	14	35	221	151	881
East Texas	Sep-96	7	18	269	156	487
Salem	Sep-96	8	8	700	193	507
Chauvin	Feb-97	25	32	250	25	265
RMOTC	Feb-97	5	10	190	38	190
Parkman	Mar-97	30	44	253	120	377
Valley View	Mar-97	25	28	616	189	629
Provost	Mar-97	25	31	226	19	264
Drayton Valley	May-97	75	95	517	0	285
Grande Prairie	May-97	27	28	932	179	851
Utikuma	Jun-97	8	10	451	63	210
TOTAL		252	349	4809	1259	5338
AVERAGE		19	27	370	97	411

Dresser Oil Tools | DRESSER

P.O. BOX 2427 • LONGVIEW, TEXAS 75606, USA
110 INDUSTRIAL BOULEVARD • LONGVIEW, TEXAS 75602
Telephone: (903) 757-6650 • Fax: (903) 234-3475 • Telex: 735-440

SPE 38790

Dual Injection and Lifting Systems: Rod Pumps

Lon Stuebinger, SPE, and Kevin Bowlin, SPE, Texaco, Jonathan Wright,Talisman Energy, and Mike Poythress, SPE, and Brock Watson SPE, Dresser Oil Tools, Div of Dresser Industries, Inc.

Abstract

In 1994 Texaco personnel viewed chemicals as the primary means to reduce water handling costs. They recognized from downhole videos that oil and water remain separated in the tubing-casing annulus. Capitalizing on this revelation of "gravity segregation," they conceptualized a dual-ported, dual plunger rod pump to produce oil and water from the annulus on the upstroke while injecting water on the downstroke.

Texaco and Dresser jointly developed this pump and named it the Dual Action Pumping System (DAPS). In January 1995, the first generation prototype was installed. It verified the technical and economic feasibility of this new technology. It substantially increased production while simultaneously reducing power requirements. A second generation prototype was developed to improve the valve design. It has continued to function without problems since its installation in October 1995. Tests in a Rocky Mountain Oilfield Testing Center well and several Talisman wells have further demonstrated that this will be a unique, new tool for the oil industry.

This paper will both explain how DAPS works and describe some of the early testing results. Work is continuing to improve the performance predictions. Tests have shown it to be an inexpensive technology that can reduce lifting costs and thereby increase and/or accelerate reserves recovery when the right conditions exist. While many potential applications or benefits of DAPS have been identified, these can generally be classified in three categories:

- Increase oil production
- Reduce water handling costs
- Reduce potential investment costs

Introduction

In 1993, many of Texaco's oil fields and wells were rapidly becoming uneconomic to produce because of excessive water production. Texaco's Exploration and Production Technology Division (EPTD) was requested to evaluate ways to manage excessive water production. This was conceived largely as a concerted attempt to use chemicals or cement to shut off excessive water. A surprising new option became apparent.

Part of the process was to conduct a literature search and monitor industry activity in this arena. This monitoring revealed was that it is possible to utilize pumping units for tasks such as downhole injection[1], surface pumping, gas compression, and other purposes. The scope of the study also envisioned improved diagnostic procedures. One of the diagnostic tools evaluated by EPTD was the downhole video. Tapes provided by Halliburton Energy Services[2] showed their tool had potential to qualitatively determine which perforations produce the most oil. With somewhat more difficulty, it appeared that perforations producing excessive amounts of water could also be identified. Texaco ran a downhole video in one of its wells that was equipped with a pumping unit, to test this latter theory.

Downhole Gravity Segregation.

Again, it was noticed from this video that the oil droplets were distinctly separate from the water that was being produced. This is unlike the murky mixture of oil and water typically seen at the surface. In fact, these distinct oil droplets literally squirted into the wellbore with each stroke of the pump. The rising oil droplets looked like the oil in a lava lamp. From this it was recognized that oil and water are typically separated by gravity segregation in the wellbore until they are mixed together by the pump. In retrospect, we realized that there is other evidence of this phenomenon. Consider a conventional rod pump in a high water-cut well that is pumping below the producing perforations. After it has been off production for several days, it may take hours or days before it starts producing oil again. This occurs because the oil has collected at the top of the annulus. The water in the column below the oil must be produced before the interface of the oil and water is lowered to the pump intake. This is shown in Fig. 1.

The idea of the Dual Action Pumping System (DAPS) was born by connecting these concepts: 1) the need to reduce excessive water production; 2) the ability of pumping units to inject water; and, 3) the segregated state of water and oil before it goes into the pump. Texaco EPTD collaborated with Dresser and the first generation prototype of DAPS was installed in a Texas field nine months later.

East Texas Field

To prove this visionary concept, the first DAPS prototype was designed and patented (#5,497,832). It used conventional pump parts and a couple of specialty parts that were made in a welder's shop. This pump design incorporated dual intakes to take advantage of the gravity segregation in the casing. Both the upper and lower intakes on this first pump consisted of several sets of valves external to the tubing. These balls and seats were installed in 1 1/4" four piece traveling valve cages, which were mounted to lugs welded to the side of the tubing subs. The upper pump's discharge valve was located at the top of the plunger and installed in a standard open top plunger cage. The discharge on the lower pump consisted of a spring loaded cage with a ball and seat assembly inside. This cage was turned upside down so that the spring resisted the gravity forces on the ball. This kept it on the seat when not discharging.

Texaco's First Test.

Texaco decided to deploy the first test in the East Texas field. The East Texas field has unique field rules with maximum allowable water production rates which made the application attractive. With a 300 barrel per day limit on water, oil production is restricted. Using the Dual Action Pump, it was envisioned that the fluid level in wells could be drawn down without exceeding the 300 barrel limit on the water. It was deemed possible to separate the oil from the water and only lift 18 to 30% of the fluid that the pump was handling. If possible, this would enable us to increase the oil production as we would be withdrawing more fluid from the formation. Since the water was re-injected back into the same reservoir, the water in effect never leaves the reservoir.

The first pump was installed on January 20, 1995, on J. M. Dickson #17 in the Woodbine Sand. The existing producing interval was not changed. The well had to be cleaned out in order to expose old perforations that were going to be used for injection. The injection interval was also in the Woodbine beneath an impermeable shale barrier. Surface testing performed as predicted from the IPR curve and the test appeared to be validated. Production values before and after the installation are shown in **Table 1**.

Within a couple of weeks, oil production rates started falling. This indicated that the injection volume was decreasing. The pump was pulled on February 20, 1995 to investigate the problem. When disassembled in the shop; it was noted that the upper pump's discharge valve had a slow leak. The lower pump's discharge valve, in the spring loaded cage, was pitted and also leaked. The pump was repaired, delivered to the well and rerun that same day. Production rates were re-established as before. On April 11, 1995, the production once again began to fall. It was decided that a design change in the lower valve was needed. Engineering departments of both companies began to work on this task. Since the valve had to be re-designed, a goal was also set to streamline the entire lower valve assembly. This was accomplished by eliminating the spring and moving the external valves to the inside of the lower valve assembly.

The pump was left in the hole until the new, and current, lower valve assembly (patent pending) was developed. It was pulled on October 20, 1995. When the pump was torn down, the lower discharge valve was again found to be pitted and leaking. The new lower valve design was then installed on the pump and it was taken back to the well site. Due to packer problems, the well was not put back on production until November 1, 1995. After 18 months, the pump is still pumping satisfactorily and has not required further service.

Prior to installing the Dual Action Pump into this well, the well was producing with a 2 1/4" tubing pump at 9.5 strokes per minute and a 54" stroke. The established production was 3 bopd and 184 bwpd. The Dual Action Pump was installed with a 2 1/4" upper pump and 2 3/4" lower pump. Unit speed was then increased in increments to achieve higher volumes.

Confirming the results.

A second installation of DAPS in the East Texas field had results similar to the original Texaco well. It was run for Chevron in September 1996. Before the pump was installed, the daily production was 7 bopd and 269 bwpd. The unit was running with a 54" stroke at 14 strokes per minute with a 2 1/4" bore pump. Just before the DAPS was installed, the unit was slowed to 8 stokes per minute. Production fell to 2 oil and 148 water. After DAPS was installed, the oil rose to 12 barrels per day and the water dropped to 90. The polish rod stroke remained at a 54" length and 8 spm. The stroke length was increased to 74" to increase the withdrawal rate from the well. This increased the oil to 16 bopd and the water to 114 bpd. In the five months since increasing the stroke length, Chevron's well has averaged 16 barrels of oil and 140 barrels of water per day. The total cost of this project, which included an acid job on the injection formation, was paid out in less than 64 days. Like Texaco, Chevron is currently reviewing well files to determine the next candidates for the Dual Action Pump in East Texas.

Testing DAPS in Canada

Background and Motivation to Test DAPS. Talisman

Energy Inc. has approximately 700 vertical and horizontal producing oil wells in their Southeast Saskatchewan operating area of Canada (600 miles East of Calgary, Alberta). Aggressive drilling brings on 50-100 new wells per year. Initial production is often clean oil. The nature of the bottom water drive of the Williston Basin wells, however, is for water cut to increase quickly to about 80%. Then water cut increases gradually to 95% over a number of years.

Typically, the large amounts of new water produced are handled by executing expansions at the processing batteries. Free water knock-out vessels, water disposal pumps, pipelines, and disposal wells are added. This activity is capital intensive and leads to high operating costs for treating and disposal of water volumes. Also, production from exploration and other remote wells is typically trucked at high cost from single well batteries to distant processing batteries until local facilities can be justified.

The costs associated with the activities described above created a strong driver for finding new methods of reducing water production. Talisman was immediately interested upon learning of DAPS from Texaco and Dresser. At the time, field tests conducted by Texaco in the USA matched fairly well with the oil API and gas content seen in Talisman's Parkman field. It is a high watercut pool with 34.4° API oil and solution GOR of 129 scf/bbl. Parkman vertical wells typically produce 300 - 1200 bpd total fluid. It was clear that the system would have to be expanded to higher fluid rates to be of strong interest.

The decision was made to design and test a DAPS system with capability just over 1000 bpd total fluid. The geology of the field required that the disposal zone be located in a formation only 40 feet below the producing zone. It was separated by a chalk seal layer. Both production and disposal zones are fractured Mississipian age carbonate sequences. Porosity and permeability are 12% and 13 mDarcy respectively. Refer to **Figure 2** for a wellbore schematic drawing. As shown, the producing depth is 3420 feet. To install the system, Talisman had to drill out the plug back cement. The producing formation was held back by a $CaCO_3$ pill. The disposal formation was then perforated through casing. A casing packer was installed to isolate the injection formation. To test the DAPS system at 1000 bpd total fluid, the drawdown on the well had to be increased. The DAPS system was designed for higher withdrawals than the original rate of production on the well. Previously, it had been producing with a high fluid level.

Results. The system was installed in July 1996. After dealing with startup problems, stable operation was achieved. The production values before and after the system installation are shown in **Table 1**.

As shown, the total well inflow was increased to 1068 bfpd and successful separation was achieved. The quality of separation was verified with the use of a bubble tube. This is a capillary string of 1/4" tubing running from the injection zone to surface. This allowed monitoring of injection pressures and the lifting of disposal water samples to surface. It was known prior to installation that the injection zone back pressure may not be high enough to force sample fluid flow to surface. Upon installation, it was found that the pressure was just enough to obtain samples. However, this was only when the fluctuating injection pressure was at maximum and when there was no particulate buildup in the tube. As such, proper purging of the bubble tube and extended sampling of the disposal water was not possible. However, a few samples were obtained and were shown to have less than 100 ppm of oil in water. This is comparable to the separation efficiency of free water knock-out vessels in this field.

Problems. The main problem encountered on this project was the production of $CaC0_3$ and limestone formation fines after DAPS installation. Original production from this well contained no particulates, as the well had been at stable rates for many years. Preparatory work included introduction of a $CaCO_3$ pill to the producing formation during completion operations and acidization to remove it. Along with increased drawdown on the well, these caused the onset of fines migration and particulate production.

On initial startup, the well never achieved stable production. This was due to rapid buildup of fines, plugging off all valves and the production zone. The system was pulled within days for a thorough acid cleanup of both the production and injection zones. Upon reinstallation, the system started up without problem to yield the results shown earlier. Unfortunately, fines production continues to be a problem on this well, with several acid jobs having been required at two month intervals to date.

The system has been demonstrated to work effectively up to 1068 bpd total fluid. However, the fluid must be free of significant particulates to run for long periods without disposal zone plugging.

Potential Applications of DAPS

Although DAPS is a relatively low cost technology itself, the cost of preparing some wellbores for simultaneous production and injection can be expensive. Economic justification will usually be more dependent on well work costs than on pump costs.

Revenue Generation. Increased production is possible in several ways. Artificial lift constraints are a problem that can sometimes be overcome by DAPS. Applications tested to this point indicate that a pumping unit can sometimes move 30% more fluid with DAPS than it can for a similar conventional application. Another approach is to convert conventional injection wells to DAPS. Injection can be maintained in the deeper zone while moving uphole to a high water cut zone that can not only provide enough water to maintain desired injection but also produce oil. Uneconomic wells may be returned to production in some cases.

DAPS could make it practical to develop waterfloods in small reservoirs underlying a mature flood. Additionally, it may be possible to improve vertical and even horizontal sweep efficiency in multilayer reservoirs by use of DAPS. A demonstration project was proposed to the DOE, but its rejection has delayed proof of this concept.

Expense Reduction. DAPS was originally conceived as a means of reducing water handling costs. However, it is often difficult to justify conversion to DAPS if water is being handled at a cost of around ten cents a barrel or less. Five hundred barrels of water a day at ten cents a barrel is only fifty dollars a day. There are numerous leases where water is being handled at over $.30 a barrel, though. These cases can make expense reduction as significant as revenue generation. Trucking and disposal fees are often two sources of this cost.

Trucking savings were the foremost benefit realized by Talisman. Remote wells often truck production out from single well batteries. These quickly go uneconomic when water production increases. Trucking costs range from $US 0.35/bbl of fluid up to $US 1.50/bbl for distant routes. As such, a DAPS system can often be justified with as short as a two month payout.

Third party processing and water disposal fees were also significant to Talisman. These fees range from $US 0.30/bbl to $US 0.70/bbl of fluid processed when handled by a third party facility. DAPS can be justified with payouts as short as 4 months in these cases, if wellbore and geological conditions are favourable.

Another unique feature demonstrated by DAPS testing is that water production diagnostics (e.g., cased hole logs) are far less important than with chemical water shutoff treatments. The source of the water does not impact the operation of DAPS. DAPS will handle uniform influx of water equally as well as from a thin water stringer. In other words, it is not imperative with DAPS to identify which perforations are producing most of the water. Conversely, water shut off techniques usually require that most of the water is coming from a specific interval that can be plugged.

In spite of the fact that more fluid was being moved, the unit speed was actually reduced in several installations. The ramification of this is that well failure rates could be reduced.

Both Texaco and Talisman found that operating costs are often low enough that it is not possible to justify installation of DAPS for electrical savings alone. Other benefits as detailed above must accompany those savings.

Investment Savings. Wells that are candidates for larger lift equipment, such as submersible pumps, may be candidates for DAPS. The cost of converting to an ESP could justify the investment needed to install DAPS. DAPS will have a much lower operating cost than an ESP.

Another potential investment benefit is the use of DAPS to avoid the cost of installing additional water handling facilities. Overloaded disposal wells or facilities may require investing capital. DAPS might provide the reduction in water volumes needed to continue without further investment. Similarly, the cost of complying with regulations that require pit closures may be reduced by use of DAPS and smaller facilities.

When drilling a number of new wells in an older established field, water handling and disposal facilities in Canada can require expansion ranging from $US 200,000 to $US 750,000. Such expansion usually is accompanied by increased operating costs at the facility. With the availability of DAPS, it is now worthwhile to first analyze the nature of field production and geology. Consideration should be given to the conversion of older, high rate and high watercut wells to DAPS rather than battery expansion. If conditions are right, this could often be done for less overall capital, while reducing water volumes and operating costs. This can be particularly true for small, isolated leases.

DAPS may be an excellent alternative for waterflooding small reservoirs or conducting pilot floods. Typically, this requires investing in injection pumps, filtration, and injection lines. As an alternative, an operator might be able to provide injection water from a shallower, high water cut interval with DAPS. A "projector" is both a producer and an injector. Projectors could generate revenues from shallower intervals (at a lower lifting cost). They could make a waterflood justifiable at almost no additional expense and a nominal investment.

Environmental Benefits. The benefits of producing less water seem readily apparent. They are worth enumerating, though, because these benefits can become part of the economic justification of DAPS. Trucking and water treating are the more obvious impacts of brine production. Demulsifiers, oxygen scavengers, corrosion inhibitors, and scale inhibitors are just a few of the chemicals that may be necessary when handling water. Sand and diatomaceous earth filters generate solid wastes. As much as eighty per cent or more of the produced water can be injected rather than handled at the surface. (This is a function of well parameters and the pump design.) DAPS reduces the amount of water treating and handling that is necessary. This reduces the need to use and handle chemicals, and thereby reduces the potential for environmental complications.

The use of less energy to handle brine can have both direct and indirect benefits. Fired heaters, used to separate produced water from hydrocarbons, are often a target of environmental monitoring. Use of less heat to provide separation can help alleviate the emissions and potential impacts on flora and fauna. Benefits of reducing energy demand would be realized at power generation facilities.

Brine contamination is becoming an increasingly difficult issue for the oil industry. Reducing the quantity of brine handled at the surface can help alleviate load on facilities. Line leak frequency can be reduced by handling less pressure and rate in surface lines. This, in turn, can reduce the cost of surface damages.

Handling less water at the surface can reduce the footprint of oil operations. Retention time in vessels can be increased. DAPS could lessen the need to use pits. The use of fewer and smaller tanks and vessels could reduce damages to the surface. Trucking brine to a disposal site can be a problem in environmentally sensitive areas.

Application Criteria

While there are numerous applications for DAPS, there are also limitations. The following criteria can be used for initial candidate screening and selection.

Multiple intervals. The most important requirement is the existence of a suitable injection or disposal interval. **Figure 3** provides a conceptual drawing of a typical installation. The injection interval must be deeper than the production perforations by a minimum of about ten feet. Isolation between the two intervals is necessary. The injection zone can be the same formation as the producing zone provided that the perforated intervals are not communicating actively. The pressure required to inject water should not be excessive. The injection pressure gradient of the candidates tested has been low or moderate (less than 0.45 psi per foot of depth). Modeling work, as well as experience from some of our testing, indicates that higher injection gradients can be achieved. The produced water must be compatible with the injection zone. It is usually inadvisable to mix water from carbonate and sandstone reservoirs. However, bacteria and scaling problems caused by oxygen introduced at the surface or by temperature changes should not be as much of a problem. This is attributed to that fact that DAPS does not bring as much water to surface.

Zonal isolation. A common constraint is casing integrity. As with any injection well, the casing (and the cement behind it) must be suitable to set a packer and withstand injection pressure. This is often a "fatal factor" for older wells that have experienced casing leaks and extensive corrosion. It is best to have impermeable strata between the injection and producing zones.

Fluid separation. Another important factor is oil-water separation. The wellbore must be relatively vertical between the location of the upper and lower valves for separation to occur. Although it has been shown from downhole videos that oil rises to the top of the fluid column, it is anticipated that this will not be true in certain situations. Cold, heavy crudes which are approaching 10° API or less may not be good candidates. Wells that produce tight emulsions are not necessarily poor candidates. The emulsion may be a result of mixing in the pump chamber.

Operation and Features

The Dual Action Pumping System is a radical departure from conventional rod pumping, but it consists primarily of off-the-shelf components. Essentially, DAPS consists of 1) an upper pump, 2) a lower pump, 3) valves for injecting water into the disposal zone, and 4) a packer to isolate the production and disposal zone. The upper pump can be either a tubing type or insert type API rod pump. It does not have a standing valve but has the addition of an extra top plunger cage to connect the plunger to the valve rod of the lower pump. The lower pump consists of a tubing pump less both the standing and the traveling valves. The traveling valve has been replaced with a solid valve seat. This prevents communication through the plunger enabling both injection and lift. A stationary valve located between the two pumps acts as the standing valve for the differential displacement of the two pumps to the surface. The lower valves consist of an intake valve and an injection valve. Both valves are made from standard rod pump valve components with the addition of fittings that channel fluid in from the annulus and below the packer through the tubing. The injection valve is a simply a check valve with tubing threads that prevents back flow of water from the injection zone during the lifting cycle. Sinker bars or weight bars are normally placed above the top pump to provide the force necessary to overcome the injection pressure opposing the downward movement of the bottom pump.

Physical Description. A distinguishing feature of DAPS is that it has two sets of intake ports and two plungers (**Fig. 4**). The upper ports, contained on the outside of the pump housing, are the point of entry for all produced oil and some produced water for the upper plunger. The lower ports are contained in a valve assembly and feed the bottom plunger. This valve assembly is the intake point for all water standing in the annulus beneath the producing perforations.

The top half of DAPS consists of a conventional pump with a plugged plunger oriented downward to inject water. Fluid enters the pump on the upstroke and the traveling valve closes on the downstroke.

A lower valve assembly is placed on the tubing string between the lower pump and the injection packer. Water standing in the annulus above the injection packer enters into the lower pump chamber through the lower valve assembly

Functional Description. The operation of DAPS can be broken into two cycles: the injection cycle and the production or lifting cycle. Since the cycles operate concurrently, they each have an impact on loading of the other cycle.

Injection Cycle. The relatively simple injection cycle is shown in Figure 4. On the upstroke, water enters the tubing below the pump through the lower valve assembly. On the downstroke, injection pressure is primarily provided by the fluid column in the tubing and the weight of sinker bars placed immediately above the top pump. Other parameters, depending on well conditions, can also assist in providing injection pressure. The location of the lower valve assembly usually is not critical. It can be situated anywhere below the pump provided that it is placed lower than the producing perforations but above the injection packer. This can range from just a few feet to thousands of feet deeper than the pump itself.

Lifting Cycle. The lifting cycle is more complex. **Figure 4** shows that, on the downstroke, the top valve (normally the "traveling valve" of a conventional pump) closes to carry the weight of the fluid in the tubing. The external valve opens to allow fluid to enter the pump chamber. On the upstroke, the external valve closes off the annulus and the top valve opens. Oil and water are physically being lifted by the lower plunger. They are passed from the larger pump chamber of the lower pump into and through the upper pump chamber. The relationship in size between the two plungers, which are joined by a connecting rod, determines the proportions of fluid lifted and injected.

Environmental Permitting

A new challenge created by DAPS is the matter of underground injection control. Many agencies require operators to annually report rates and pressures. Monitoring and reporting injection pressures and rates is more difficult with this configuration than with a conventional injection well. Direct measurement of injection pressure in a conventional injection or disposal well is a relatively simple matter. With a pump, valve assembly and rods in the tubing, it is not as easy to measure injection rates and pressures below the injection packer with DAPS.

It can be demonstrated that injection rates and pressures can be calculated with reasonable certainty from surface conditions. Injection rates can be calculated from pump displacement, speed and stroke length. Testing at the Rocky Mountain Oilfield Testing Center (RMOTC) demonstrated that maximum injection pressure can be determined from the minimum polish rod load. It is intended that the analysis of quantitative data received from the RMOTC test will be reported to industry in the future. Talisman and Texaco have each met with the respective governing agencies prior to installing DAPS in various states and provinces to discuss the experimental nature of the tests being conducted.

DAPS provides an additional measure of protection for shallow aquifers. In the event that communication starts occurring behind the wellbore, the zone producing water for injection purposes also provides a pressure sink for water trying to migrate out of zone. This would be detected with changes in water cut at the surface.

Canada - Injection Zone Monitoring.

Injection zone monitoring is a subject which requires careful planning. It is always useful to have monitoring systems for troubleshooting. Unfortunately, the unreliable nature of downhole electronic pressure and flow monitoring systems often limits the feasibility of their use. In addition, the high cost of such systems can often cause the project economics to fall below the minimum acceptable hurdle rate.

A bubble tube was used to measure injection zone pressure on the Parkman installation by tying into the disposal water tubing just above the packer. (**Figure 2.**) The system has the advantages of being mechanically more robust than electronic cable. It is also lower in cost and can sample injected water quality. To measure injection pressure, nitrogen is injected at surface from a portable bottle. When the disposal water has been fully displaced to the bottom of the tube, the gage measuring the nitrogen pressure will stop rising. This indicates all water head has been displaced. The flowrate of nitrogen is then cut back to a trickle to eliminate friction effects. The injection zone pressure is then the sum of the surface pressure and the calculated nitrogen head in the bubble tube (usually minimal).

To obtain disposal water samples, the tube is simply blown down to atmosphere. There must be enough disposal zone pressure to overcome the water head required to produce water to surface through the bubble tube. If water flow is achieved, simply purge a full bubble tube volume of water then take a representative disposal water sample. For systems where injection pressure is insufficient to have bubble tube flow reach surface, dual bubble tubes with a simple form of gas lift are being investigated.

If confidence exists regarding separation efficiency and injection pressure expectations, injection zone monitoring costs may not be necessary. Further knowledge is derived from baseline and subsequent dynalog surveys. These give an indirect indication of disposal pressure. If such confidence does not exist, a bubble tube can be used for the first DAPS application until field specific information is gained in disposal zone performance and separation efficiency.

Canadian authorities have generally embraced the DAPS system. It should benefit producers as well as the government by extending economic limits, hence leading to larger ultimate reserves. As such, they have placed fairly minimal requirements on the regulatory approvals process. Depending on the jurisdiction, a letter-type summary of the project intentions and method of disposal zone monitoring (if any) is required when water disposal is deemed to be within the same zone as production. For water disposal to a separate zone, a process similar to the existing one for water disposal wells is required.

The regulatory bodies have generally requested brief progress reports bi-annually so they can learn along with the producers. These reports include calculated approximations of the volume of water injected to the disposal zone.

Modeling DAPS

An all-inclusive design program for this system is not available. Currently available commercial design software utilize a numerical solution of the damped wave equation, calculation of rod buckling tendency, and a constant downstroke pump load (e.g., NABLA's SROD$$). These, coupled with a spreadsheet, are sufficient to design a system. Other software packages are being utilized. The software package must include a means to enter a downhole load acting at the pump on the downstroke. This is needed to model the injection forces acting up on the lower plunger. The process using these tools is iterative but fairly straightforward.

The upstroke surface loading (e.g., unit torque, structure loading, rod loads, etc.) is determined in a conventional manner using the lower plunger size. The lower plunger provides the work to produce and inject. The upper plunger only provides a moving seal. Although the loads are dictated by the lower pump, the surface rate is based on the difference in two pump areas. The pump intake pressure must reflect the total flow rate from the perforations (both production and injection). The injection rate is calculated directly from the lower plunger size.

On the downstroke, sufficient force from the fluid load in the tubing and annulus and buoyant weight of the rod string is needed to overcome the injection forces without buckling the rod string. The traveling valve is closed and the side intake valve between the pumps is open on the downstroke. Therefore, a portion of the hydrostatic load in the tubing and annulus acts on the lower plunger. The force required to inject water downhole is counteracting these forces underneath the plunger. This upward force imposed on the lower plunger is modeled by calculating a force balance of these loads at the lower plunger. The load is entered into SROD$$ as a pump friction only acting on the downstroke. Within the program, this load acts as an upward constant force on the downstroke of the cycle. This enables the model to more accurately predict sucker rod buckling during the injection cycle.

Expanding the Envelope.

Currently there are relatively few wells with DAPS installations. The focus has been to determine where DAPS can be used. Follow-ups to the original tests are now (in the first half of 1997) being designed.

Tool Limitations. The widest application for DAPS systems in Canada is for vertical wells with 5.5" casing. It is common to see total fluid rates over 1500 bpd. Due to physical size constraints, the largest system available in 5.5" casing is 2" x 2.25." For typical pumpjack stroke and speeds, this limits withdrawals to about 1000 bpd. If a lower-profile, side intake mandrel (ie the upper port) can be developed, separation efficiency can be tested at higher rates by using larger pumps – potentially up to 2.75" or 3.25" in size.

An injection valve assembly has been designed for 4 1/2" casing applications. This has not been tested at this time. Resolution of this limitation will open the door for numerous follow-ups to the East Texas well tests.

Deep Wells. Talisman Energy has just begun testing DAPS in a deep well approximately 400 miles Northwest of Calgary, Alberta. The production zone is a carbonate formation at a depth of 8400 ft. The disposal zone is at 8550 ft. The specific gravity of the water is 1.1, and the oil is 36° API. Initial results demonstrate successful separation and operation as shown in **Table 1**. Note that this well has only been running since April 1997. At the time of writing this paper, the system is in the process of being sped up to optimized rates. The expected "optimized" results are also shown in **Table 1**.

Heavy Oil. Talisman Energy is currently testing a DAPS system approximately 250 miles northeast of Calgary, Alberta. One goal is to extend the service envelope to include heavy oil fields. The producing zone is the Dina sand at a depth of 2300 ft. The disposal zone is at 2360 ft, and is separated from the producing zone by a seal layer of rock. Production is from a consolidated sandstone, but produced fluids are free of particulates. The produced water specific gravity is 1.05 with 17.5° API oil.

The system has only been running since April 1997, and was started up at low rates as a precaution. The preliminary results demonstrate successful separation and operation. This is evidenced by an excellent match with the well inflow performance curve. The pumpjack is currently being sped up to approach an optimal pumped off condition. The "future optimized" data is shown in **Table 1.** Based on successful results to date, it represents the expected condition when a pumped off condition is realized.

Monitoring. A baseline dynomometer survey a few days after startup is usually useful for comparison to surveys done later, especially if problems are encountered. It can be used for the usual diagnostics, as well as giving an indication of whether the disposal zone pressure is increasing over time. Testing at RMOTC and other wells discussed above is providing excellent quantitative data that will be used for this purpose. This testing may provide a means to quantify injection pressure beneath the packer. It may also yield a means to identify equipment failures when they occur. Pump failures can be detected by use of production data and dynomometer data. This information will be discussed in a future paper.

Optimizing fluid levels in DAPS wells is a challenge that will be evaluated. DAPS will not develop a fluid pound in the same manner as a conventional well. If the upper pump is "starved," all produced liquids will be injected by the lower plunger. When the working fluid level falls below the upper intake, the lifting cycle is "starved," while the lower valve assembly will continue feeding the injection cycle. Consequently, the produced oil would be injected along with all the water if this occurs. Accordingly, DAPS should not be used to completely pump off a well.

Other Challenges. Still other problems must be resolved. Wells with poor injectivity need to be tested to determine whether DAPS can economically overcome high injection gradients. Even the issue of accounting for a well that is both producing and injecting presents a challenge that may test a company's accounting system.

Both the design and the permitting process must be streamlined. Nabla Corporation is working with Texaco to improve modeling predictions. Agencies in the several states and provinces where tests have been performed have indicated willingness to learn more about the potential of DAPS.

Not every installation of DAPS to the time this paper was submitted is reported. While most systems have actually exceeded our expectations, a few have not been as successful as those described. Two wells, identified as DAPS candidates, experienced casing failures during wellwork prior to installing DAPS. Another experienced casing failure about a week after the wellwork. Oil production increased only slightly in another (but the surface water was reduced dramatically). Some installation problems arose in others, but Dresser personnel have gained valuable experience to prevent a similar recurrence.

Future Developments.

It has been shown that the DAPS system can be applied to improve the economics of mature fields. It can reduce the capital expenditure associated with water handling for newly drilled locations. Any reservoir engineer will say that the extension of the economic limit for a well or field results directly in incremental reserves being recovered. This benefits industry, royalty owners, and governments alike. The challenge now is to continue to extend this technology to applications with higher rates, lift from greater depth, and lower API gravity oil. As demonstrated, projects are currently underway to achieve this.

The commitment of the authors' companies to better manage water production has led to the conclusion that a whole new class of artificial lift lies in the future. Industry has a term for this class of new technologies: Dual Injection and Lifting Systems (DIALS). The Centre for Engineering Research (CFER)[3] has developed a line of products such as their "Aqwanot" that utilize hydrocyclones to separate water and oil downhole. DAPS utilizes gravity segregation to selectively lift oil and some water to surface while injecting the remaining water. Encouraged by the success of DAPS, Texaco has other DIALS technologies in various stages of development. Each of these systems utilize the same, key principle that led to the invention of DAPS -- downhole gravity segregation of water and oil.

Each installation of the DAPS technology has opened our eyes to exciting, new potential. For example, anything less than a 20° API crude was considered an unlikely candidate a year ago. Talisman's test, as well as other evidence, gives reason to believe that DAPS could work in some fields with 13° API crudes. The RMOTC test has demonstrated the feasibility of waterflooding a water-sensitive zone with water from a shallower oil reservoir.

Conclusions.

The degree of successful application of DAPS systems to achieve the benefits detailed in this paper rests solely on the technical and communication skills of the teams involved in the exploitation and production of oilfields. No longer can the attitude of "we'll find the oil, then Operations can worry about producing it" exist. Geologists need to interact with exploitation and production engineers. They need to consider factors like remote distances to well locations, trucking costs, drilling to disposal depth, and battery capacity when planning drilling locations. Does it make sense to consider DAPS? Does a suitable disposal zone exist? At least one location has been drilled by Talisman Energy to date which would not have been previously deemed a viable exploration target due to high water cut and remote trucking costs. The plan incorporated a DAPS system from inception, which rendered the target economic.

Acknowledgments.

The authors appreciate the support of their respective companies to allow preparation and presentation of this paper. We thank Halliburton Energy Services for providing slides for the presentation. Chevron and RMOTC have our gratitude for allowing inclusion of information regarding tests in their wells. We credit Texaco's Dr. Howard McKinzie who immediately grasped the potential of DAPS and committed the resources to develop it. Texaco's Mr. Ronnie Threadgill is commended for taking the risk to test the first and second prototypes as well as help solve the problems that arose. We gratefully acknowledge Dr. Sam Gibbs and Ken Nolen of Nabla Corp for their valuable assistance and advice in designing a modeling process and for reviewing this paper.

References.

1. "Introducing a Concurrent Process of Gas Production and Water

Disposal", MBC Inc. brochure 1994.
2. Halliburton Down Hole Video Services, Halliburton Energy Services video, 1994.
3. Mathews, C., Chachula, R., Peachey, B., Solanki, S., "Application of Downhole Oil/Water Separation Systems in the Alliance Field" paper SPE 35817 presented at the Third International Conference on Health, Safety & Environment in Oil & Gas Exploration & Production, New Orleans, LA, June 9-12, 1996.

Table 1 - DAPS Production Comparisons

	Test	Surface Oil Prod, bopd	Surface Water Prod, bwpd	Water to Disposal, bwpd	Fluid Level, ft From Surface
Before DAPS	E. Texas	3	184	0	834
After DAPS		10	126	392	1131
Before DAPS	Parkman	14.5	221	0	312
After DAPS		35	151	882	561
Before DAPS	Deep test	27	932	0	3085
After DAPS		28	179	851	2900
Optimized		33	209	993	4080
Before DAPS	Heavy Oil	25	250	0	1400
After DAPS		32	25	265	1495
Optimized		38	38	400	1900

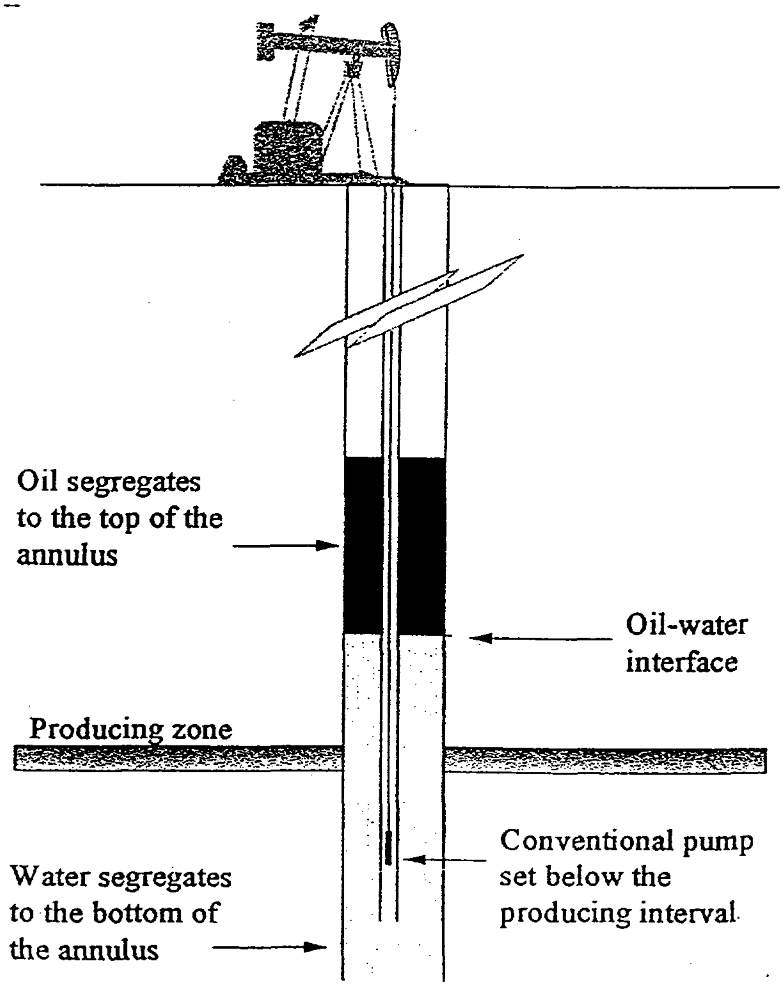


Fig. 1–The well in this example has a conventional pump set beneath the producing perforations. If it stops producing for several days and then is put on production, it will produce only water for hours or days – demonstrating gravity segregation.

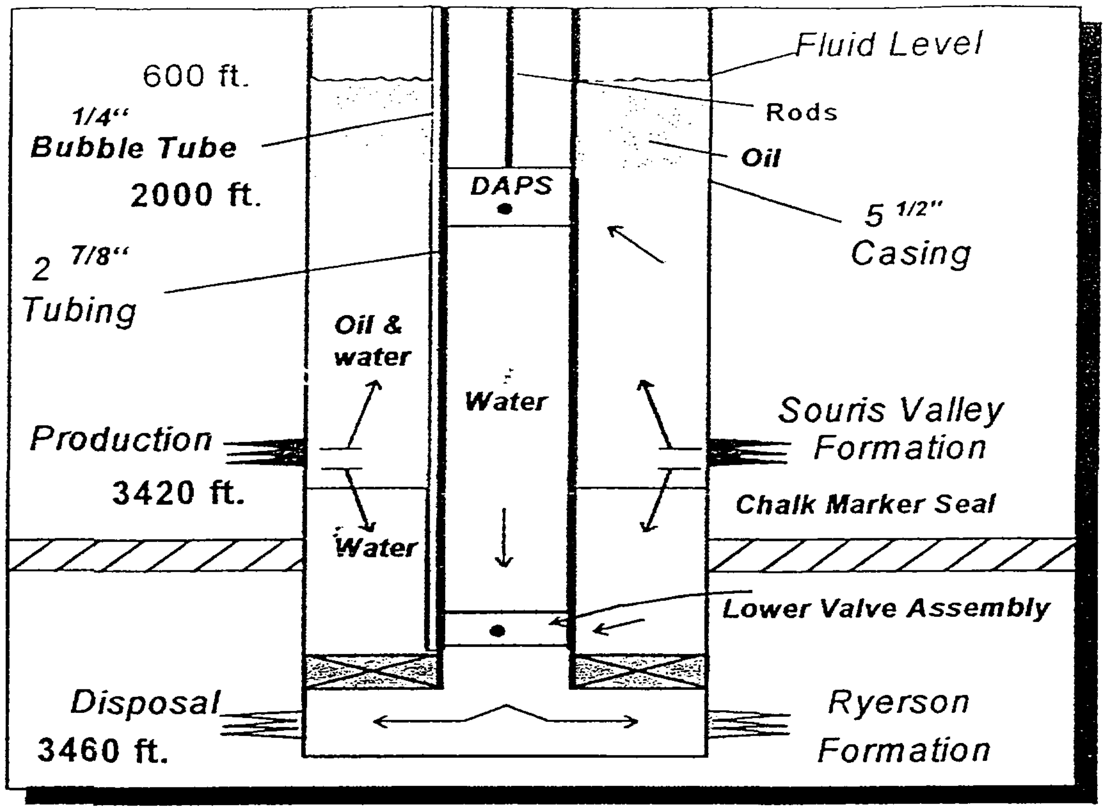


Fig. 2–Talisman Energy Installed DAPS in the Parkman Field in Canada – more than doubling production. Both the injection and the lifting pumps are placed much shallower than the injection valve assembly.

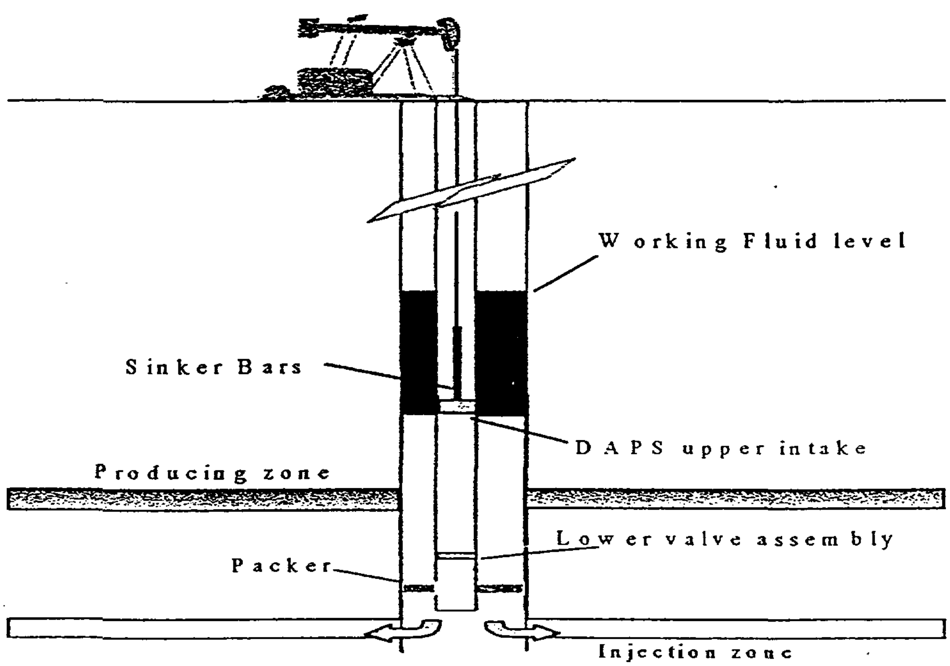


Fig. 3–DAPS requires an injection zone to function. Two separate reservoirs are shown, but one continuous reservoir with 10' between producing and injection perforations could work.

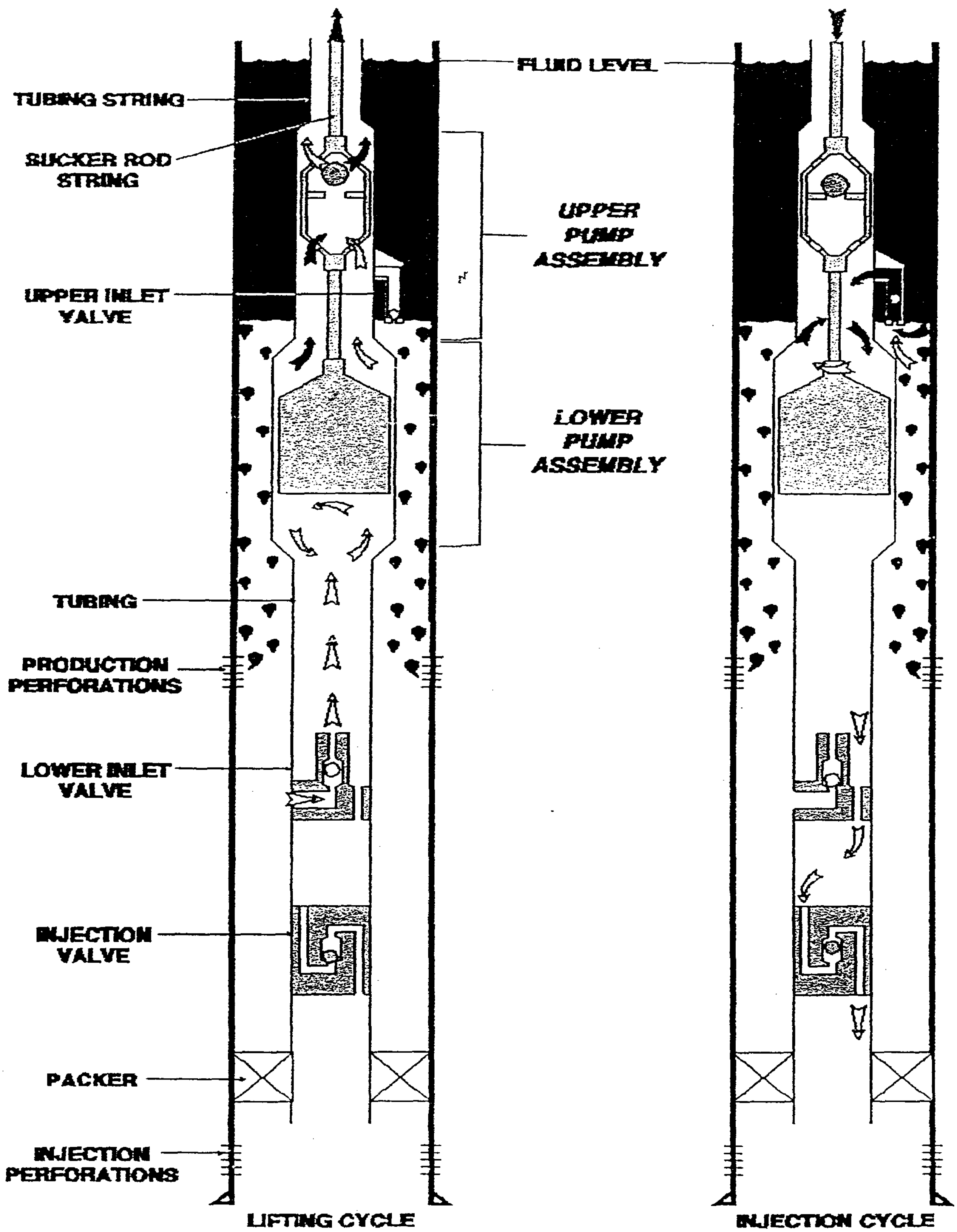


Figure 4. Schematics of the lifting and injection cycles of DAPS (Patent # 5,497,832) show how it selectively lifts oil and some water but injects only water. The two valves comprising the Lower Valve Assembly (patent pending) are shown separately as the "Lower Valve Inlet" and the "Injection Valve." There can be significant vertical separation between the pumps and the Lower Valve Assembly.

VIII. Geological Data

GEO. UNIT: 110AVMB

WATER LEVELS IN FEET BELOW LAND SURFACE DATUM

DATE	WATER LEVEL MS
JAN 17, 1991	76.72 S

SITE ID: 323039103432501
LOC: 21S.32E.06.11131
OTID 10555
ELEV: 3597.00
USE: S
DEPTH: 55
GEO. UNIT: 110AVMB

WATER LEVELS IN FEET BELOW LAND SURFACE DATUM

DATE	WATER LEVEL MS	DATE	WATER LEVEL MS	DATE	WATER LEVEL MS	DATE	WATER LEVEL MS
DEC 01, 1965	42.50	FEB 03, 1971	44.04 R	MAR 10, 1981	46.21		
MAY 29, 1968	45.34 P	FEB 25, 1976	43.66	MAR 21, 1986	48.64		

HIGHEST 42.50 DEC 01, 1965
LOWEST 48.64 MAR 21, 1986

IDATE: 03/04/97 PROVISIONAL GROUNDWATER DATA LEA COUNTY, NM. PAGE 996

SITE ID: 323039103432502
LOC: 21S.32E.06.11131A
OTID 10556
ELEV: 3597.00
USE: H
DEPTH: 55
GEO. UNIT: 110AVMB

This well is as close to the area you needed a water level as we have.

WATER LEVELS IN FEET BELOW LAND SURFACE DATUM

DATE	WATER LEVEL MS	DATE	WATER LEVEL MS	DATE	WATER LEVEL MS	DATE	WATER LEVEL MS
FEB 03, 1971	43.50 R	MAR 10, 1981	45.87	APR 18, 1991	51.69		
FEB 25, 1976	43.18	MAR 21, 1986	47.18				

HIGHEST 43.18 FEB 25, 1976
LOWEST 51.69 APR 18, 1991

SITE ID: 323029103321501
LOC: 21S.33E.02.24141
OTID 10557
ELEV: 3792.00
USE: U
DEPTH: 120
GEO. UNIT: 110AVMB

* There are no wells within ½ mile of the location you gave us.

WATER LEVELS IN FEET BELOW LAND SURFACE DATUM

WATER WATER WATER

X. Well Logs

COMPANY: **Texaco E & P Inc.**

WELL: **Bilbrey "30" Federal No. 5**

FIELD: **Lost Tank Delaware**

COUNTY: **Lea** STATE: **New Mexico**

COUNTY: Lea
Field: Lost Tank Delaware
Location: 1980' FSL & 1980' FEL
Well: Bilbrey "30" Federal No. 5
Company: Texaco E & P Inc.

Schlumberger

Platform Express
Compensated Neutron
Lithi-Density / GR

LOCATION

1980' FSL & 1980' FEL

Elev.:	K.B.	3691.8 F	
	G.L.	3680 F	
	D.F.	3690.8 F	
Permanent Datum:	GROUND LEVEL	Elev.:	3680 F
Log Measured From:	KELLY BUSHING	11.8 F	above Perm. Datum
Drilling Measured From:	KELLY BUSHING		

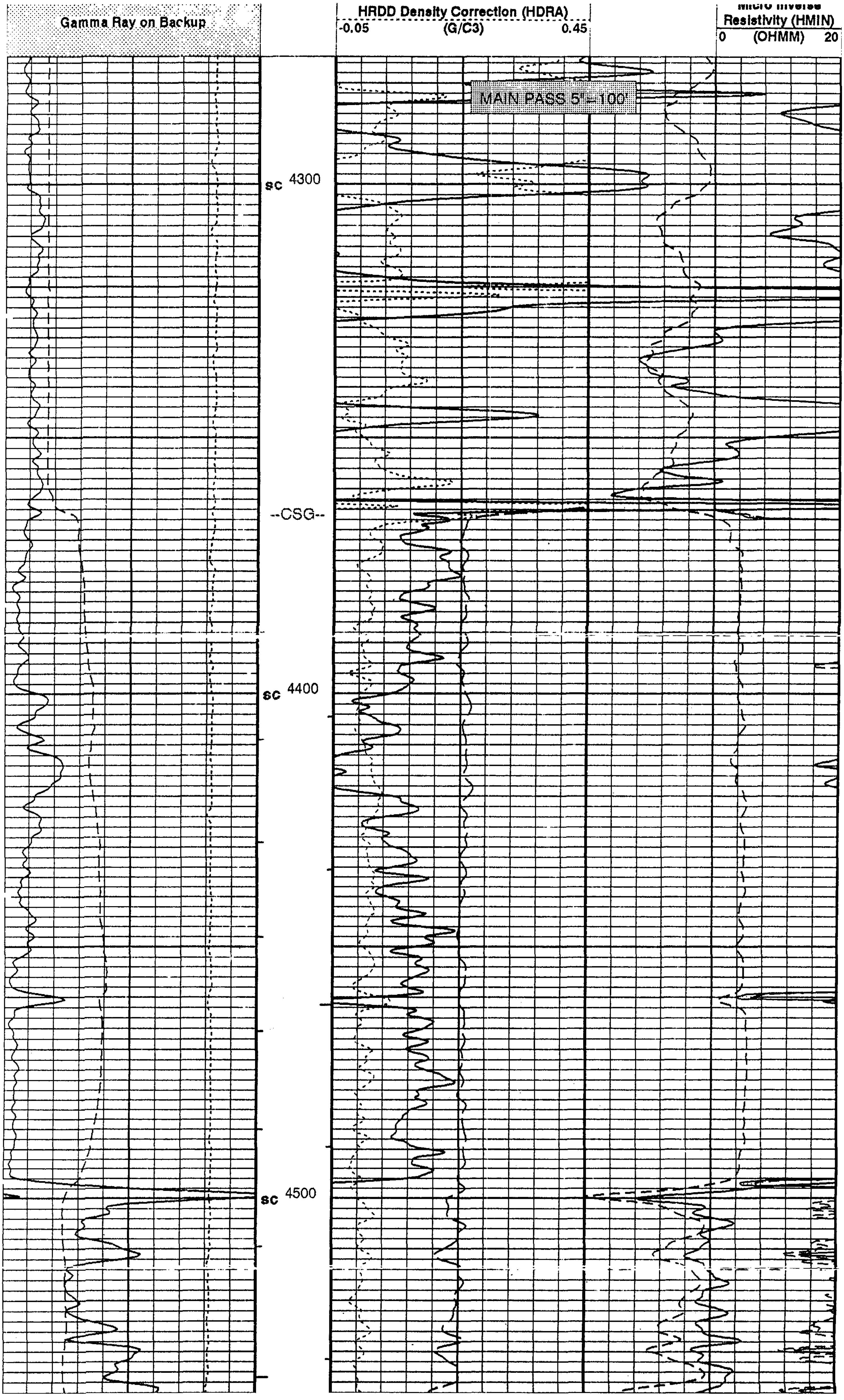
API Serial No.	SECTION	TOWNSHIP	RANGE
30-025-33647	30	21S	32E

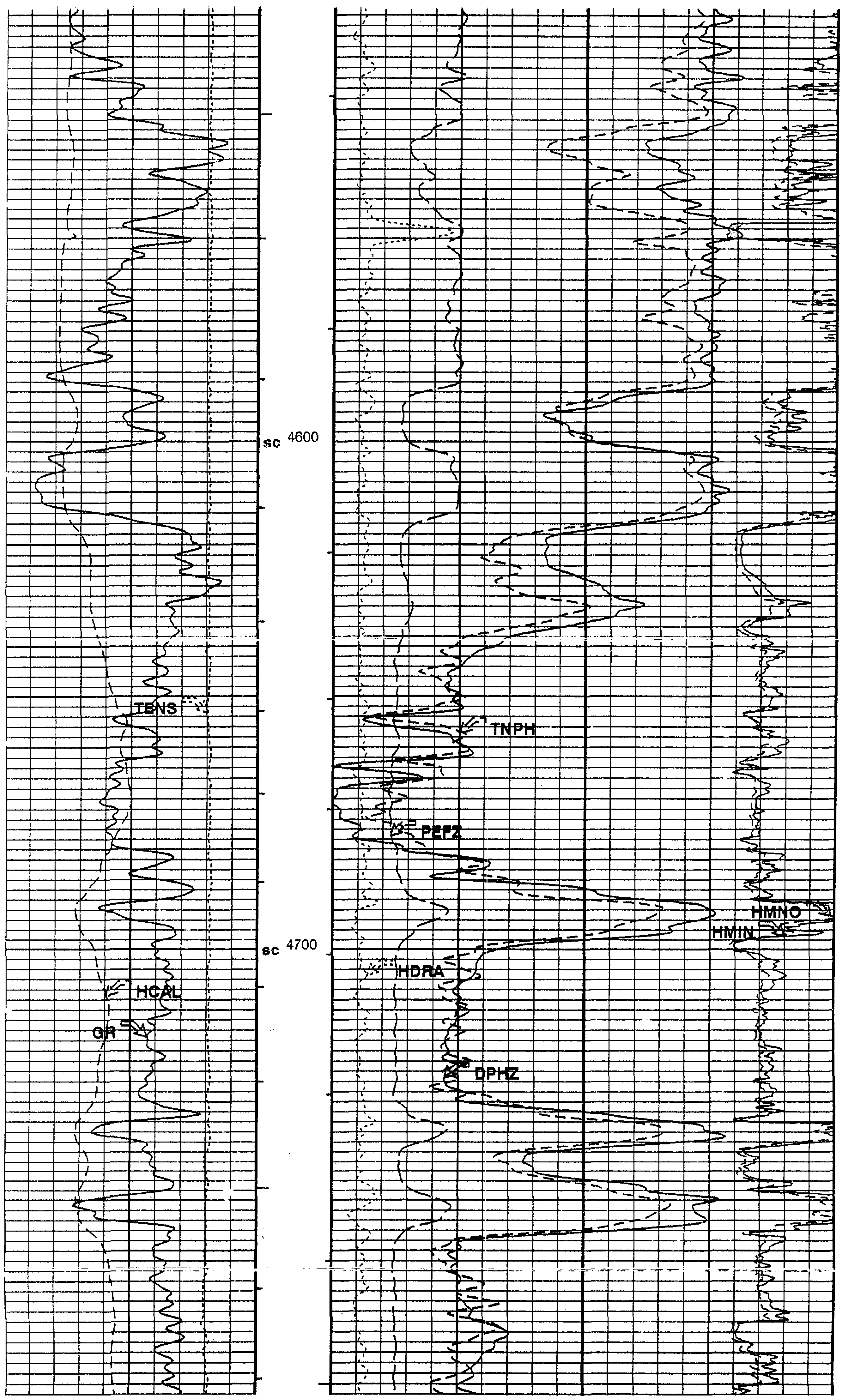
Logging Date	18-DEC-1996			
Run Number	ONE			
Depth Driller	8916 F			
Schlumberger Depth	8902 F			
Bottom Log Interval	8885 F			
Top Log Interval	200 F			
Casing Driller Size @ Depth	8.625 IN	@ 4380 F	@	
Casing Schlumberger	4364 F			
Bit Size	7.875 IN			
Type Fluid In Hole	FRESH MUD			
Density / Viscosity	8.7 LB/G	29 S		
Fluid Loss / PH	8 C3	9		
Source Of Sample	CIRCULATION TANK			
RM @ Measured Temperature	1.270 OHMM	@ 49 DEGF	@	
RMF @ Measured Temperature	1.270 OHMM	@ 49 DEGF	@	
RMC @ Measured Temperature		@	@	
Source RMF / RMC	MEASURED			
RM @ MRT / RMF @ MRT	0.568 @ 118	0.568 @ 118	@	@
Maximum Recorded Temperatures	118 DEGF			
Circulation Stopped / Time	18-DEC-1996	4:15		
Logger On Bottom / Time	18-DEC-1996	13:30		
Unit Number / Location	3031	HOBBS, NM		
Recorded By	B. H. BOEHME			
Witnessed By	TOBY BLACK			

	Run 1	Run 2	Run 3	Run 4
Logging Date				
Run Number				
Depth Driller				
Schlumberger Depth				
Bottom Log Interval				
Top Log Interval				
Casing Driller Size @ Depth		@		@
Casing Schlumberger				
Bit Size				
Type Fluid In Hole				
Density / Viscosity				
Fluid Loss / PH				
Source Of Sample				
RM @ Measured Temperature		@		@
RMF @ Measured Temperature		@		@
RMC @ Measured Temperature		@		@
Source RMF / RMC				
RM @ MRT / RMF @ MRT	@	@	@	@
Maximum Recorded Temperatures				
Circulation Stopped / Time				
Logger On Bottom / Time				
Unit Number / Location				
Recorded By				
Witnessed By				

OTHER SERVICES1
OS1: DLL / MCFL / GR

OTHER SERVICES2
OS1:


Gamma Ray on Backup
HRDD Density Correction (HDRA)
-0.05
(G/C3)
0.45
Resistivity (HMIN)
0
(OHMM)
20
MAIN PASS 5'-100'
sc 4300
--CSG--
sc 4400
sc 4500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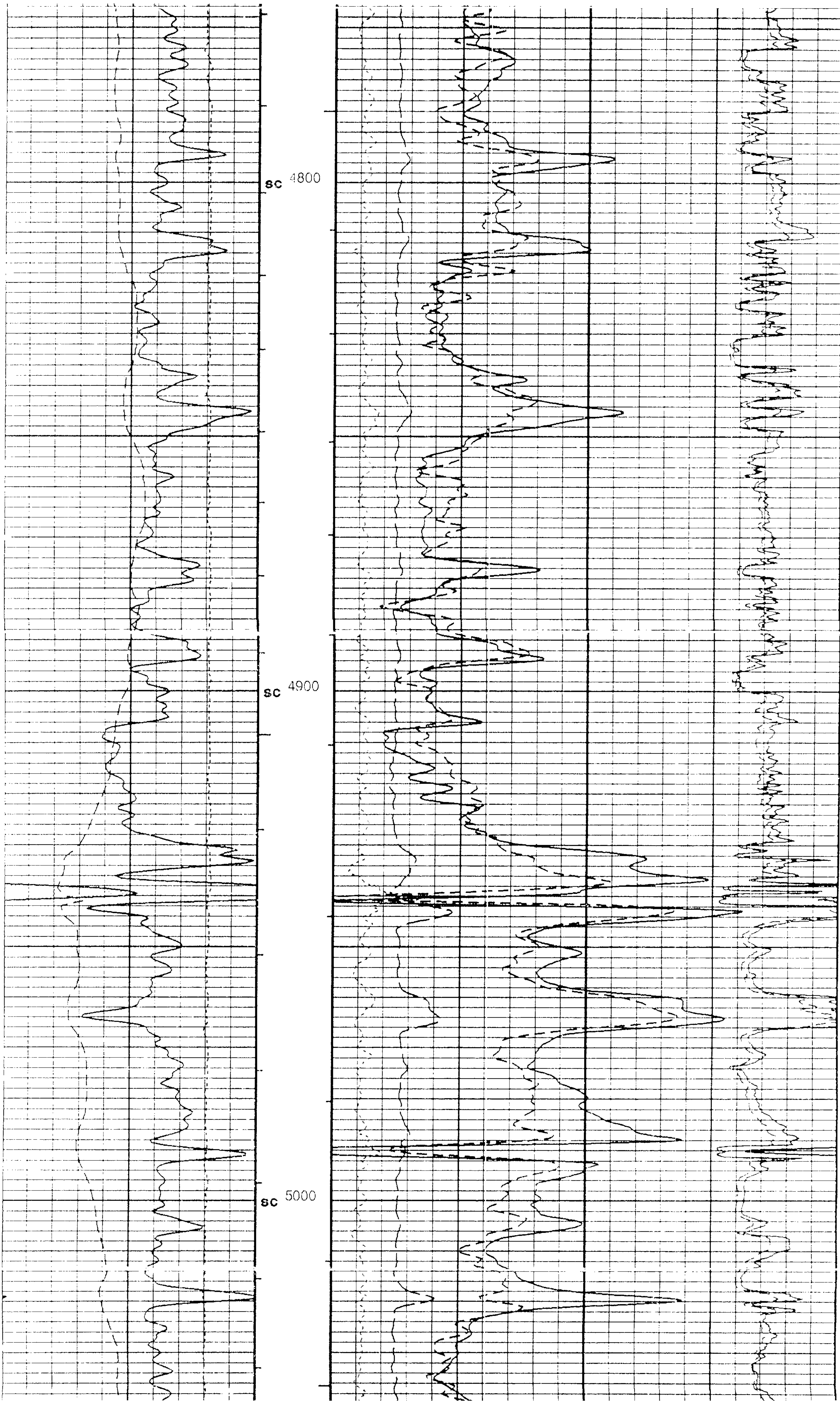
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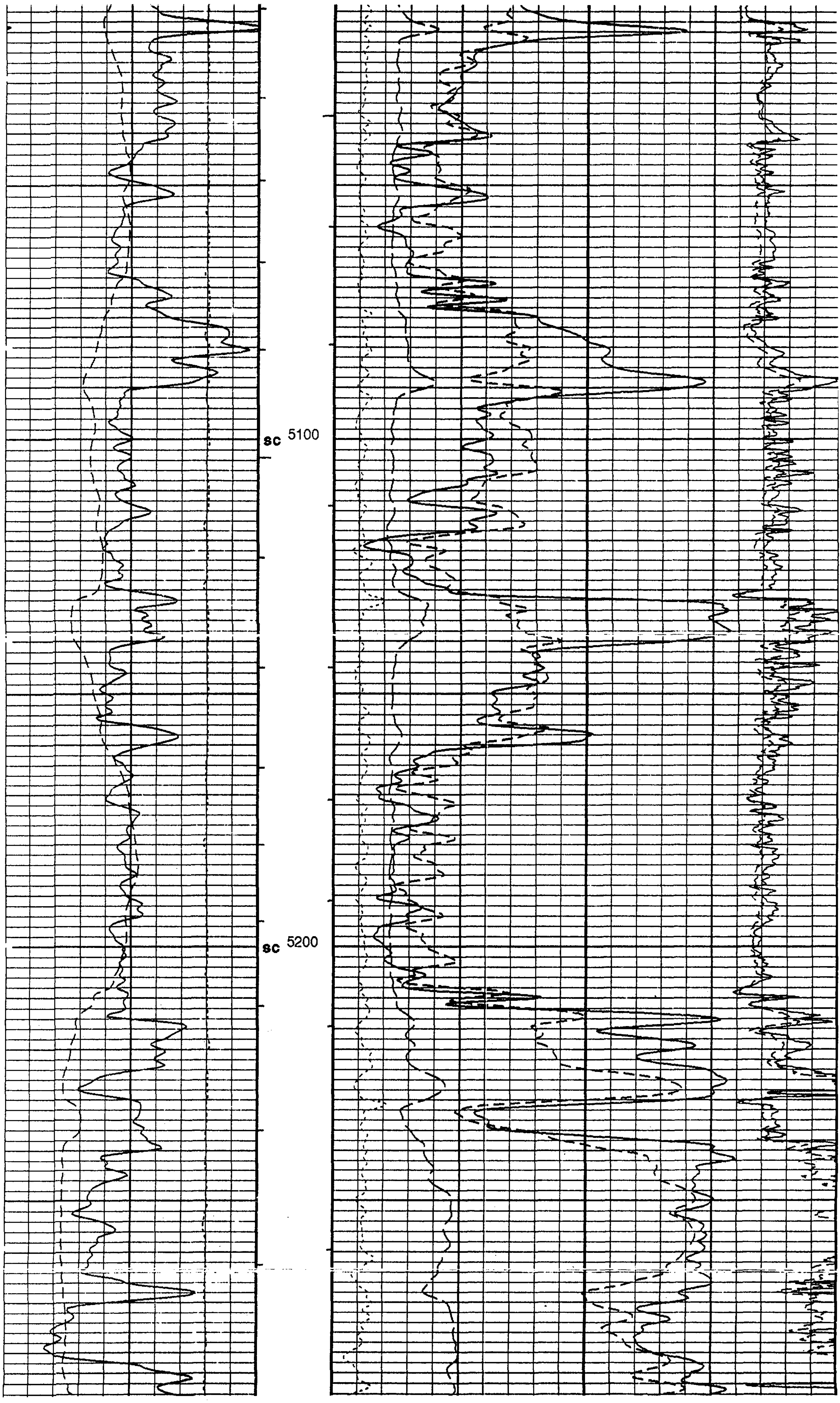
SC 5000



sc 5100
sc 5200

COMPANY: Texaco E & P Inc.

WELL: Bilbrey "30" Federal No. 5

FIELD: Lost Tank Delaware

COUNTY: Lea   STATE: New Mexico

COUNTY: Lea
Field: Lost Tank Delaware
Location: 1980' FSL & 1980' FEL
Well: Bilbrey "30" Federal No. 5
Company: Texaco E & P Inc

Schlumberger

Platform Express
Array Induction

LOCATION
1980' FSL & 1980' FEL

Elev.: K.B. 3691.8 F
G.L. 3680 F
D.F. 3690.8 F

Permanent Datum: GROUND LEVEL   Elev.: 3680 F
Log Measured From: KELLY BUSHING   11.8 F above Perm. Datum
Drilling Measured From: KELLY BUSHING

API Serial No.	SECTION	TOWNSHIP	RANGE
30-025-33647	30	21S	32E

Logging Date	18-DEC-1996			
Run Number	ONE			
Depth Driller	8916 F			
Schlumberger Depth	8902 F			
Bottom Log Interval	8895 F			
Top Log Interval	4364 F			
Casing Driller Size @ Depth	8.625 IN @ 4380 F		@	
Casing Schlumberger	4364 F			
Bit Size	7.875 IN			
Type Fluid In Hole	FRESH MUD			
MUD Density / Viscosity	8.7 LB/G	29 S		
MUD Fluid Loss / PH	8 C3	9		
MUD Source Of Sample	CIRCULATION TANK			
RM @ Measured Temperature	1.270 OHMM @ 49 DEGF		@	
RMF @ Measured Temperature	1.270 OHMM @ 49 DEGF		@	
RMC @ Measured Temperature	@		@	
Source RMF / RMC	MEASURED			
RM @ MRT / RMF @ MRT	0.568 @ 118	0.568 @ 118	@	@
Maximum Recorded Temperatures	118 DEGF			
Circulation Stopped / Time	18-DEC-1996	4:15		
Logger On Bottom / Time	18-DEC-1996	13:30		
Unit Number / Location	3031	HOBBS, NM		
Recorded By	B. H. BOEHME			
Witnessed By	TOBY BLACK			

	Run 1	Run 2	Run 3	Run 4
Logging Date				
Run Number				
Depth Driller				
Schlumberger Depth				
Bottom Log Interval				
Top Log Interval				
Casing Driller Size @ Depth	@		@	
Casing Schlumberger				
Bit Size				
Type Fluid In Hole				
MUD Density / Viscosity				
MUD Fluid Loss / PH				
MUD Source Of Sample				
RM @ Measured Temperature	@		@	
RMF @ Measured Temperature	@		@	
RMC @ Measured Temperature	@		@	
Source RMF / RMC				
RM @ MRT / RMF @ MRT	@	@	@	@
Maximum Recorded Temperatures				
Circulation Stopped / Time				
Logger On Bottom / Time				
Unit Number / Location				
Recorded By				
Witnessed By				

OTHER SERVICES1

OTHER SERVICES2

GRSE	Generalized Mud Resistivity Selection	AITH_RESIST	
GTSE	Generalized Temperature Selection	LINEAR_ESTIMATE	
HMPCO	HILT RTSC Measure points correction	NO	
HSCM	HILT Speed Correction Mode	TSCD_SpeedCorrect	
HSTI	STI Uses HILT Acceleration	YES	
MST	Mud Sample Temperature	55.00	DEGF
SHT	Surface Hole Temperature	68	DEGF
SPNV	SP Next Value	0	MV
TD	Total Depth	8903	FT

Speed Corrected - Depth Matched LOG

Output DLIS Files

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STRIP	HILTC .011	FN:13	CUST	18-DEC-1996 13:44

Output DLIS Files

DEFAULT	HILTC .011	FN:12	FIELD	18-DEC-1996 13:44
STRIP	HILTC .011	FN:13	CUST	18-DEC-1996 13:44

Speed Corrected - Depth Matched LOG

OP System Version: 7C0-428

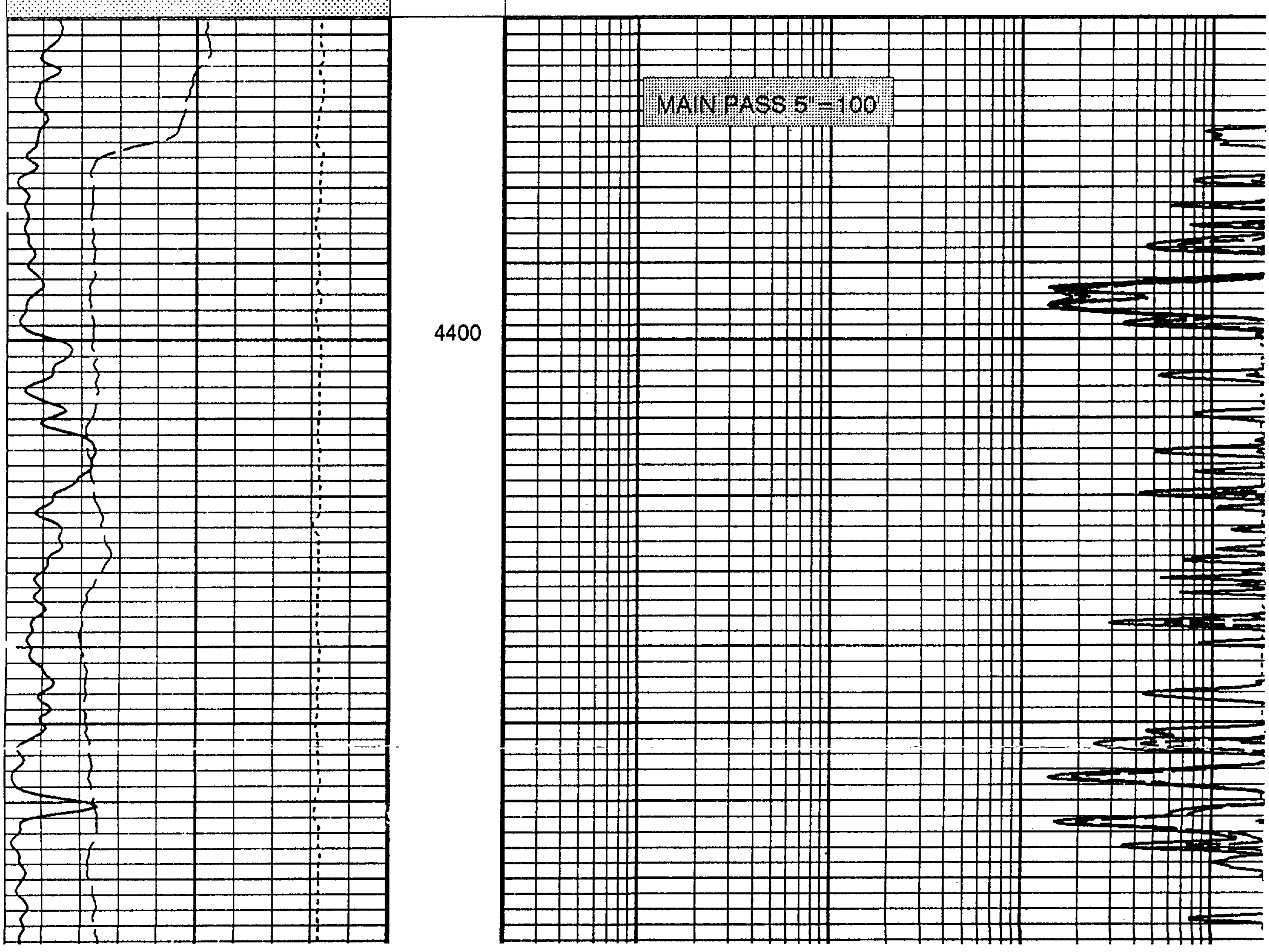
MBM

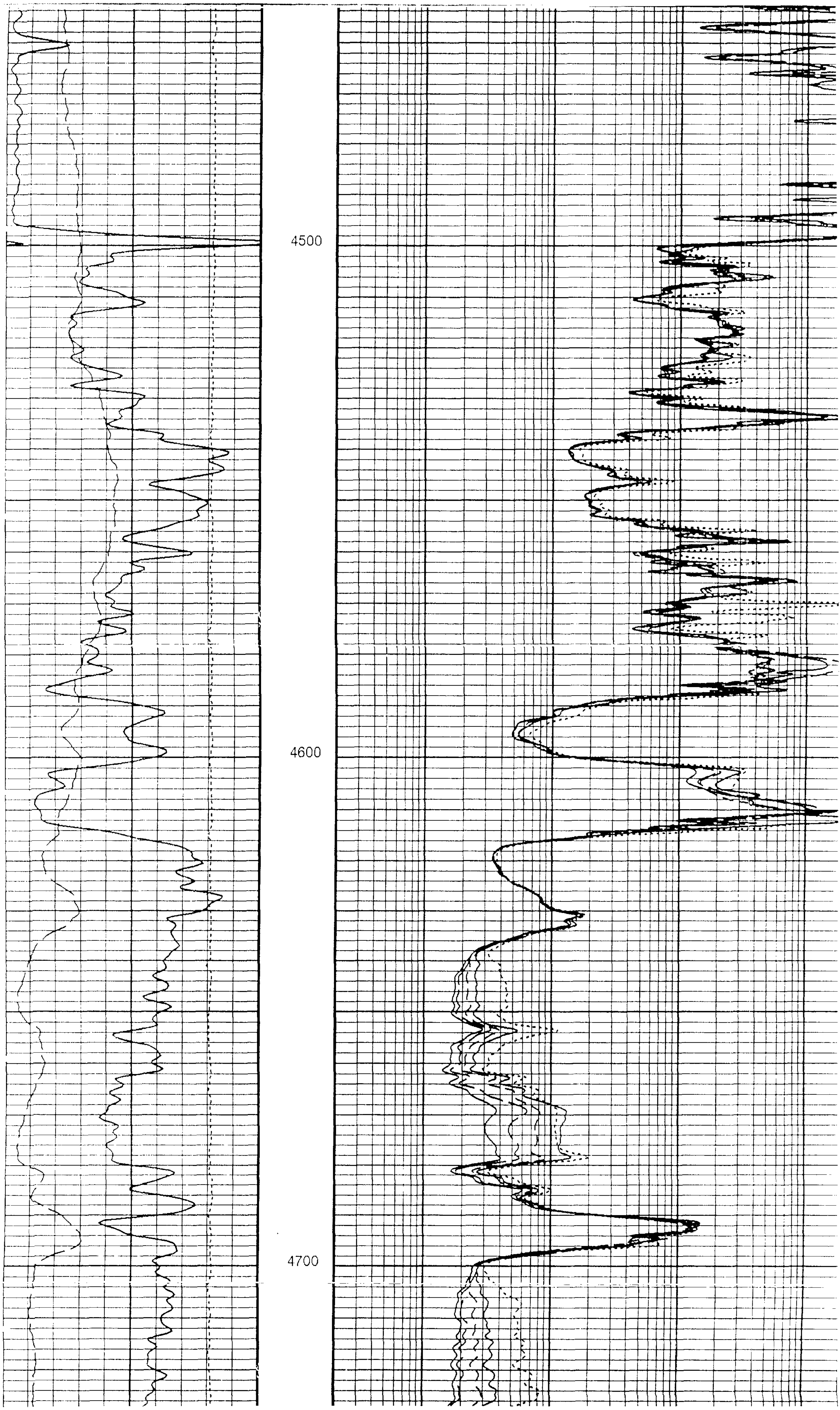
HILTB-CTS RPCAX-681 HOLEV RPCAX-681

PIP SUMMARY

Time Mark Every 60 S

Tension (TENS) (LBF)	10000	0	AIT-H 90 Inch Investigation (AHT90) (OHMM)	0.2	2000
SP (SP) (MV)	-80	20	AIT-H 60 Inch Investigation (AHT60) (OHMM)	0.2	2000
Gamma Ray (GR) (GAPI)	0	100	AIT-H 30 Inch Investigation (AHT30) (OHMM)	0.2	2000
Gamma Ray on Backup			AIT-H 20 Inch Investigation (AHT20) (OHMM)	0.2	2000
			AIT-H 10 Inch Investigation (AHT10) (OHMM)	0.2	2000

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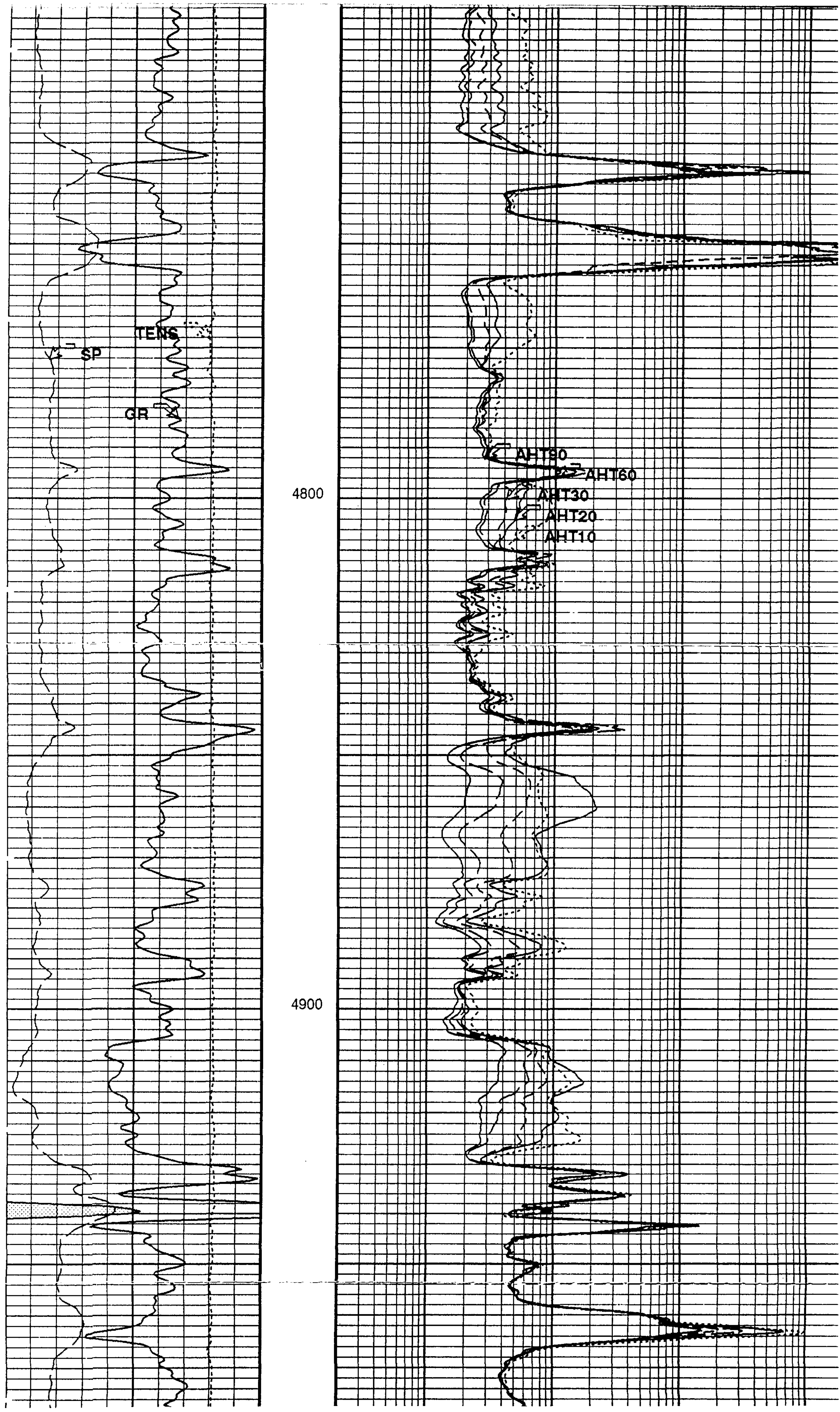
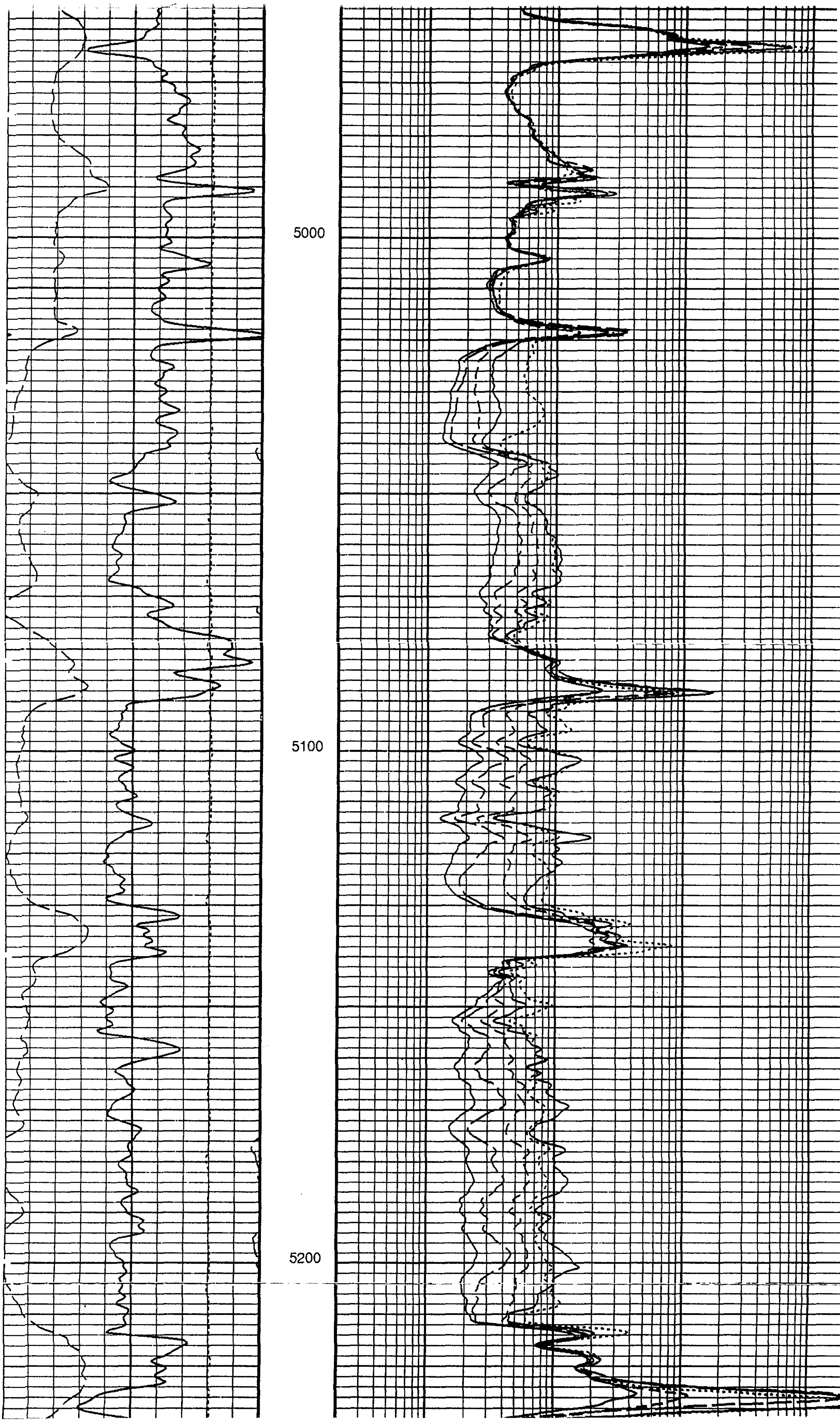


TENS
SP
GR
AHT90
AHT60
AHT30
AHT20
AHT10
4800
4900



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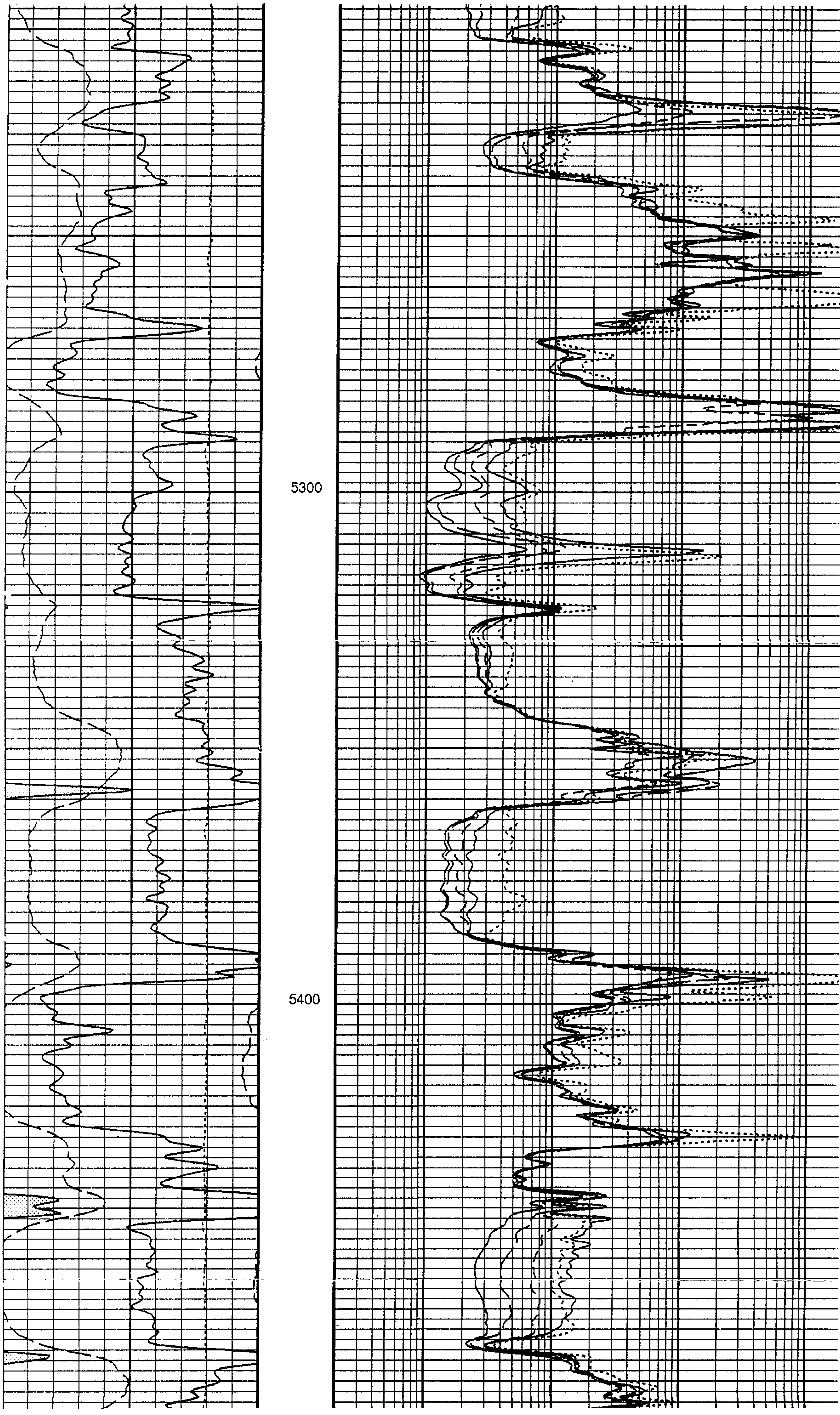
5200



5300
5400

COMPANY: Texaco E & P Inc.

WELL: Bilbrey "30" Federal No. 5

FIELD: Lost Tank Delaware

COUNTY: Lea   STATE: New Mexico

COUNTY: Lea
Field: Lost Tank Delaware
Location: 1980' FSL & 1980' FEL
Well: Bilbrey "30" Federal No. 5
Company: Texaco E & P Inc.

Schlumberger

Platform Express
Dual Laterolog
Micro-CFL / GR

LOCATION

1980' FSL & 1980' FEL		Elev.:	K.B. 3691.8 F
			G.L. 3680 F
			D.F. 3690.8 F
Permanent Datum:	GROUND LEVEL	Elev.:	3680 F
Log Measured From:	KELLY BUSHING	11.8 F	above Perm. Datum
Drilling Measured From:	KELLY BUSHING		

API Serial No	SECTION	TOWNSHIP	RANGE
30-025-33647	30	21S	32E

Logging Date	18-DEC-1996			
Run Number	ONE			
Depth Driller	8916 F			
Schlumberger Depth	8902 F			
Bottom Log Interval	8895 F			
Top Log Interval	4364 F			
Casing Driller Size @ Depth	8.625 IN	@ 4380 F		@
Casing Schlumberger	4364 F			
Bit Size	7.875 IN			
Type Fluid In Hole	FRESH MUD			
MUD Density / Viscosity	8.7 LB/G	29 S		
Fluid Loss / PH	8 C3	9		
Source Of Sample	CIRCULATION TANK			
RM @ Measured Temperature	1.270 OHMM	@ 49 DEGF		@
RMF @ Measured Temperature	1.270 OHMM	@ 49 DEGF		@
RMC @ Measured Temperature		@		@
Source RMF / RMC	MEASURED			
RM @ MRT / RMF @ MRT	0.568 @ 118	0.568 @ 118	@	@
Maximum Recorded Temperatures	118 DEGF			
Circulation Stopped / Time	18-DEC-1996	4:15		
Logger On Bottom / Time	18-DEC-1996	13:30		
Unit Number / Location	3031	HOBBS, NM		
Recorded By	B. H. BOEHME			
Witnessed By	TOBY BLACK			

	Run 1	Run 2	Run 3	Run 4
Logging Date				
Run Number				
Depth Driller				
Schlumberger Depth				
Bottom Log Interval				
Top Log Interval				
Casing Driller Size @ Depth	@		@	
Casing Schlumberger				
Bit Size				
Type Fluid In Hole				
MUD Density / Viscosity				
Fluid Loss / PH				
Source Of Sample				
RM @ Measured Temperature	@		@	
RMF @ Measured Temperature	@		@	
RMC @ Measured Temperature	@		@	
Source RMF / RMC				
RM @ MRT / RMF @ MRT	@	@	@	@
Maximum Recorded Temperatures				
Circulation Stopped / Time				
Logger On Bottom / Time				
Unit Number / Location				
Recorded By				
Witnessed By				

OTHER SERVICES1
OS1: CNT / LDT / GR

OTHER SERVICES2
OS1:

DEFAULT	HILTC .011	FN:12	FIELD	18-DEC-1996 13:44
STRIP	HILTC .011	FN:13	CUST	18-DEC-1996 13:44

Output DLIS Files

DEFAULT	HILTC .011	FN:12	FIELD	18-DEC-1996 13:44
STRIP	HILTC .011	FN:13	CUST	18-DEC-1996 13:44

Speed Corrected - Depth Matched LOG

OP System Version: 7C0-428

MBM

HILTB-CTS	RPCAX-681	HOLEV	RPCAX-681

PIP SUMMARY

Time Mark Every 60 S

AIT-H 90 Inch Investigation (AHT90)
0.2 (OHMM) 20

Tension (TENS)
10000 (LBF) 0

AIT-H 60 Inch Investigation (AHT60)
0.2 (OHMM) 20

SP (SP)
-80 (MV) 20

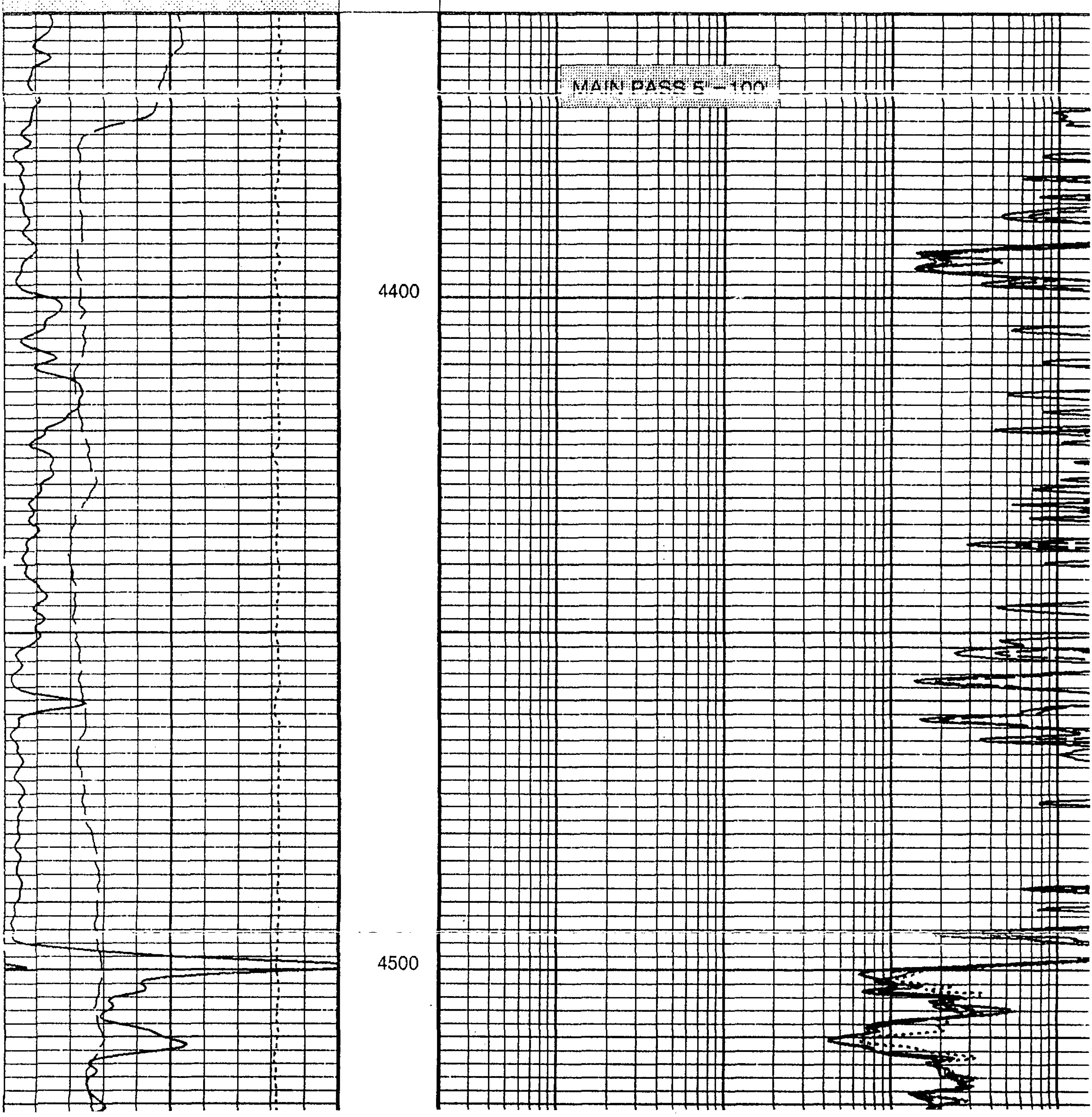
AIT-H 30 Inch Investigation (AHT30)
0.2 (OHMM) 20

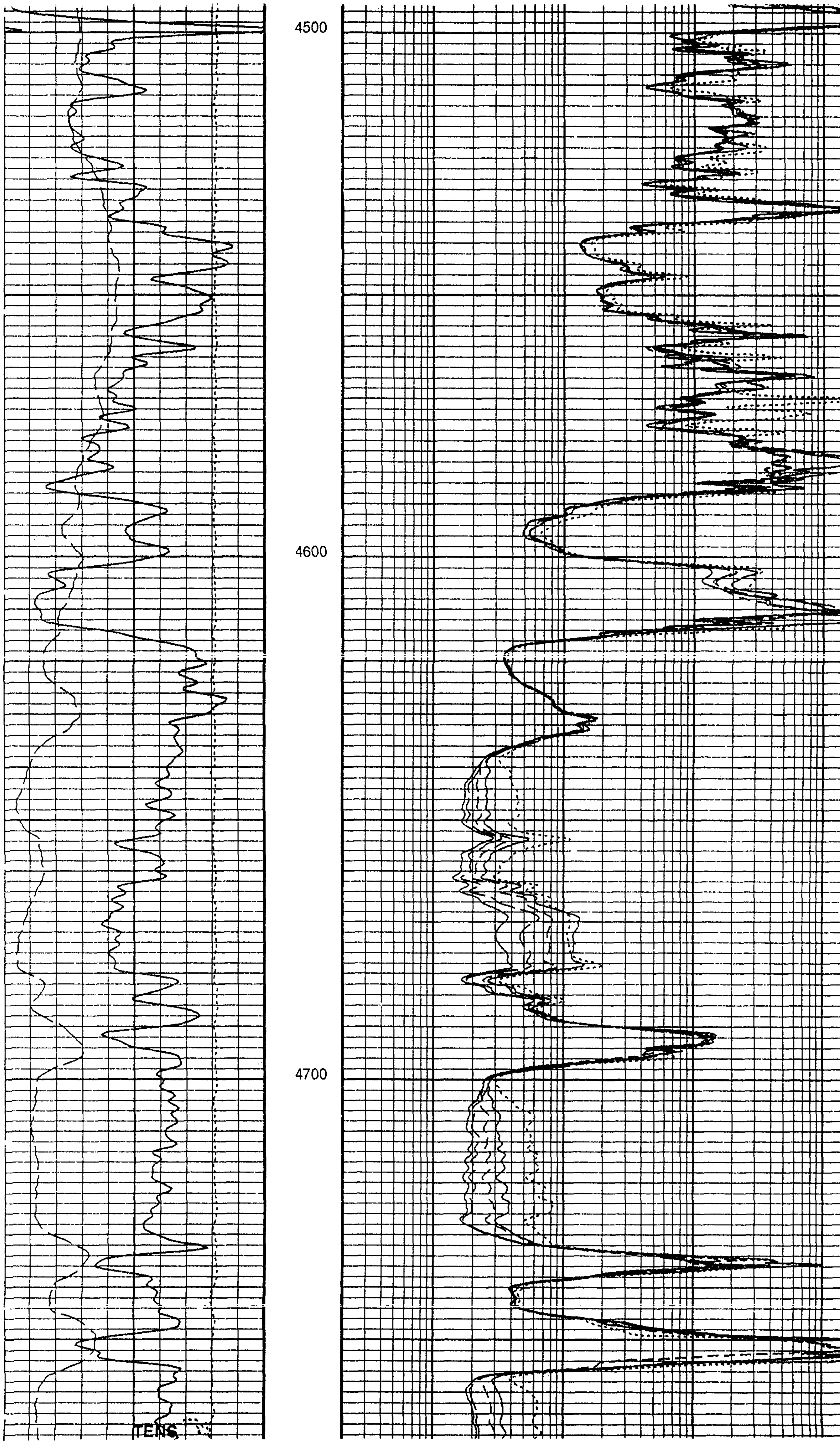
Gamma Ray (GR)
0 (GAPI) 100

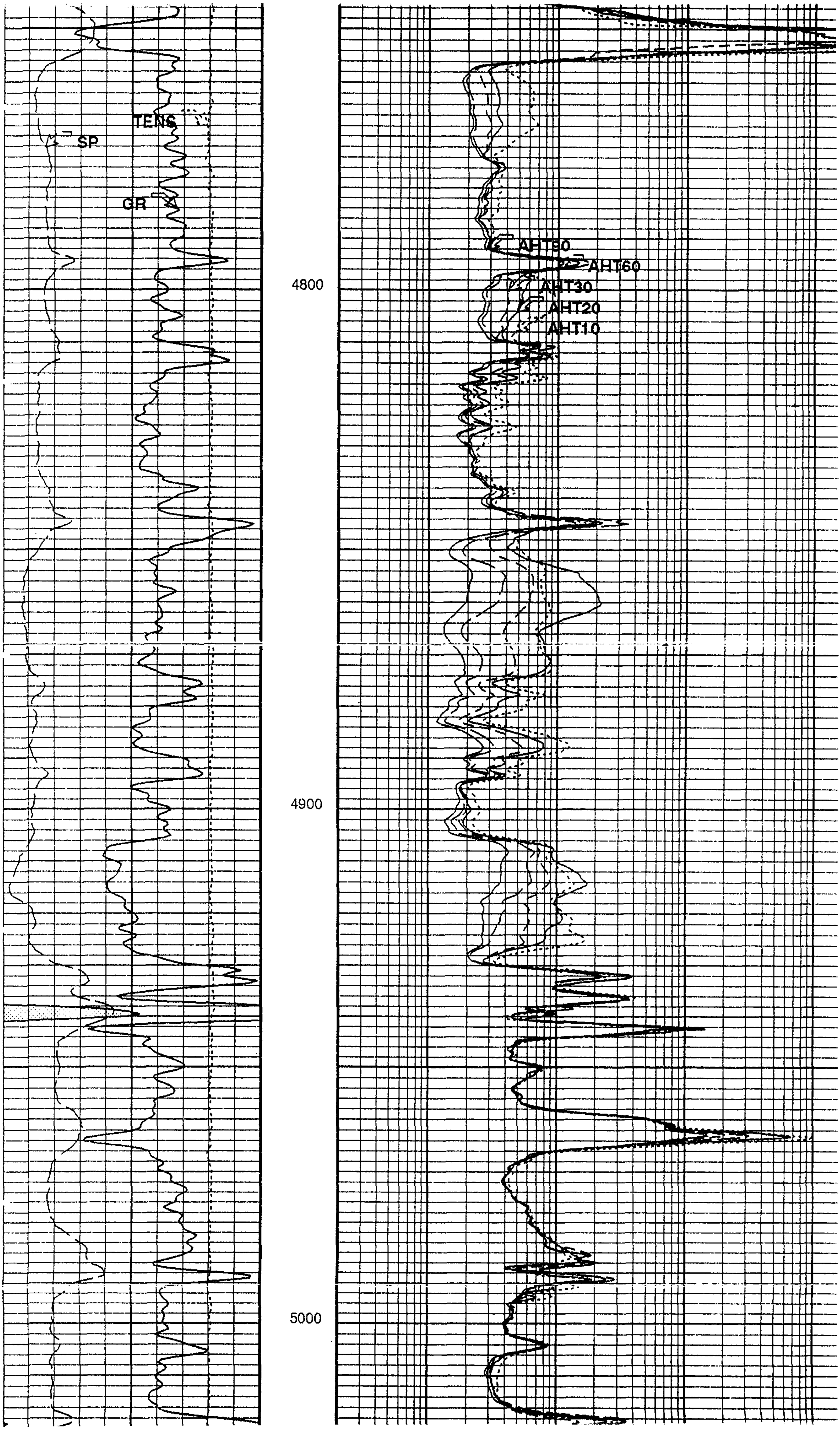
AIT-H 20 Inch Investigation (AHT20)
0.2 (OHMM) 20

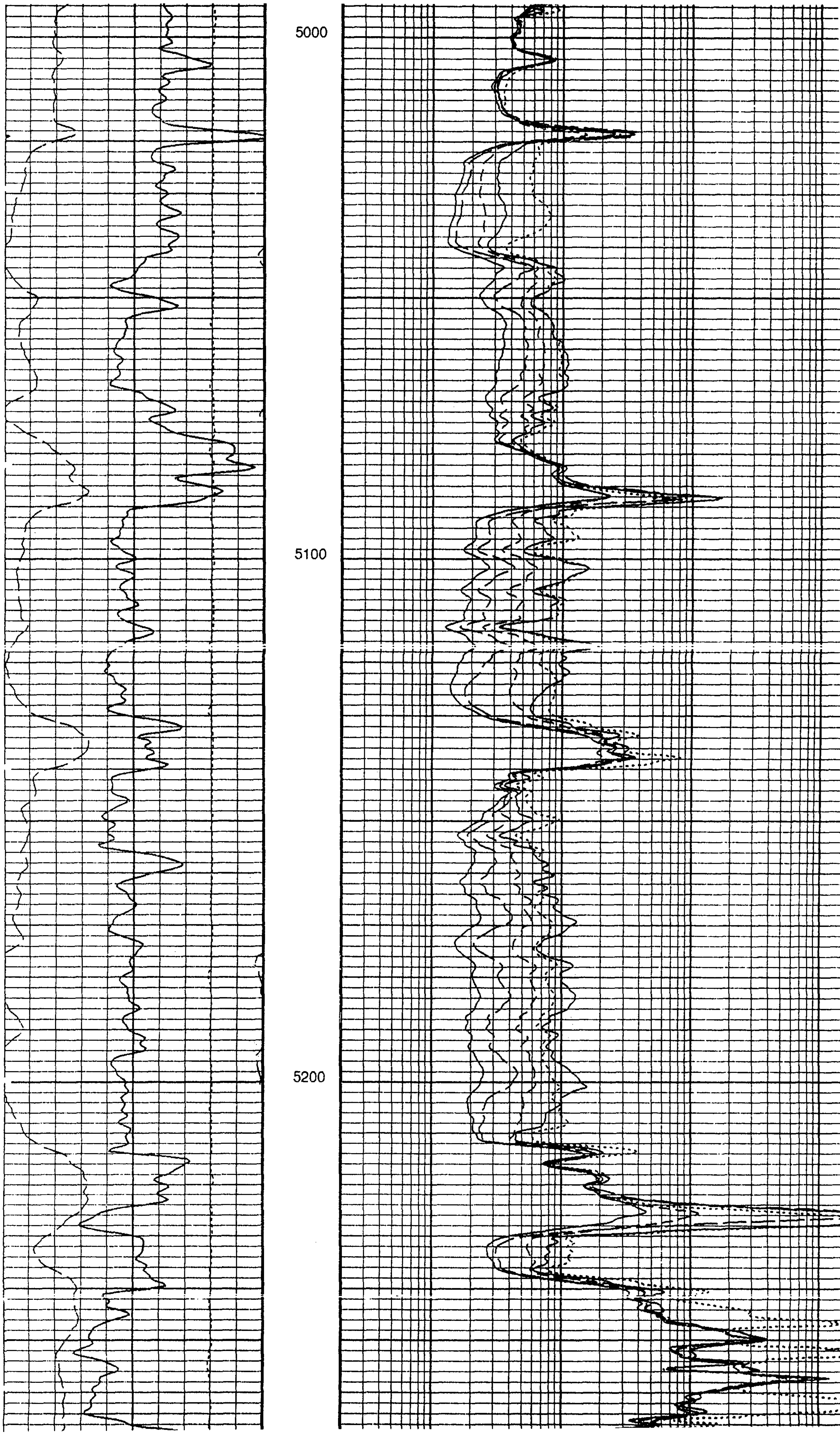
Gamma Ray on Backup

AIT-H 10 Inch Investigation (AHT10)
0.2 (OHMM) 20




4500
4600
4700
TENS


TENS
SP
GR
AHT90
AHT60
AHT30
AHT20
AHT10
4800
4900
5000

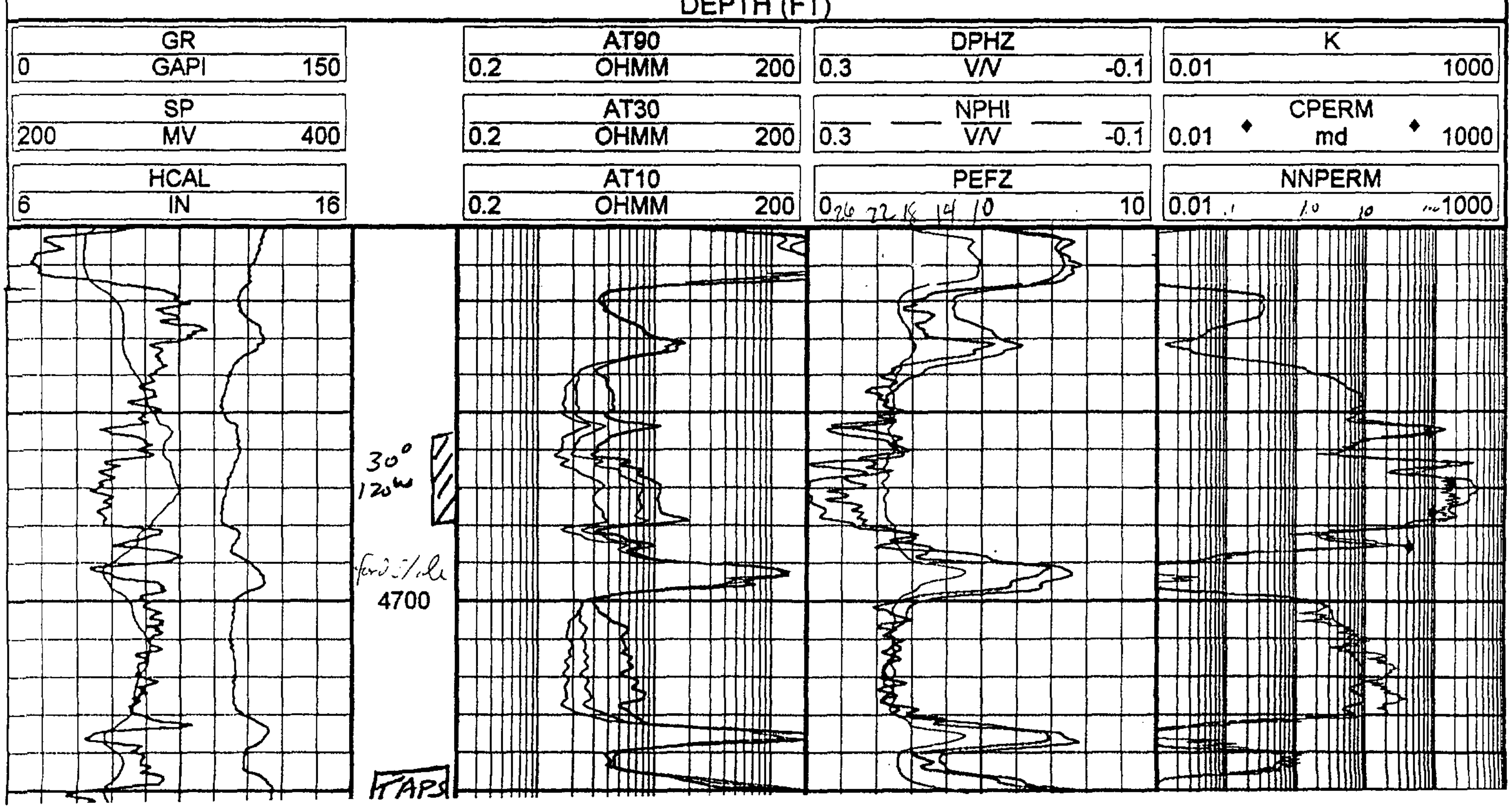

5000
5100
5200

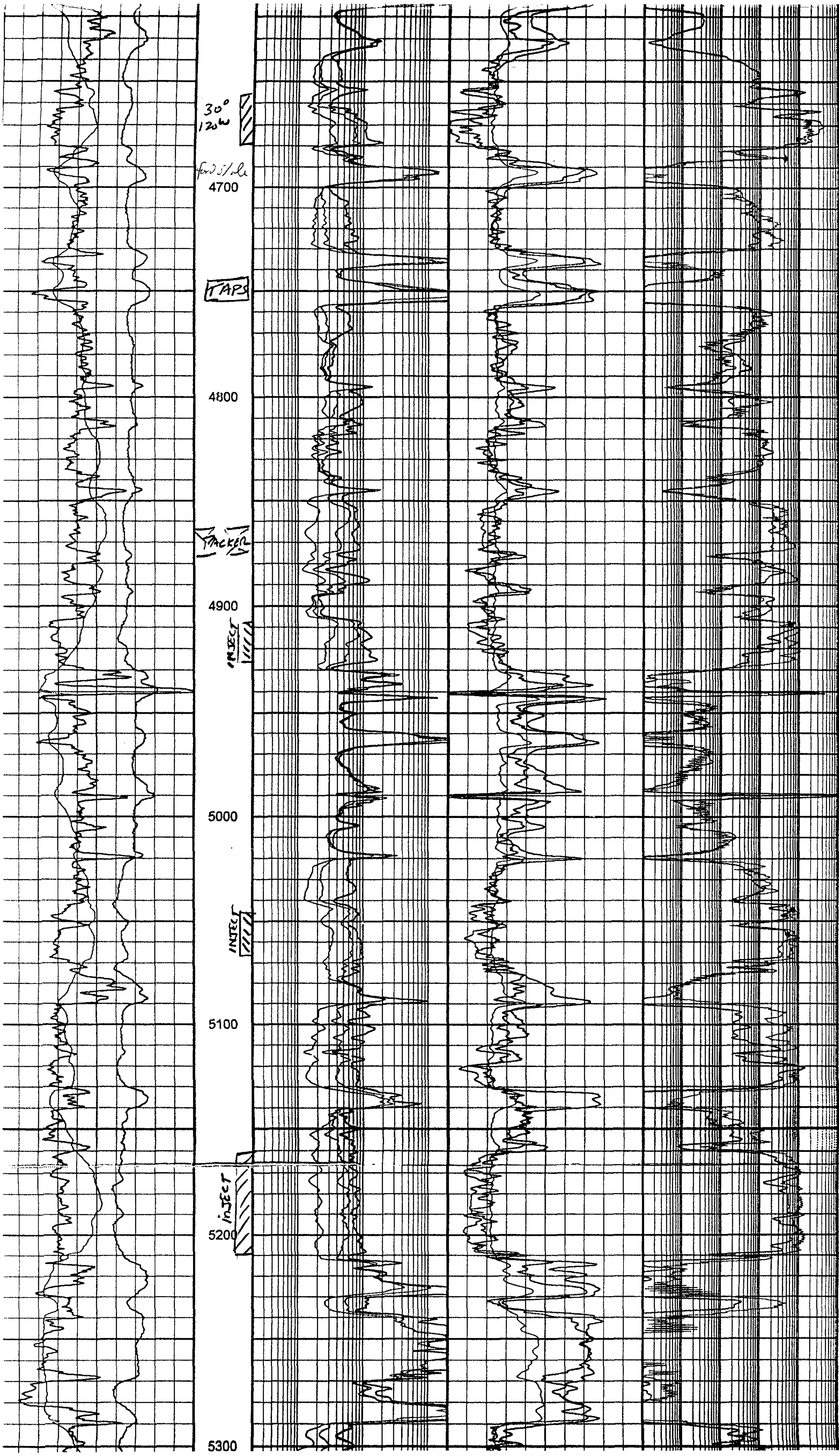
Company	Texaco E & P Inc.
Well	Bilbrey "30" Federal No. 5
Field	Lost Tank Delaware
County	
State	New Mexico
Country	
Location	1980' FSL & 1980' FEL

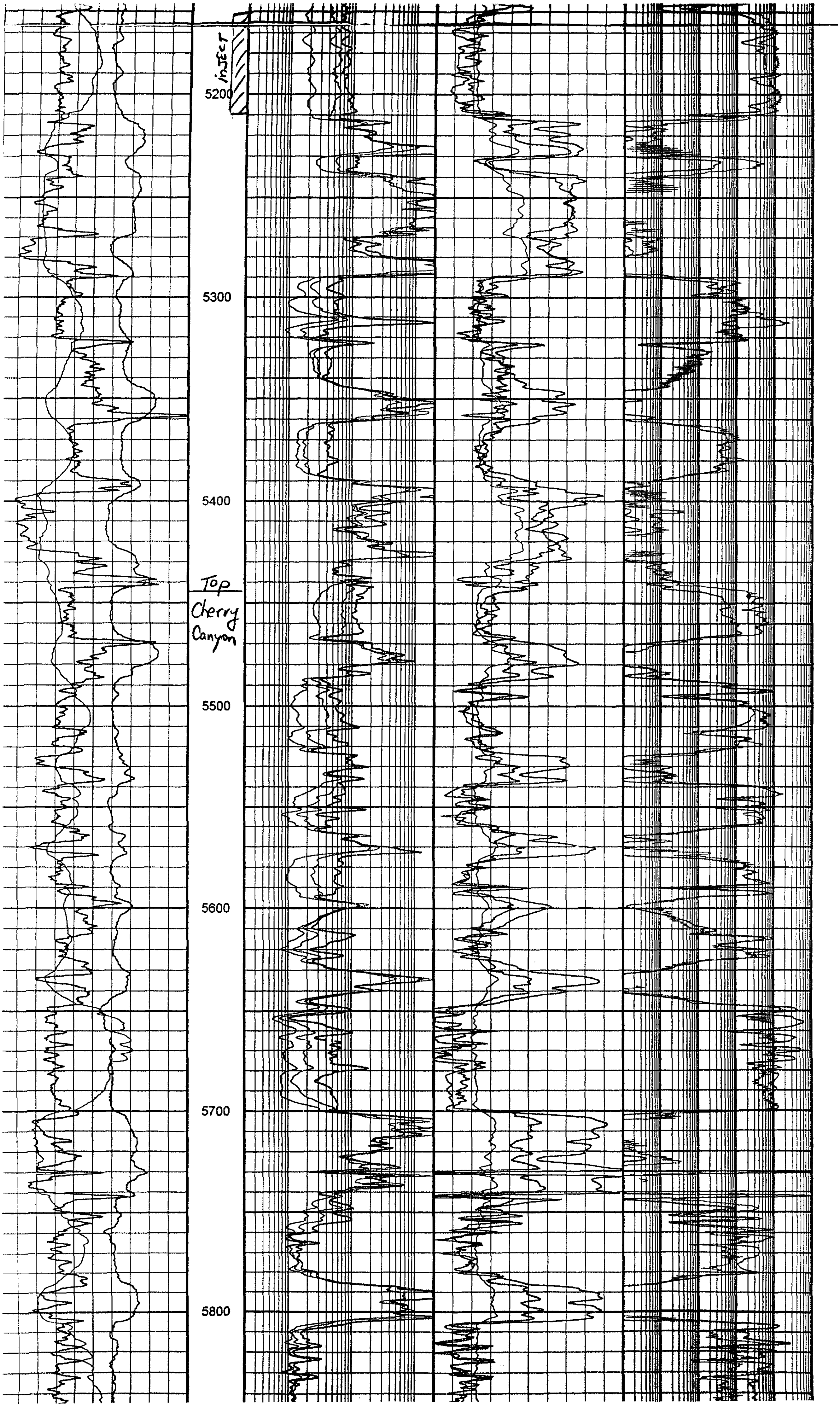
Section		Township		Range		API Num	30-025-33647
Permanent Datum				Elevation		K.B.	3691.8
Log Measured From		,		Above Perm Datum		D.F.	
Drilling Meas From						G.L.	3680.

	Run 1	Run 2	Run 3
Date			
Depth - Driller	8916.		
Depth - Logger	8903.		
Btm Log Interval			
Top Log Interval			
Casing - Driller			
Casing - Logger			
Bitsize	7.875		
Type Fluid in Hole	FRESH MUD		
Dens. /Visc.	8.6999/ 29.		
pH / Fluid Loss	9. / 8.		
Source of Sample	CIRCULATION TANK		
Rm @ Meas. Temp	28.6 @ 55.		
Rmf @ Meas. Temp	28.6 @ 55.		
Rmc @ Meas. Temp			
Source: Rmf / Rmc	MEASUR/		
Rm @ BHT			
Max. Rec. Temp.	118.		

Bilbrey "30" Federal No. 5
9 Sep 1998 @ 18:32
DEPTH (FT)




30°
120w
4700
TAPS
4800
PACKER
4900
INJECT
5000
INJECT
5100
INJECT
5200
5300


inject
5200
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5400
Top
Cherry
Canyon
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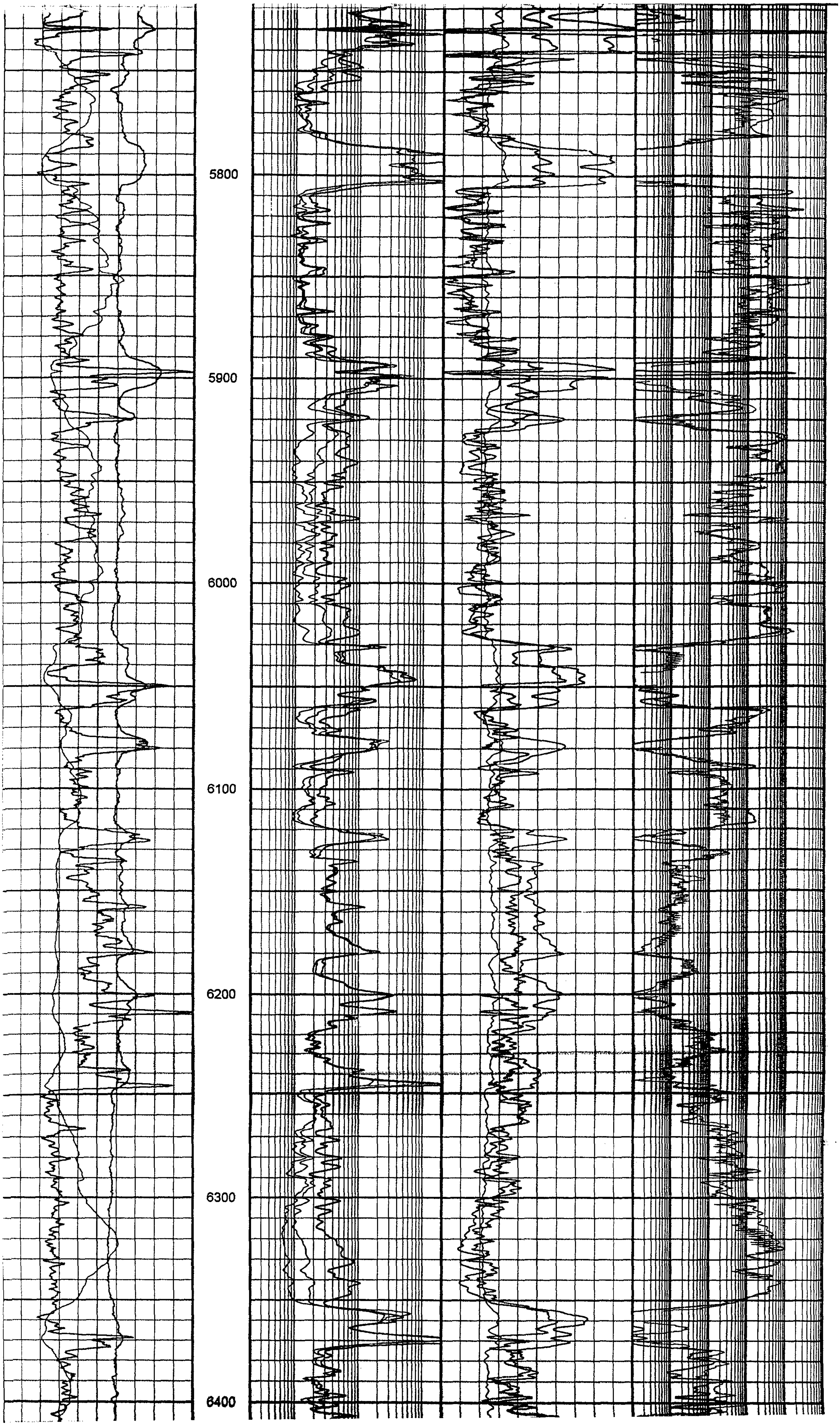
5700
5800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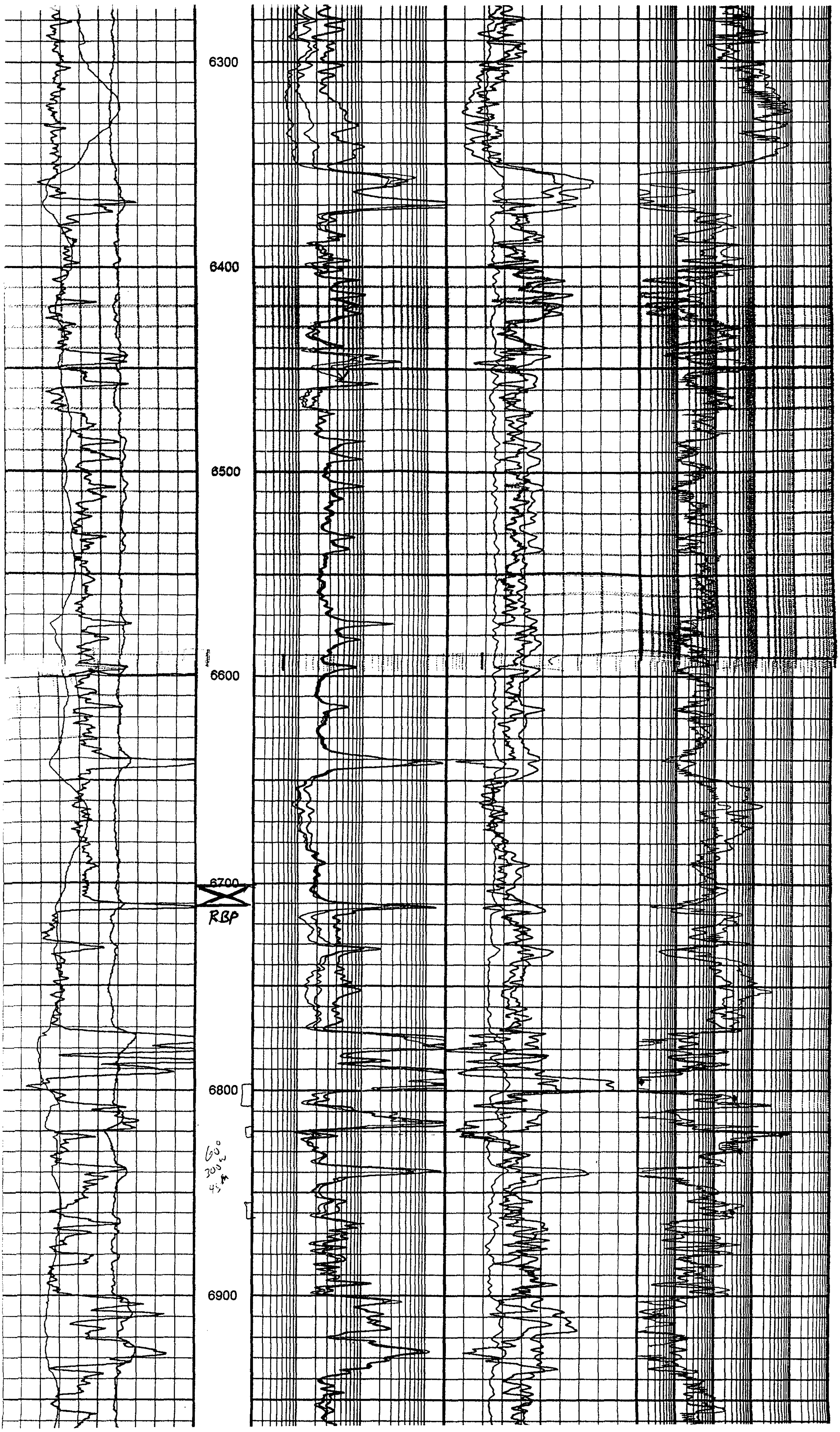
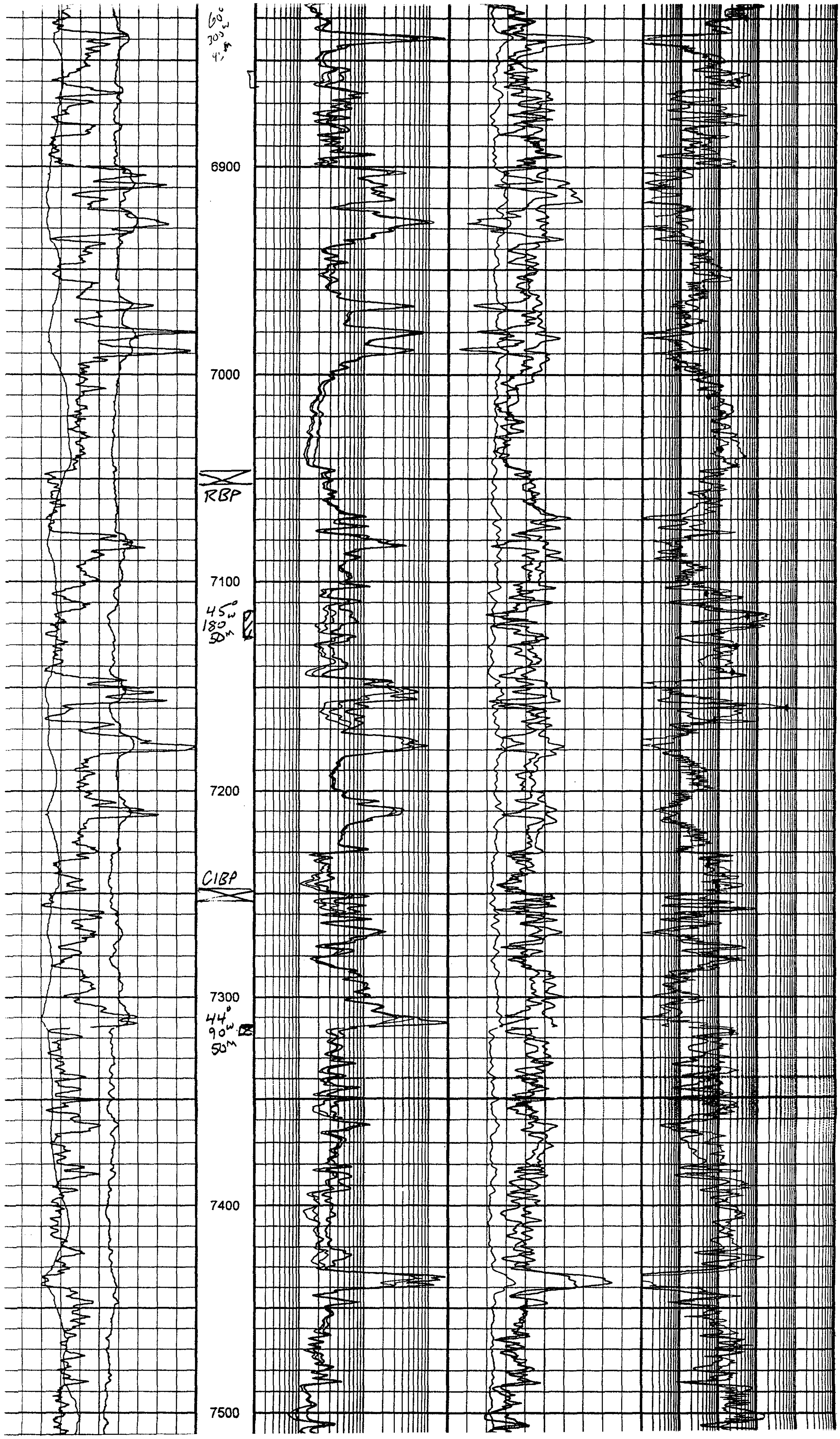
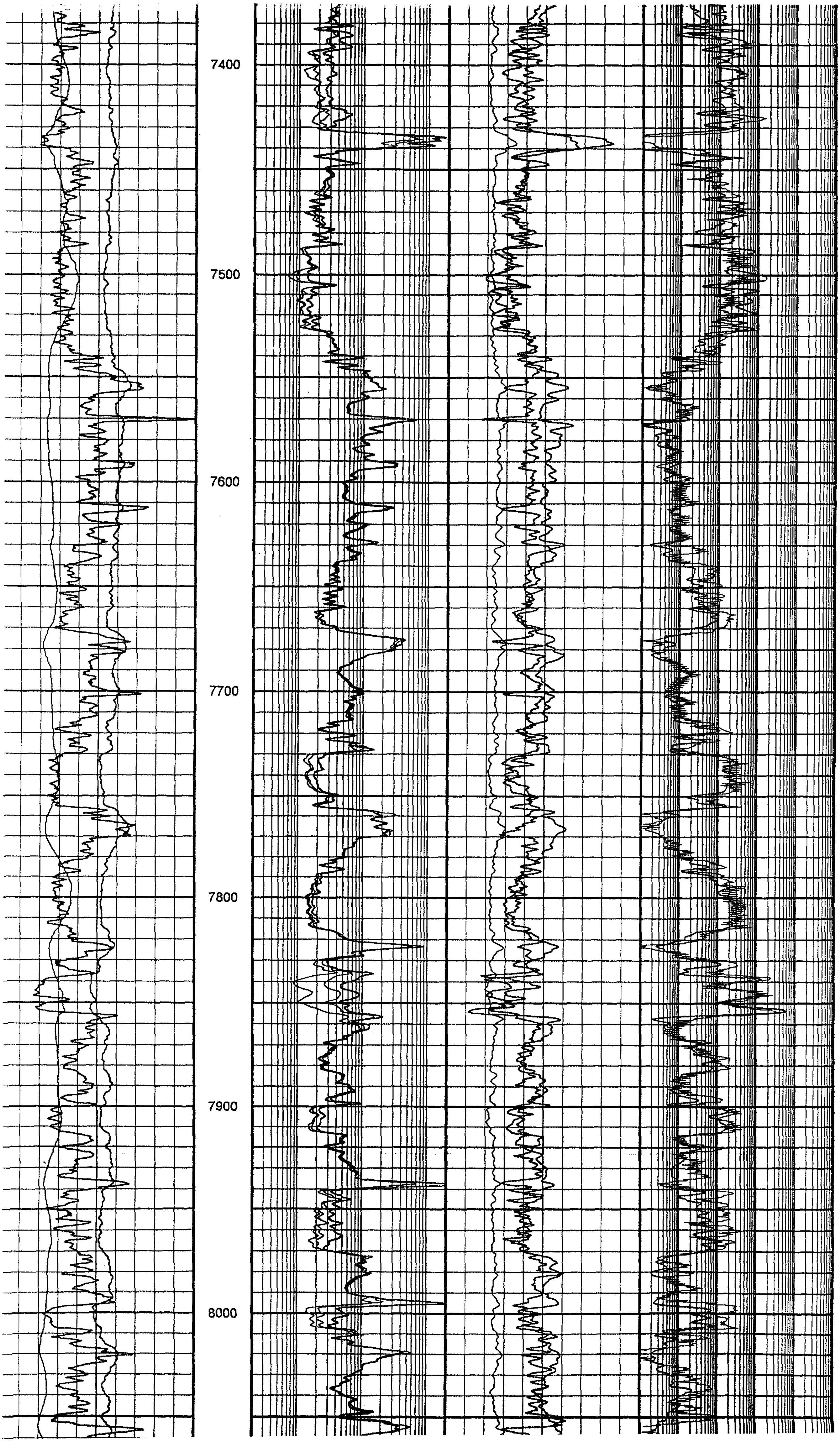
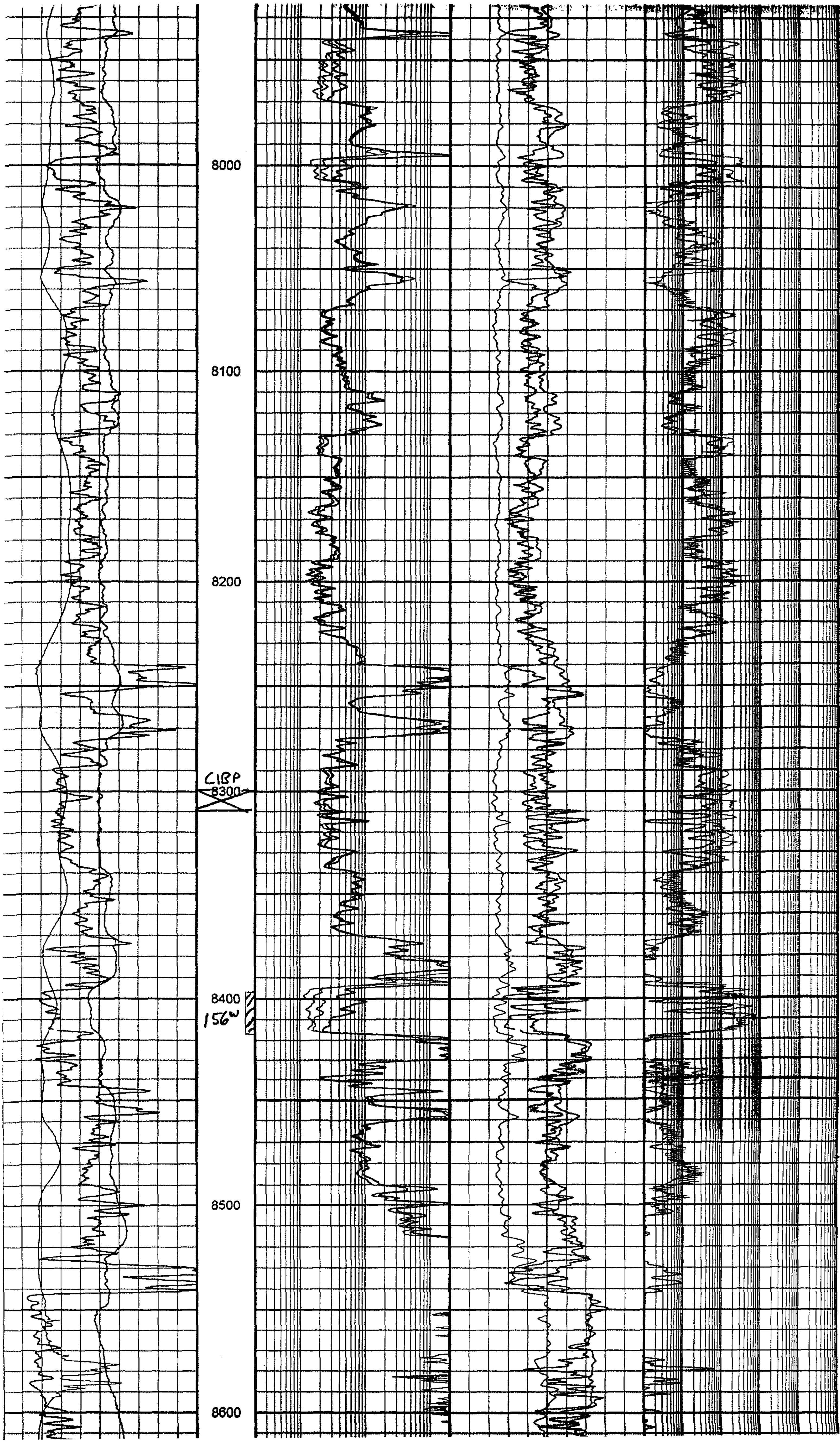
5900
6000
6100
6200
6300
6400

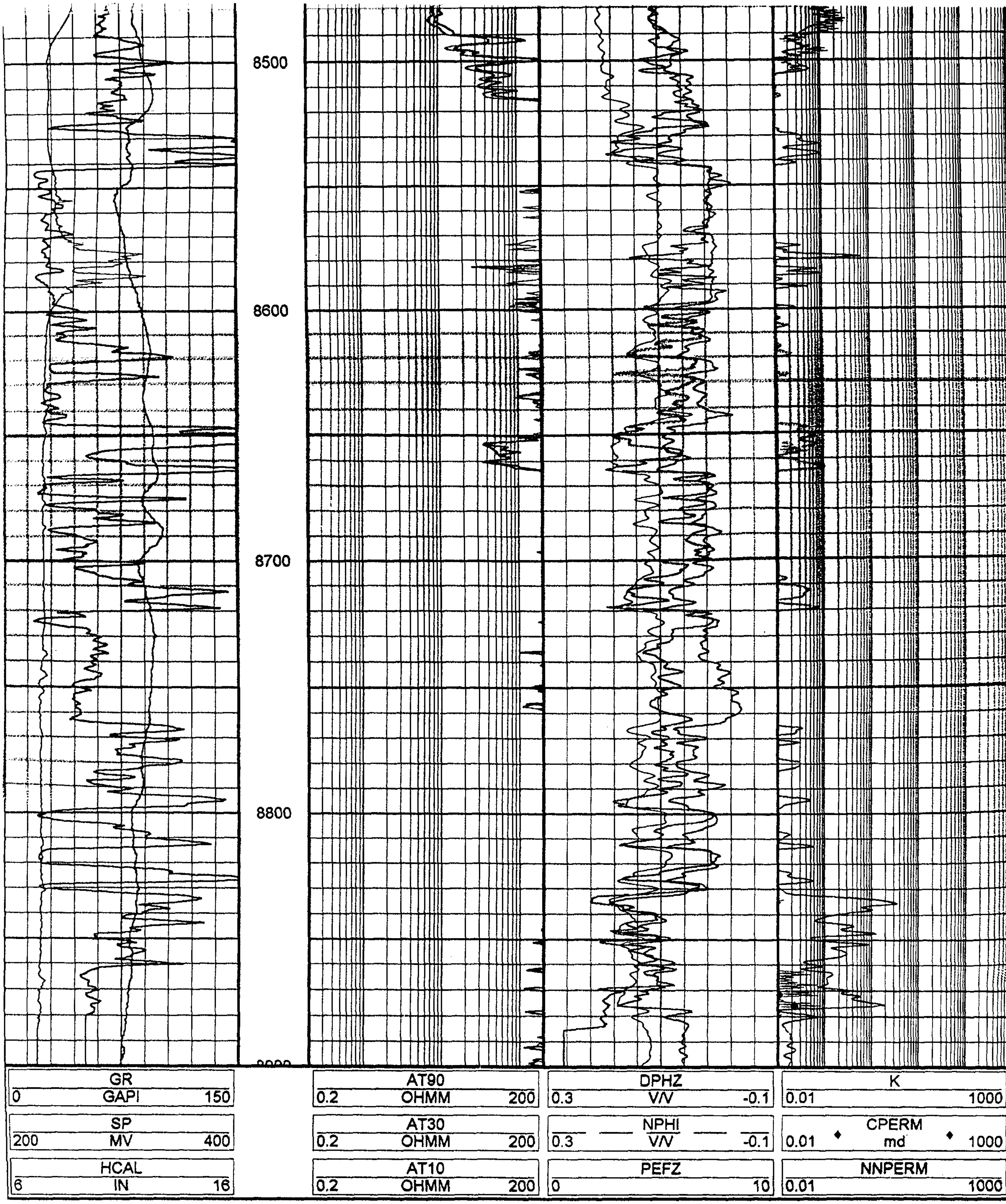

6300
6400
6500
6600
6700
RBP
6800
60°
300w
6900



60°
300°w
4' m
6900
7000
RBP
7100
45°
180°w
50m
7200
CIBP
7300
44°
90°w
50m
7400
7500


7400
7500
7600
7700
7800
7900
8000


8000
8100
8200
CIBP
8300
8400
156w
8500
8600



8500
8600
8700
8800
GR
0 GAPI 150
SP
200 MV 400
HCAL
6 IN 16
AT90
0.2 OHMM 200
AT30
0.2 OHMM 200
AT10
0.2 OHMM 200
DPHZ
0.3 V/V -0.1
NPHI
0.3 V/V -0.1
PEFZ
0 10
K
0.01 1000
CPERM
0.01 md 1000
NNPERM
0.01 1000

XIII. Proof of Notice

AFFIDAVIT OF PUBLICATION

State of New Mexico,
County of Lea.

I, KATHI BEARDEN

Publisher

of the Hobbs Daily News-Sun, a daily newspaper published at Hobbs, New Mexico, do solemnly swear that the clipping attached hereto was published once a week in the regular and entire issue of said paper, and not a supplement thereof for a period.

of 1 weeks.

Beginning with the issue dated

October 7 1998

and ending with the issue dated

October 7 1998

Kathi Bearden

Publisher

Sworn and subscribed to before

me this 6th day of

October 1998

Jodi Henson

Notary Public.

My Commission expires
October 18, 2000
(Seal)

LEGAL NOTICE
October 7, 1998

Notice is hereby given of the application of Texaco Exploration & Production, Inc., (Attention: Tim G. Miller, Operating Unit Manager, P.O. Box 730, Hobbs, New Mexico, 88240, Telephone (505)393-7191), to the New Mexico Oil Conservation Commission, Energy and Minerals Department, for approval of the following well(s) to be utilized as both a producing oil well and a salt water disposal well for the purpose of disposing of produced fluids.

Texaco E & P, Inc. plans to re-complete the subject well as both a producing oil well and a salt water disposal well in the Delaware formation in the following well:

Lease/Unit Name: Bilbrey 30 Federal

Well Numbers and Location(s): #5-Unit Letter J, 1980' FSL & 1980' FEL, Section 30, T-21-S, R-30-E, Lea County, New Mexico.

The producing formation is the Delaware at a depth from 4654 feet to 4680 feet below the surface of the earth.

The disposal formation will be the Delaware at a depth from 4910 feet to 5210 feet below the surface of the earth. Expected maximum injection rate is 300 barrels of water per day and expected maximum injection pressure is equivalent to 1000 pounds per square inch at the surface. Injection will be below a packer at approximately 4800 feet. The system will be closed. This work is part of an ongoing development project. Interested parties must file objections or requests for hearing with the New Mexico Oil Conservation Division, P.O. Box 2088, Santa Fe, New Mexico, 87501, within fifteen (15) days of this publication.

#16185

This newspaper is duly qualified to publish legal notices or advertisements within the meaning of Section 3, Chapter 167, Laws of 1937, and payment of fees for said publication has been made.

01101308000 01527046

Texaco Inc.
205 E. Bender
a/c# 386561
Hobbs, NM 88240

Bilbrey 30 Federal #5 - Proposed
1980' FSL & 1980' FEL, J-30-21S-32E

Name: B30_5 ID: 30025336470000 Type: DEL Date: 19981201
KB: 11.8 TD: 8916.0 PBTD: 6700.0 Comp Date: 19970326