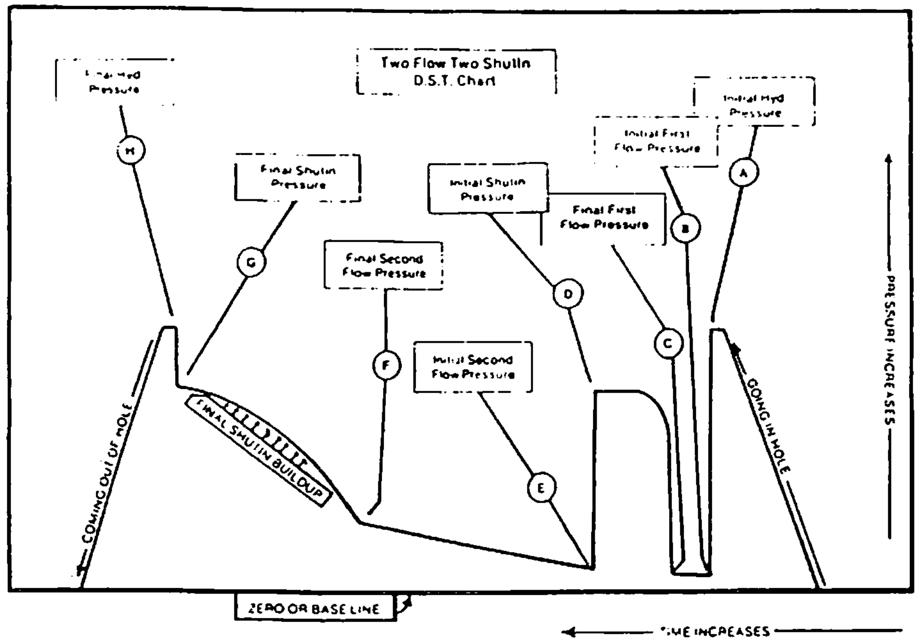
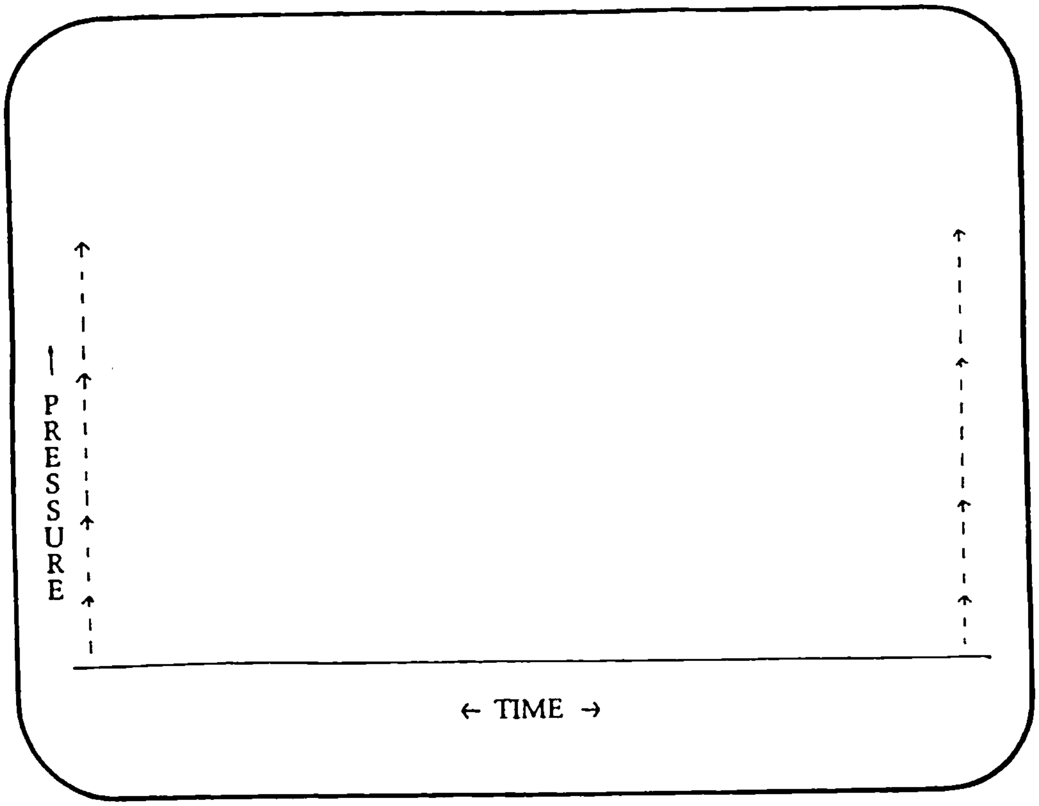
FIELD GUIDE TO DRILL STEM TESTING AND CHART INTERPRETATION

TRILOBITE TESTING, INC.

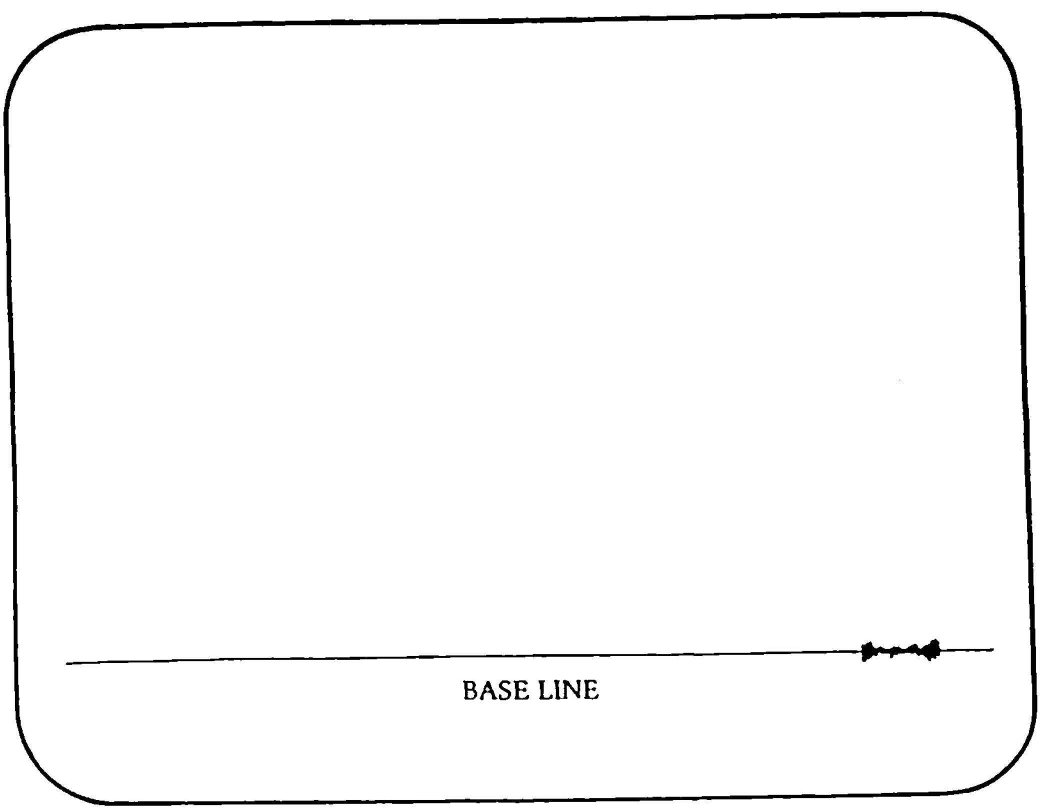


Drill Stem Test Chart Components

1. Base Line - The base line is a horizontal line scribed near the bottom of the chart. This base line is put on at the surface at atmospheric pressure. The procedure for scribing this base line is outlined in our Recorder Manuals.
2. Pressure Lines - The pressure line increases from the base line vertically up.
3. Time Line - The time line increases from right to left on all AK-1 recorders. This is a horizontal line.
4. Going-In-Hole-Line. This is a line that measures the hydrostatic pressure of the well bore fluid while going in hole. This hydrostatic pressure increases from atmospheric at the surface to the maximum hydrostatic pressure at bottom of the hole. This is marked point A. Initial Hydrostatic Fluid Pressure.
5. Initial First Flow Pressure - This is the point when the tool is first opened and the formation pressure is flowing the rat hole mud into the drill stem. Labeled point B.
6. Final First Flow - After tool has been opened for the first flow period. This is the last point of the first flow period. Labeled point C.
7. Initial Shut-in Pressure - This is the point at the end of the initial shut-in period. Labeled point D.
8. Initial Second Flow Pressure - After the tool has been opened for the final flow period this is the first point on this final flow and is Labeled point E.
9. Final Second Flow Pressure - After the tool has been opened for the final flow period this is the last point on this final flow and is Labeled point F.
10. Final Shut-in Pressure - This is the point at the end of the final shut-in pressure buildup curve labeled point G. This is the point at which the tool is pulled loose.
11. Final Hydrostatic Fluid Pressure - This is the point where the packer is pulled loose and the recorder is measuring the final hydrostatic pressure and is labeled point H. NOTE: There are occasions where the final hydrostatic pressure is less than the initial hydrostatic pressure. The reason for this is that the mud may have dropped in annulus during test. This mud will go into a low pressure zone somewhere above the packer.
12. Coming-Out-Of-Hole-Line - This is recording the hydrostatic fluid pressure from a maximum at bottom to atmospheric at the surface.



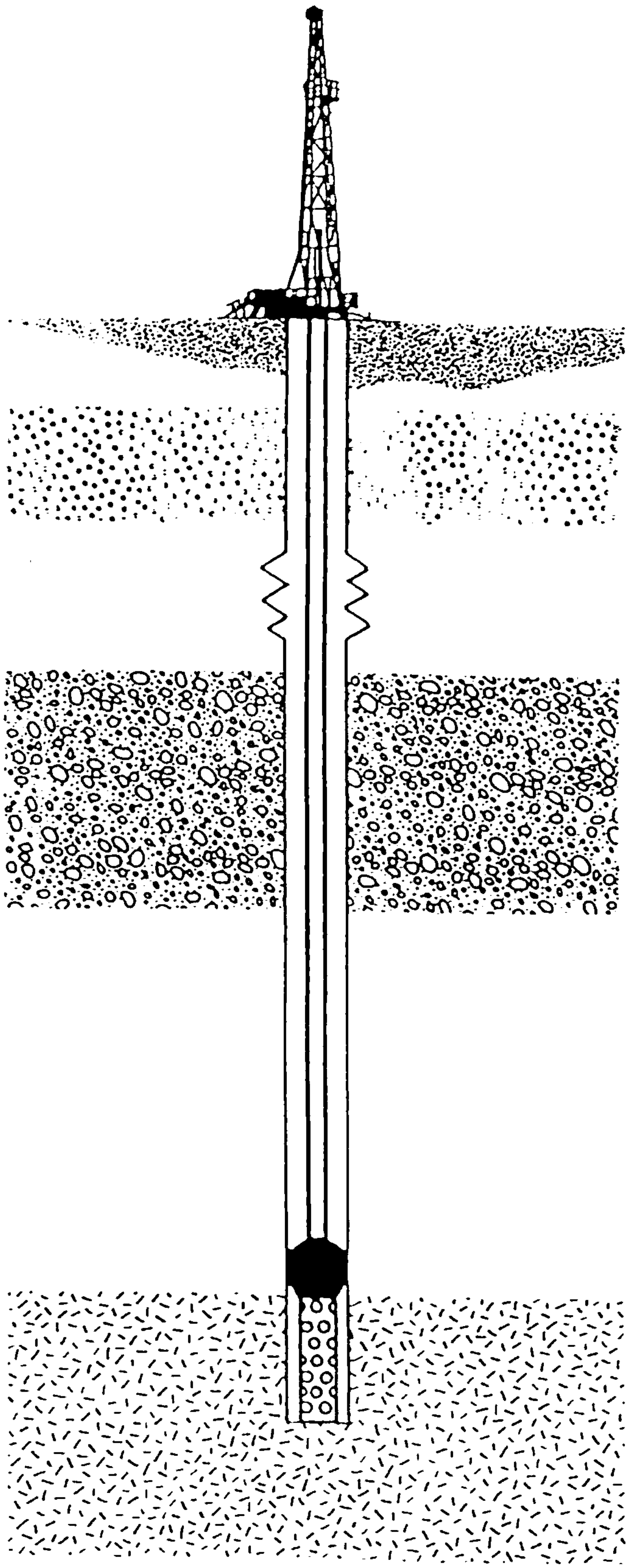
DST CHART
Chart is a pressure vs. time grapl



ASSEMBLING TEST STRING AT SURFACE
Chart loaded into recorder
Base line marked
Clock started
Recorder loaded
Records atmospheric pressure

CONTENTS

BENEFITS



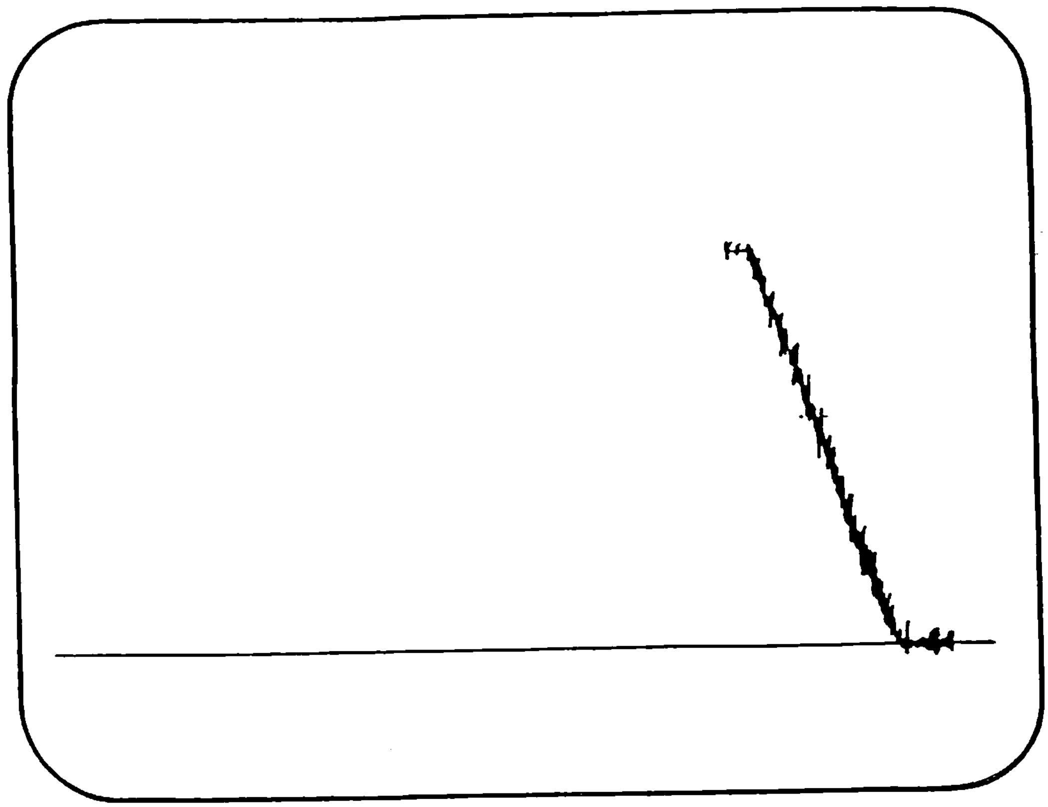
Why Drill Stem Tests are Run

A. To provide basic physical facts about a zone or zones of interest.

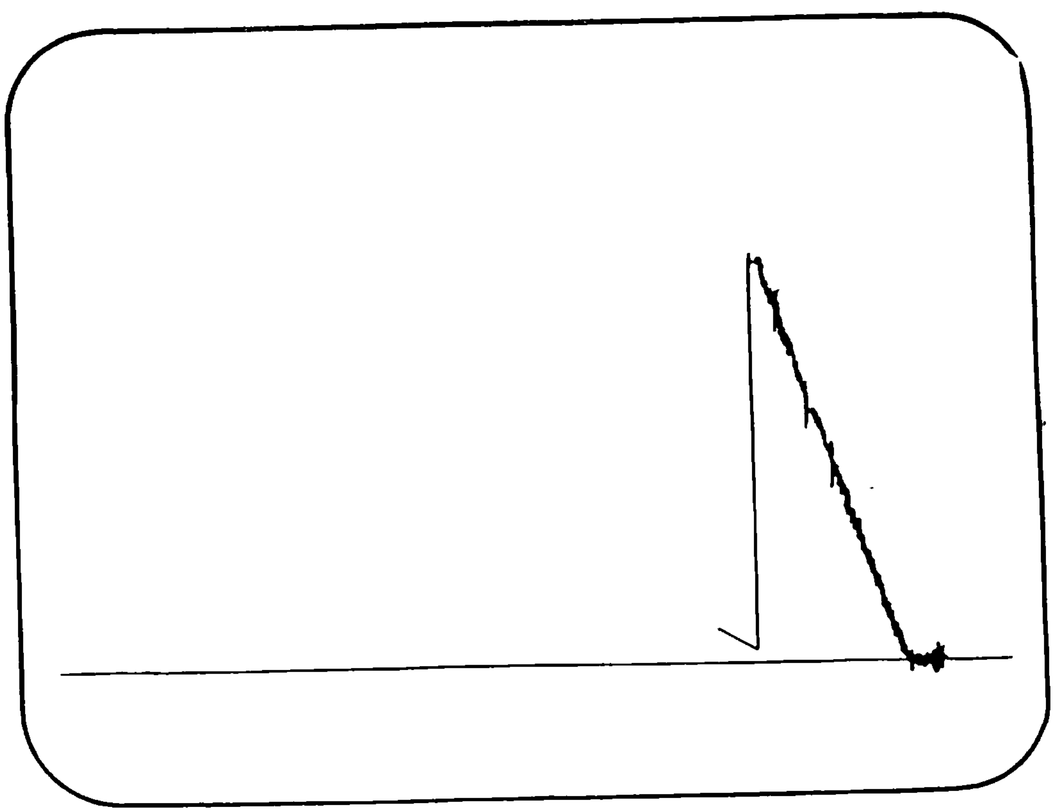
B. To help determine the productivity of a well, (during the drilling stage) before production-casing is set.

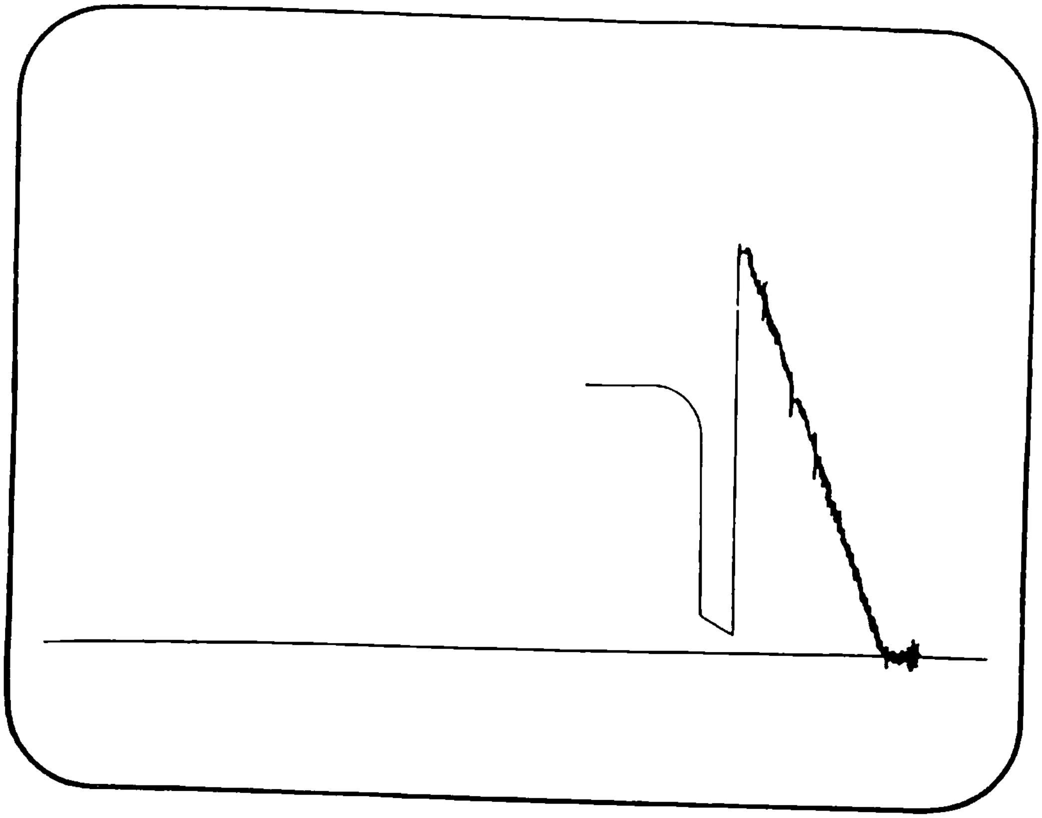
C. Formation Evaluation
  (1) Productive Capacity of Formation
  (2) Type of Fluids or Gas Produced
  (3) Initial Reservoir Pressure
  (4) Presence of Depletion
  (5) Effective Permeability
  (6) Formation Damage
  (7) Anomaly Presence
  (8) P.V.T. Analysis
  (9) Bottom Hole Temperature
  (10) Radius of Investigation

RUNNING TOOL IN HOLE
Pressure increase measures weight of mud in hole, when test depth achieved, hydrostatic pressure recorded.

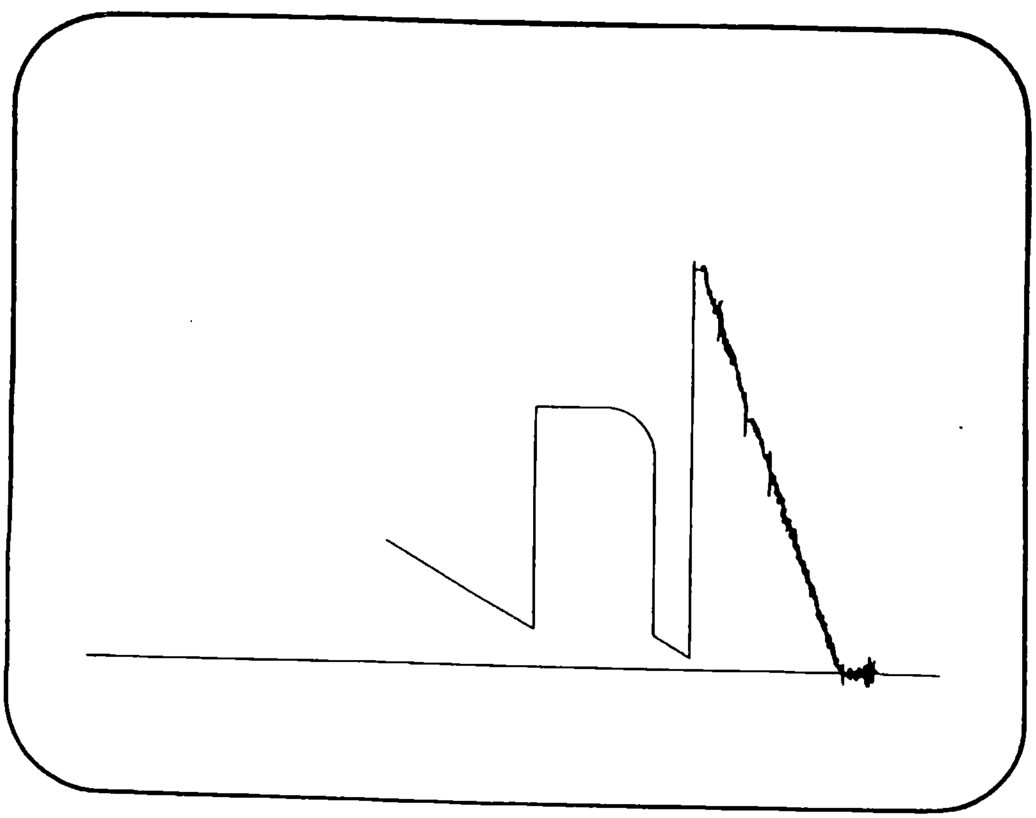


PREFLOW
Test inverval opened to atmospheric pressure. Records pressure during preflow (weight of fluid which has flowed into pipe).





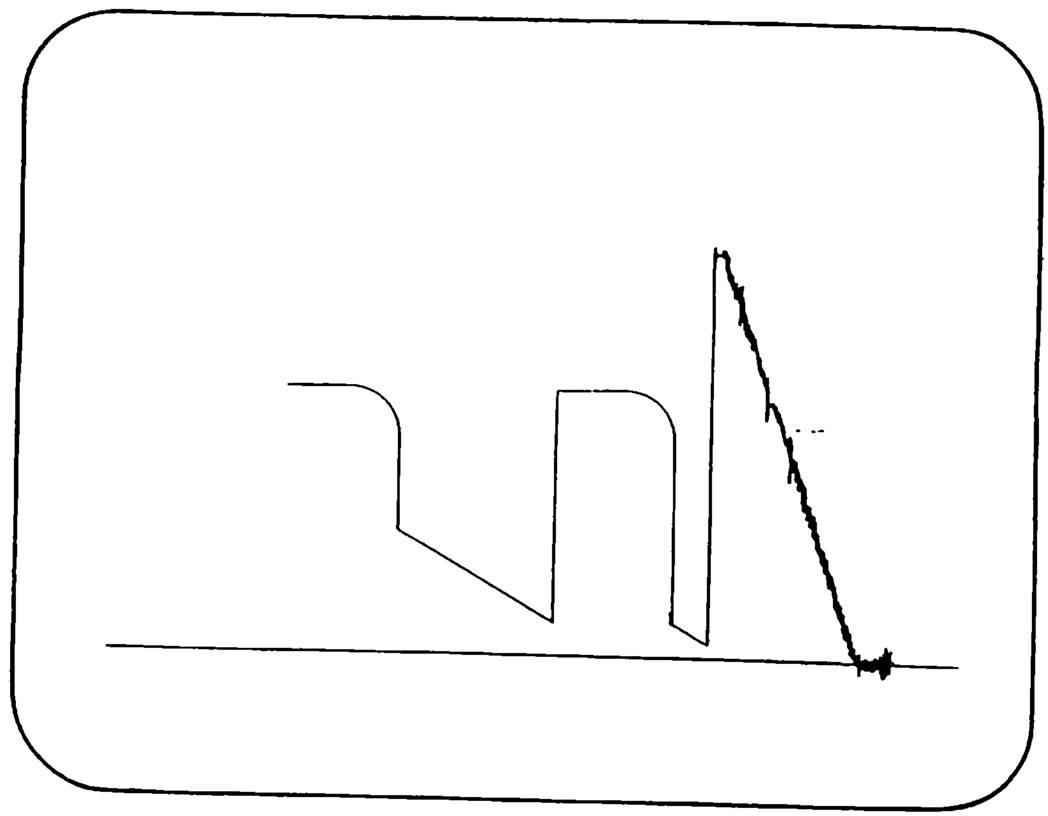
INITIAL SHUT-IN
Test inverval shut-in
Pressure build-up recorded.
Rate of build-up direct indication of permeability.



FINAL FLOW
Tool opened to allow flow into wellbore. Pressure increase indicating fluid entry into drill string.

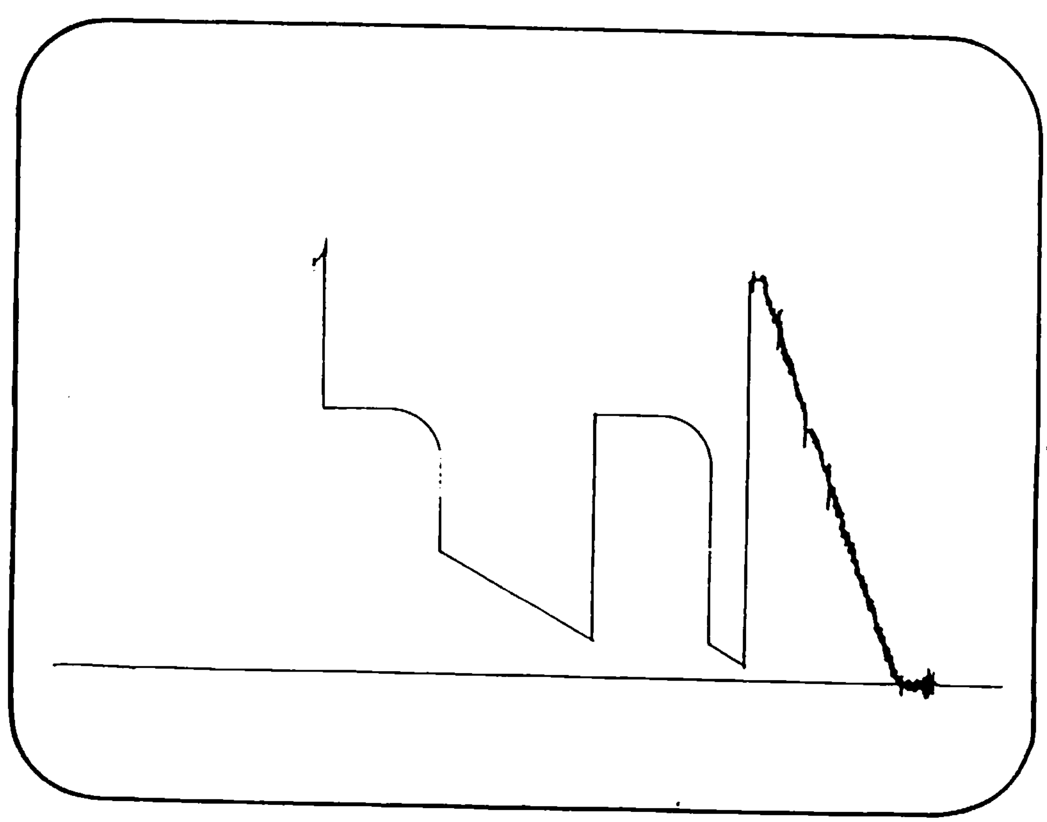
FINAL SHUT-IN

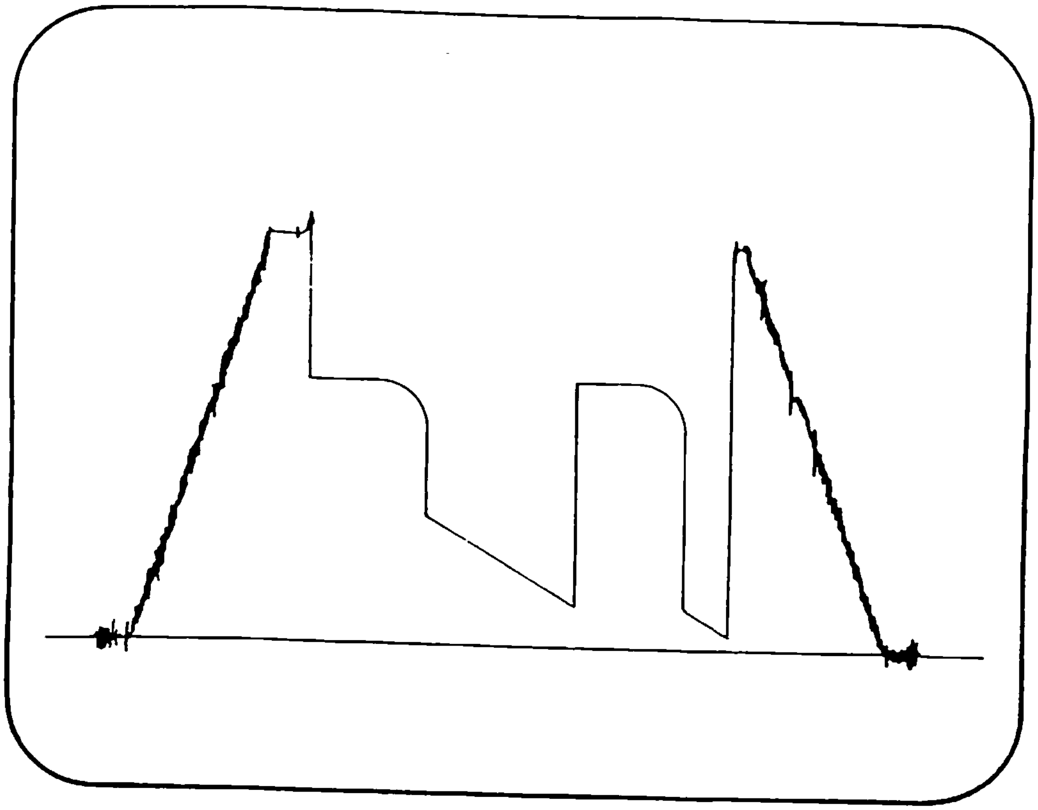
Tool shut-in to allow pressure build-up. The wellbore pressure approaching equilibrium with static reservoir pressure.



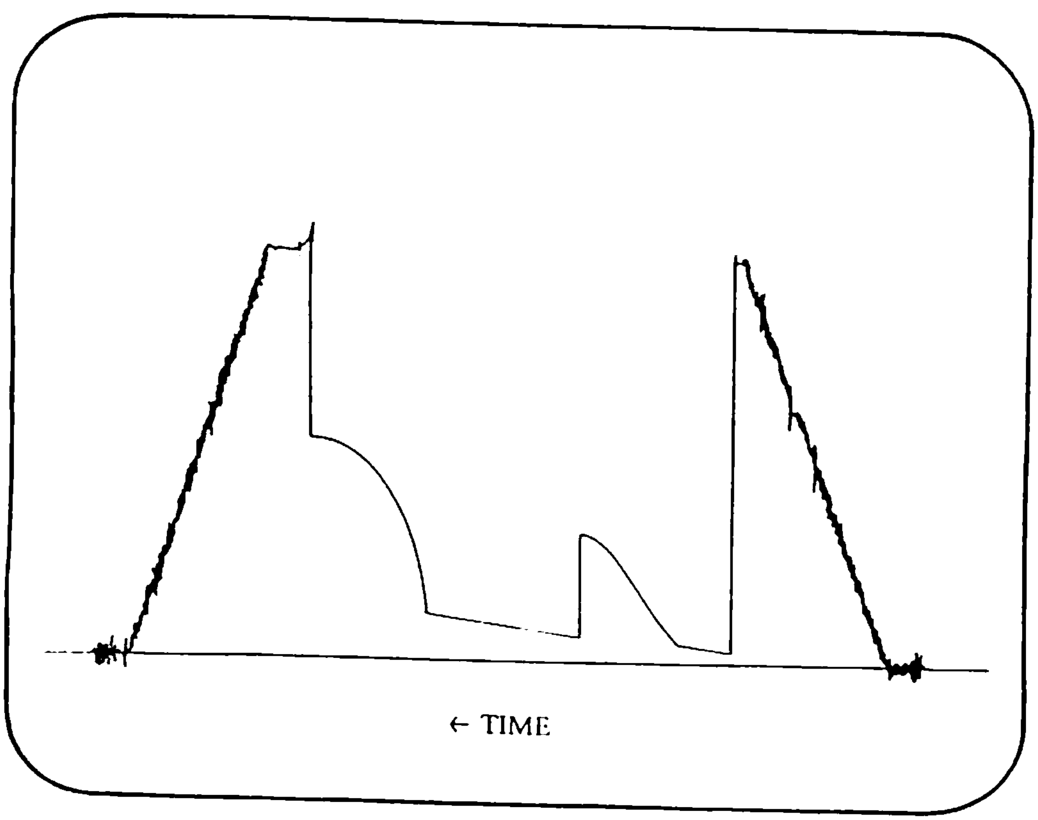
EQUALIZING

Ports opened to allow annular fluid communication to test zone.
Packers unseated.
Records final hydrostatic pressure.





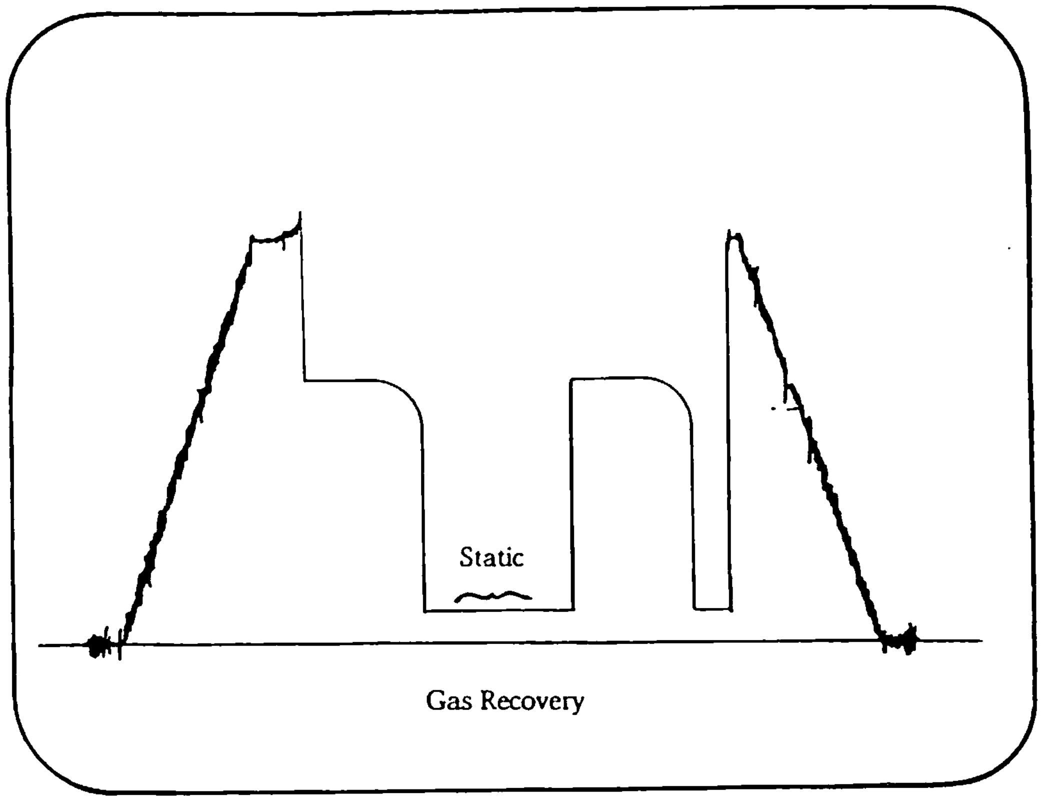
PULLING OUT OF HOLE
Records final hydrostatic and decline in weight of mud columr tool pulled out of hole.
At surface, fluid recovery, measured, charts examined.



← TIME
To determine direction of time o. DST charts find shut-ins. Shut-ins have build-up with respect to tin

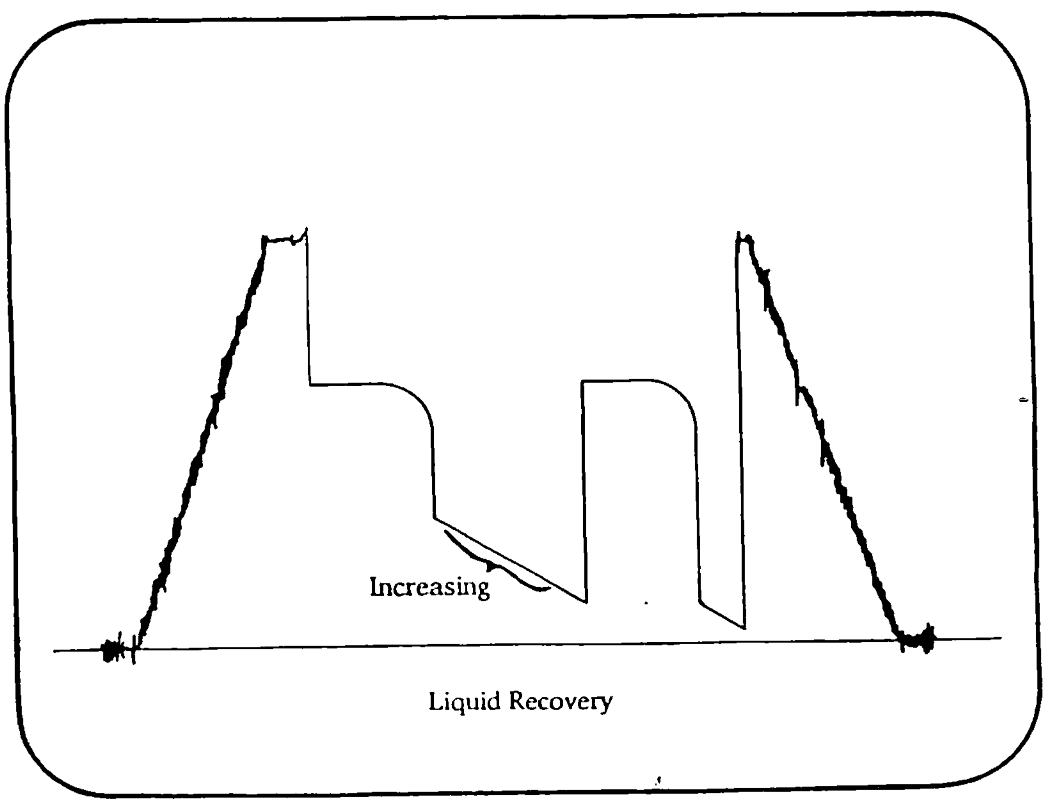
STATIC GAS RECOVERY

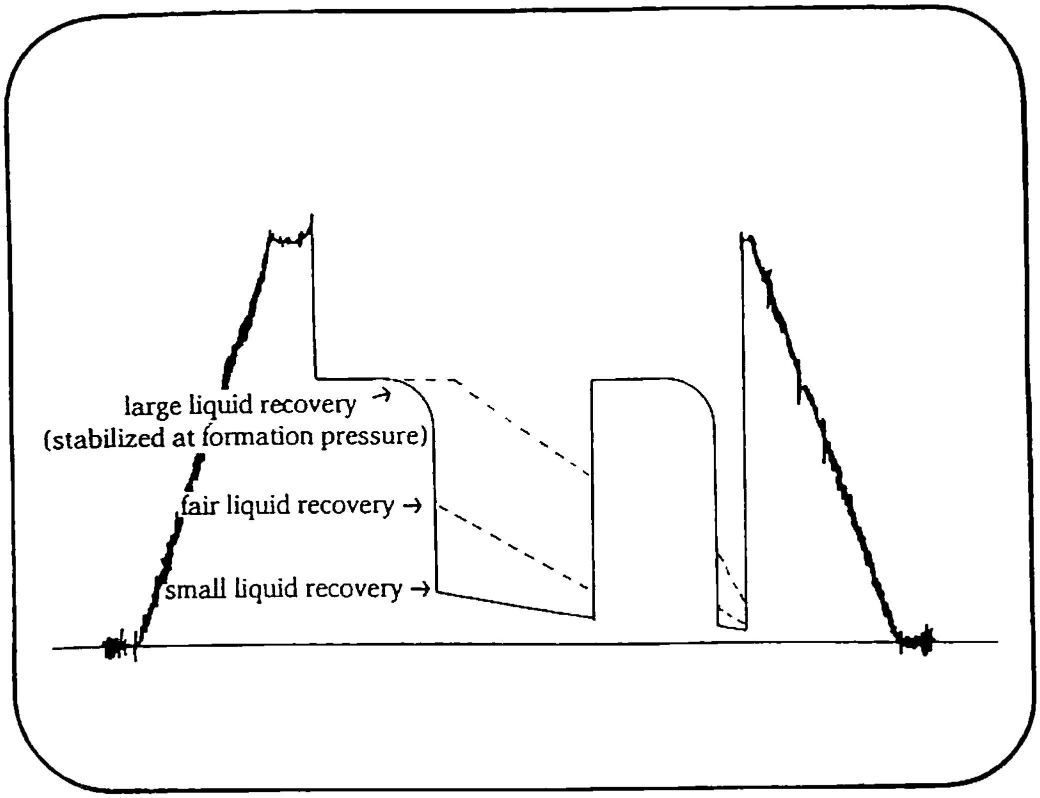
Flow periods allow the entry of liquids and gases into the drill pipe. A visual examination of the charts will tell you whether a test should have recorded gas or liquid. Rule of Thumb — static flow pressures indicate gas recovery.



INCREASING LIQUID RECOVERY FLOWS

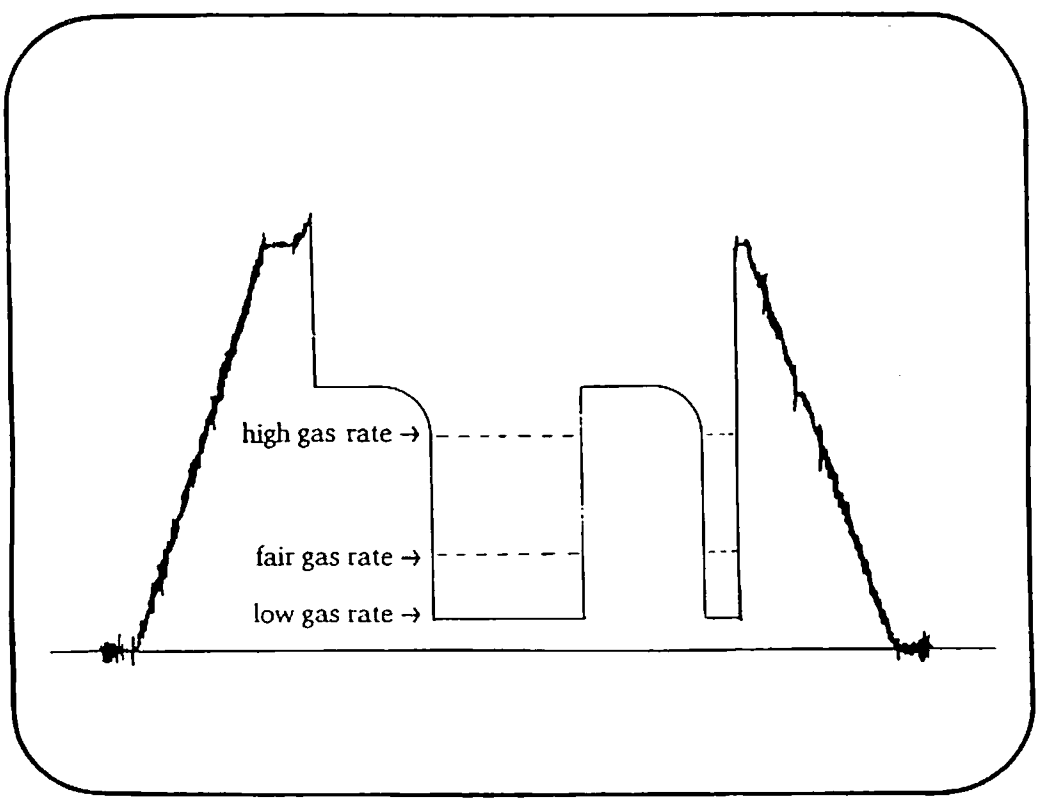
Rule of Thumb — increasing flow pressures indicates liquid recovery.





LIQUID RECOVERIES

For liquid, the greater the increase in flow pressures, the larger the column of liquid the reservoir pressure supports.

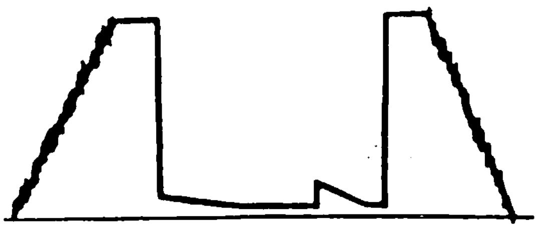


GAS RECOVERIES

For gas, the higher the static pressures, the larger the gas rate. The increase in pressure reflects back-pressure from the bottom choke.

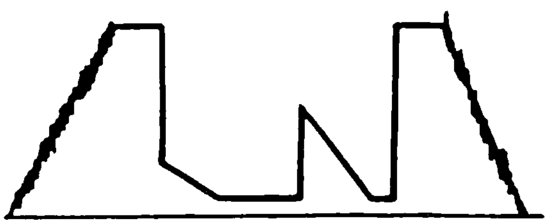
SHUT-INS

Shut-Ins record the pressure build-up immediately after a flow period. The rate of build-up is directly related to effective permeability. The following is a guide to estimating permeabilities based upon shut-in build-ups:



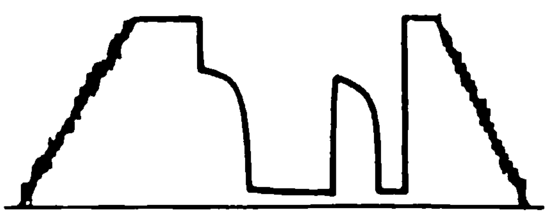
Liquid or Gas

NO BUILD-UP
Lack of permeability
usually only small
mud recovery.

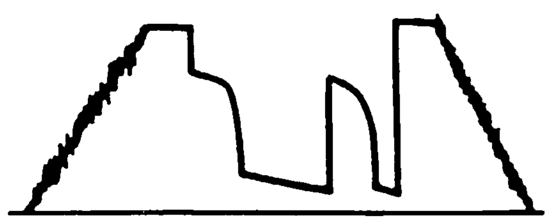


Liquid or Gas

SLOW BUILD-UP
Low permeability
Recovery < 100 feet liquid (often mud)

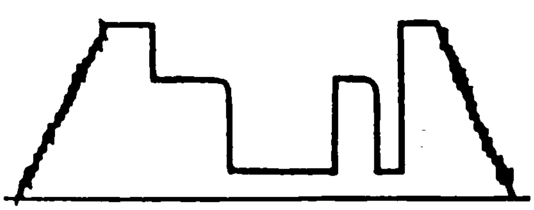


Gas

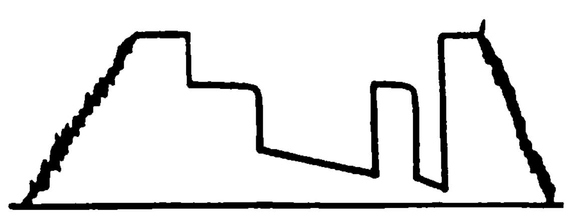


Liquid

MODERATE BUILD-UP
Rel. Low-Average Permeability-
Recovery-
Gas - 150 MCF
Liquid - 500 feet

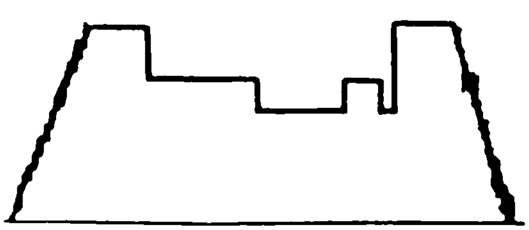


Gas

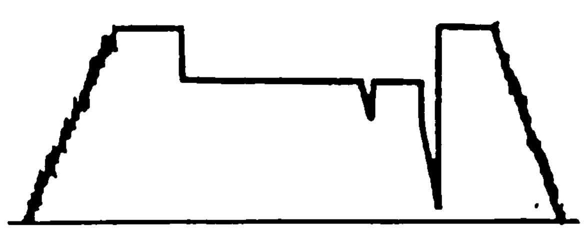


Liquid

RAPID BUILD-UP
High permeability
Stabilized shut-ins
Gas 500 MCF
Liquid 1000 feet

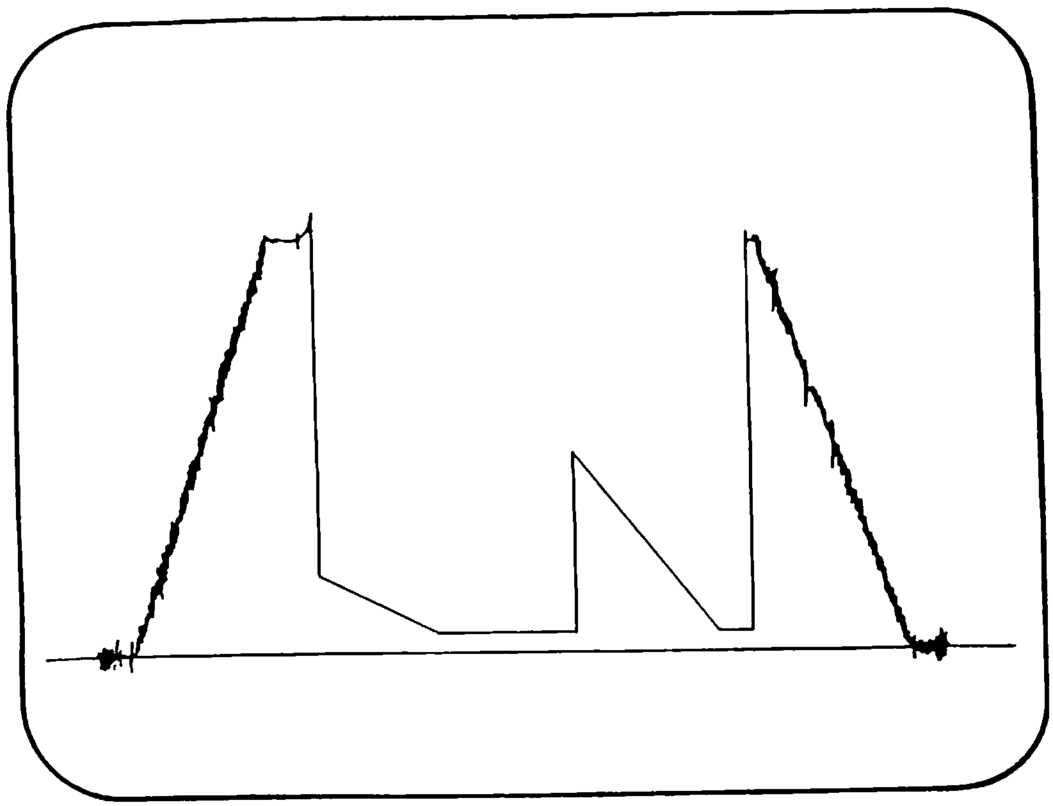


Gas

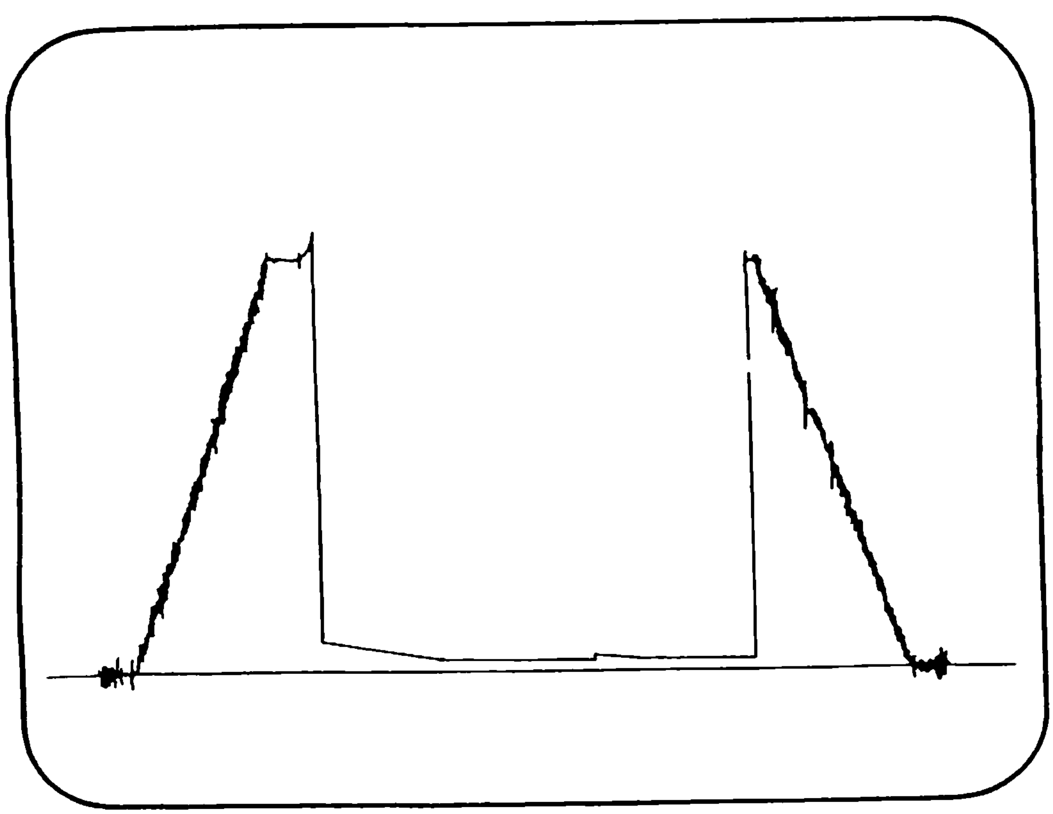


Liquid

IMMEDIATE STABILIZATION
Excellent permeability
Recovery-
Gas - 5,000 MCF
Liquid - 4,000 feet

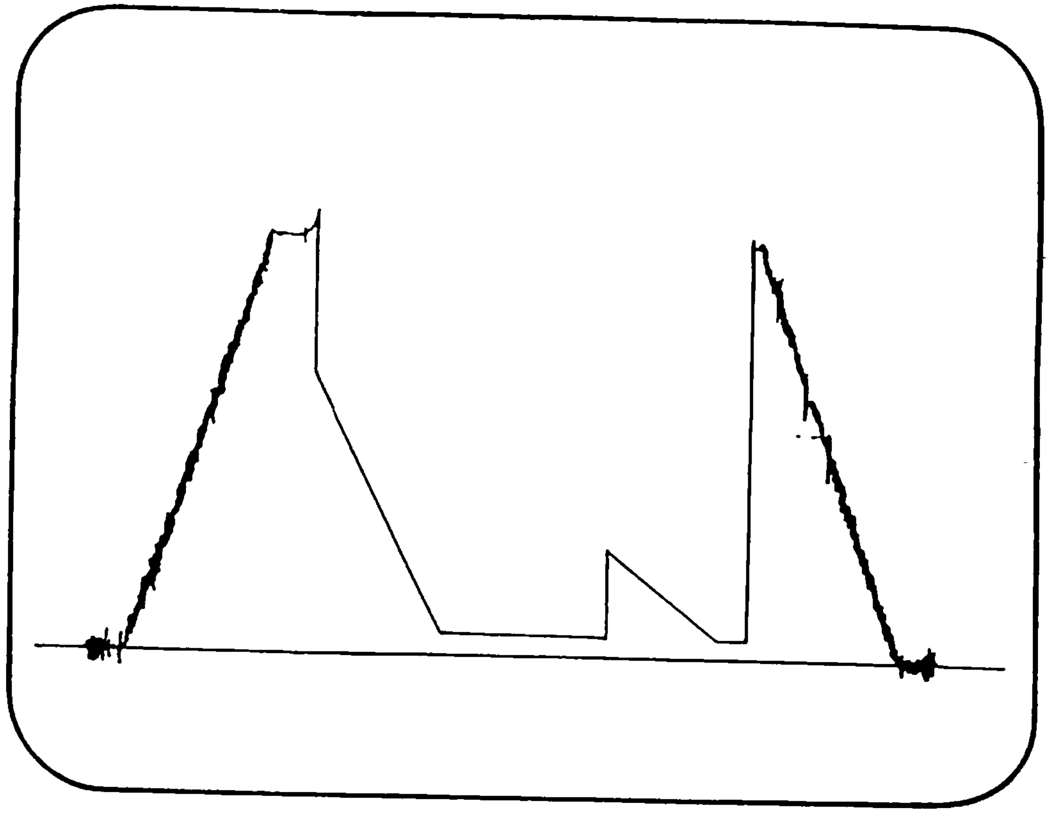


VERY LOW PERMEABILITY
Often low volume mud recovered
Permeability decreasing away from well-bore

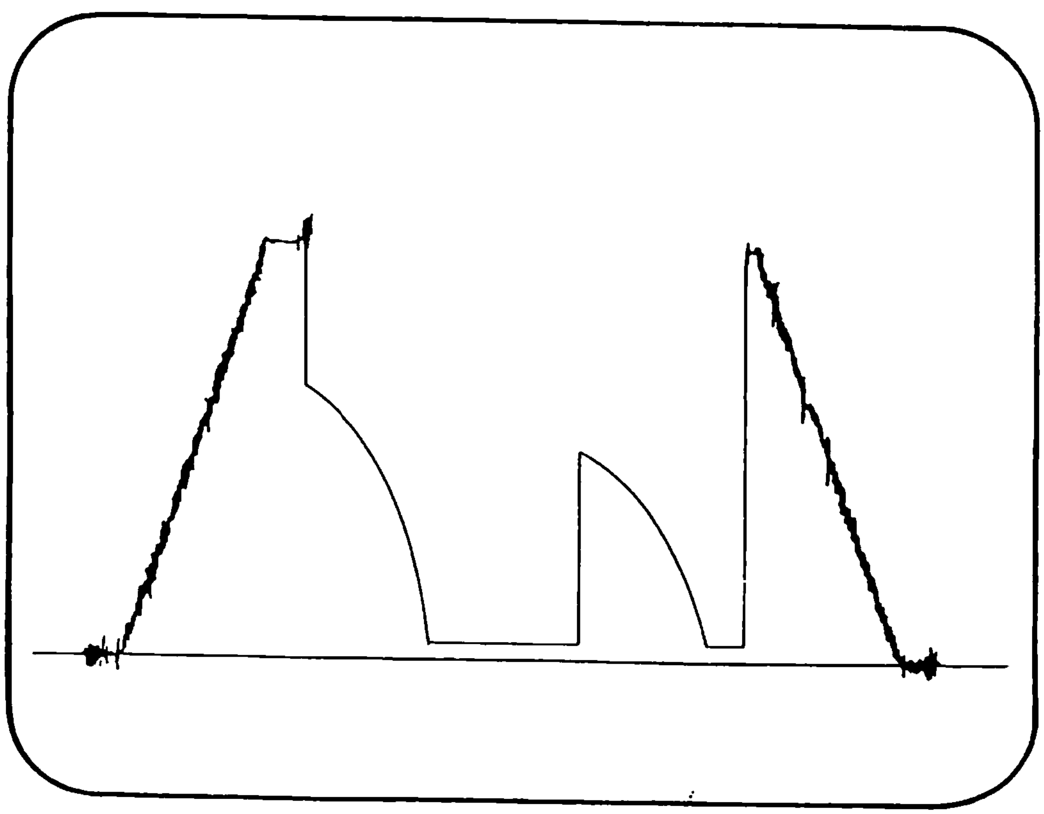


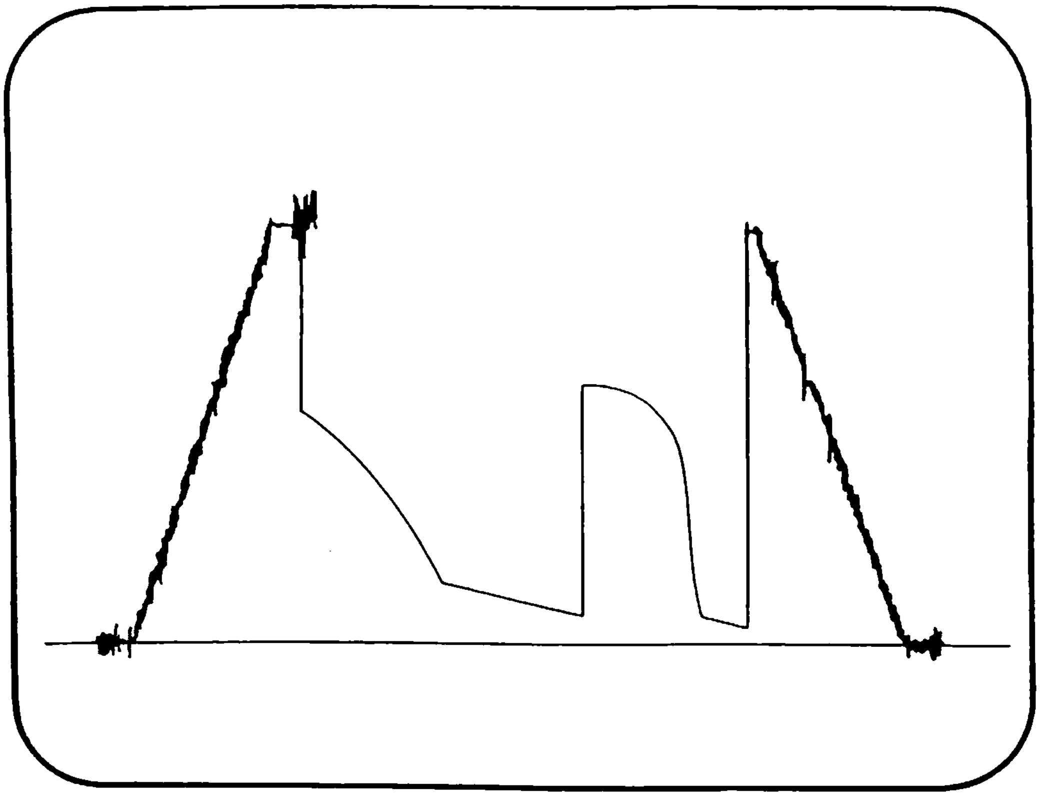
TIGHT
Very low recovery (5')
Very low permeability
Possibly shaly or no zone present in test interval

LOW PERMEABILITY
Low volume mud recovery or low volume gas
Permeability <u>increasing</u> away from well bore



FAIR PERMEABILITY
Fair reservoir pressures
If hydrocarbons recovered, test could prove productive with treatment

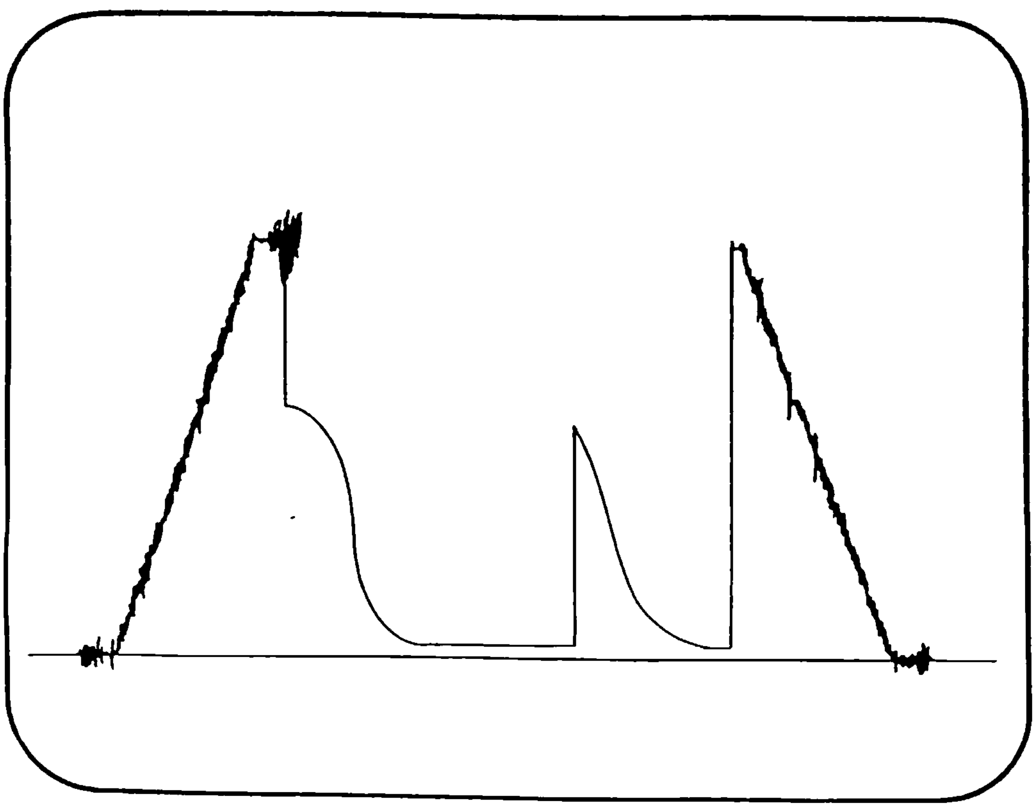




PRESSURE EXTRAPOLATION NEEDED

No depletion

Although F.B.H.P. reads several hundred pounds lower than I.B.H.P., in majority of the cases the F.B.H.P. will extrapolate back to I.B.H.P.



"S" CURVE

Curve developed by fluid compression below test valve

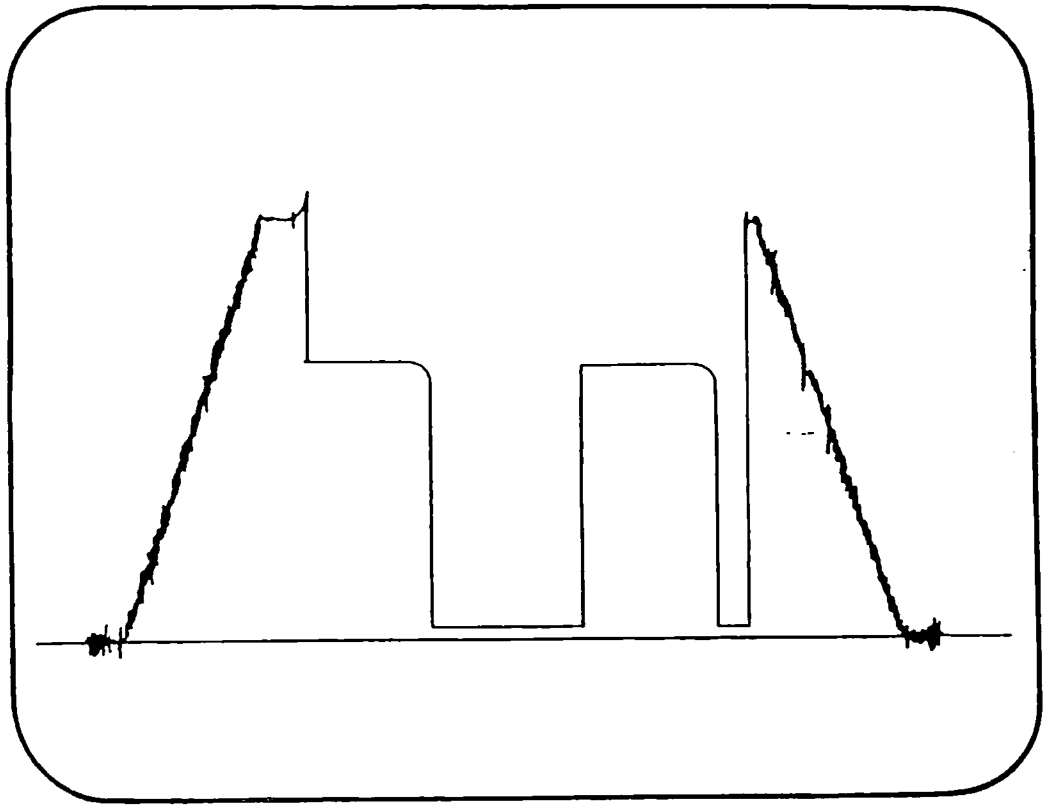
Gas may go back into solution during an increase in pressure

Extra long test interval (60' or over)

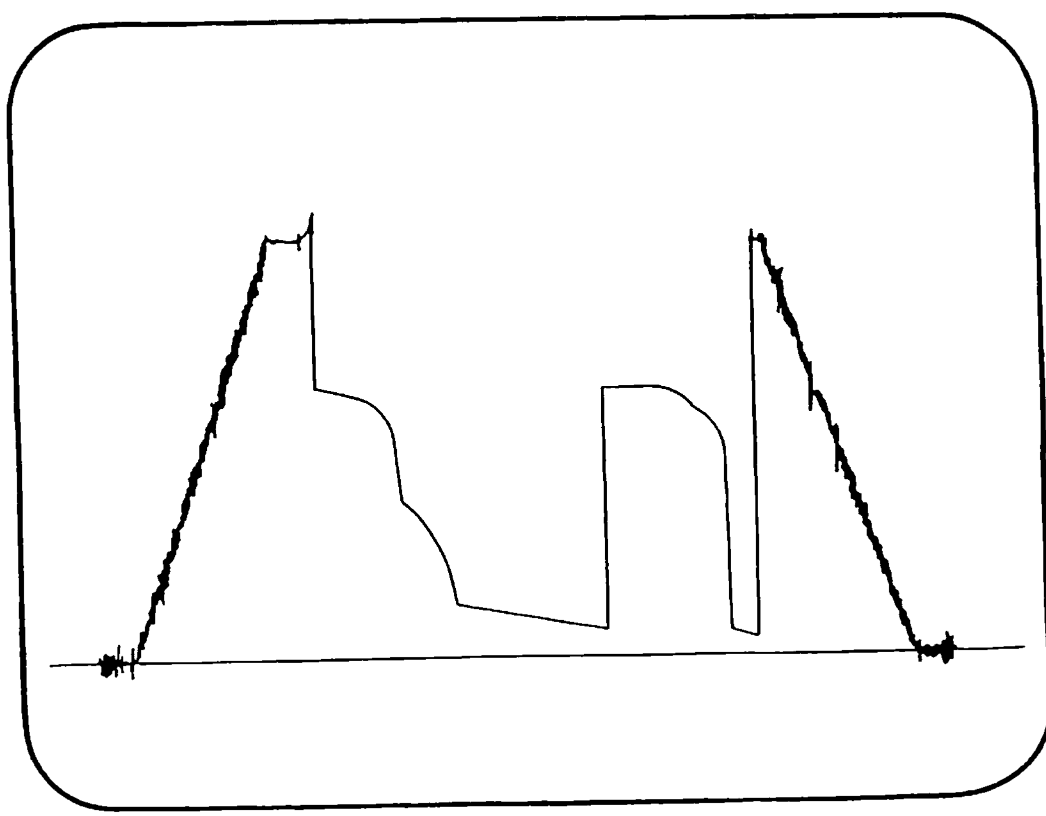
Low permeability

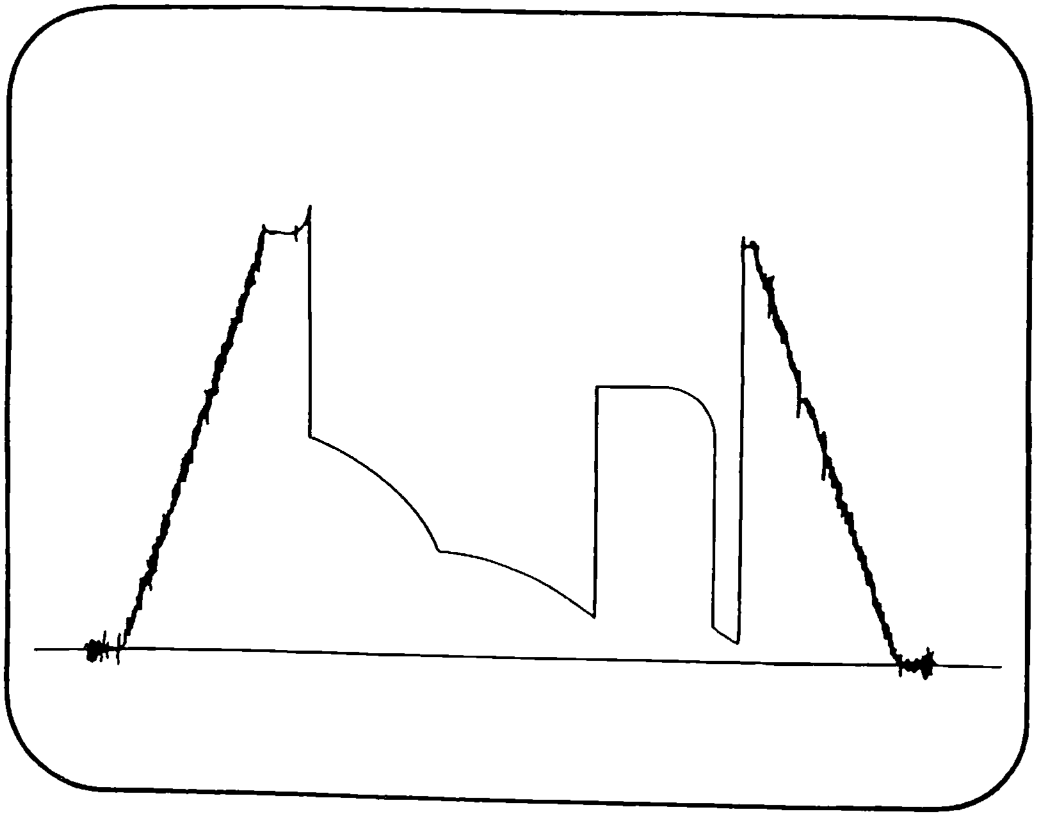
Low volume of Oil and Gas may be recovered

WELL BORE DAMAGE
Good permeability
Rapidly building B.H.P.'s
Low fluid recovery
Low gas volumes

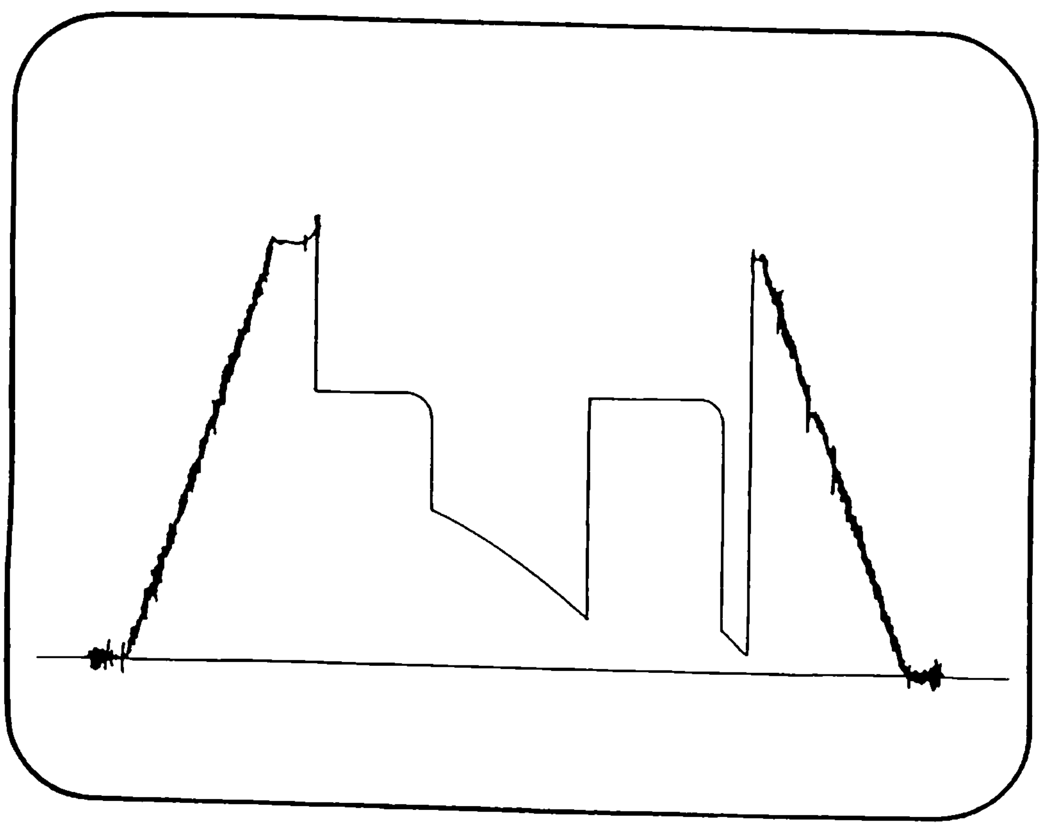


TWO ZONE EFFECT
Two entirely different producing zones exposed in a test interval
One zone has higher reservoir pressure or better permeability
Fair permeability



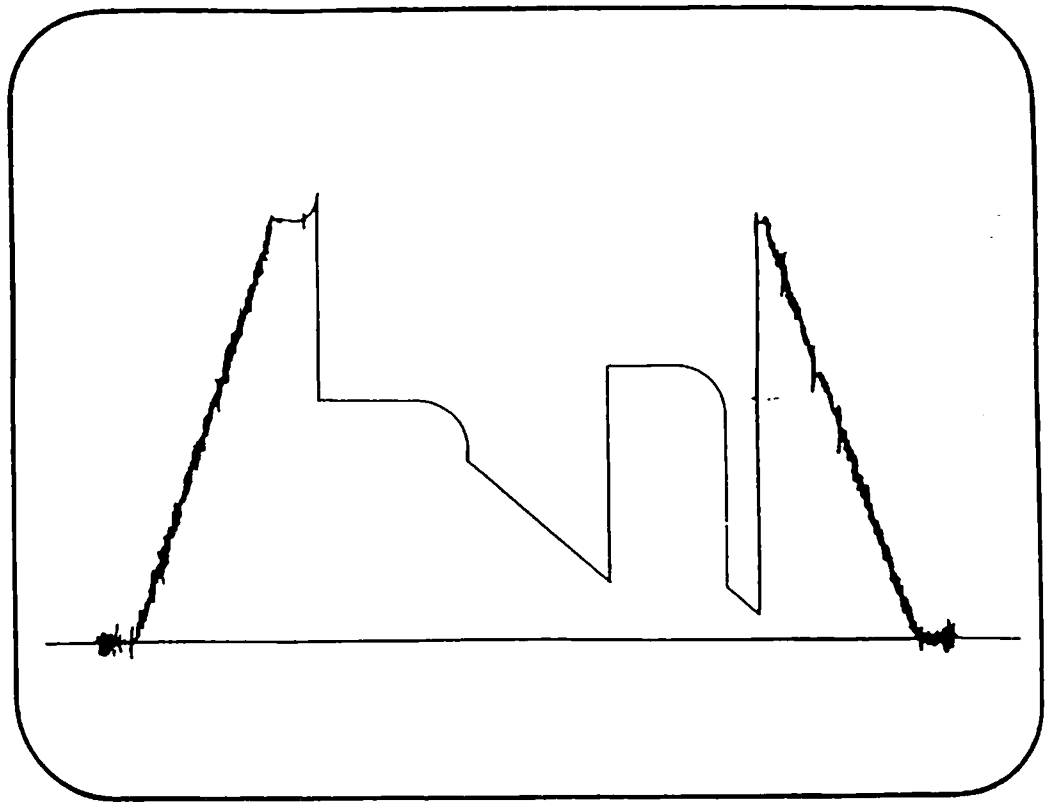


BARRIER WITHIN RADIUS OF INVESTIGATION
Chart needs further analysis
(Pressure plots, etc.)
Good permeability

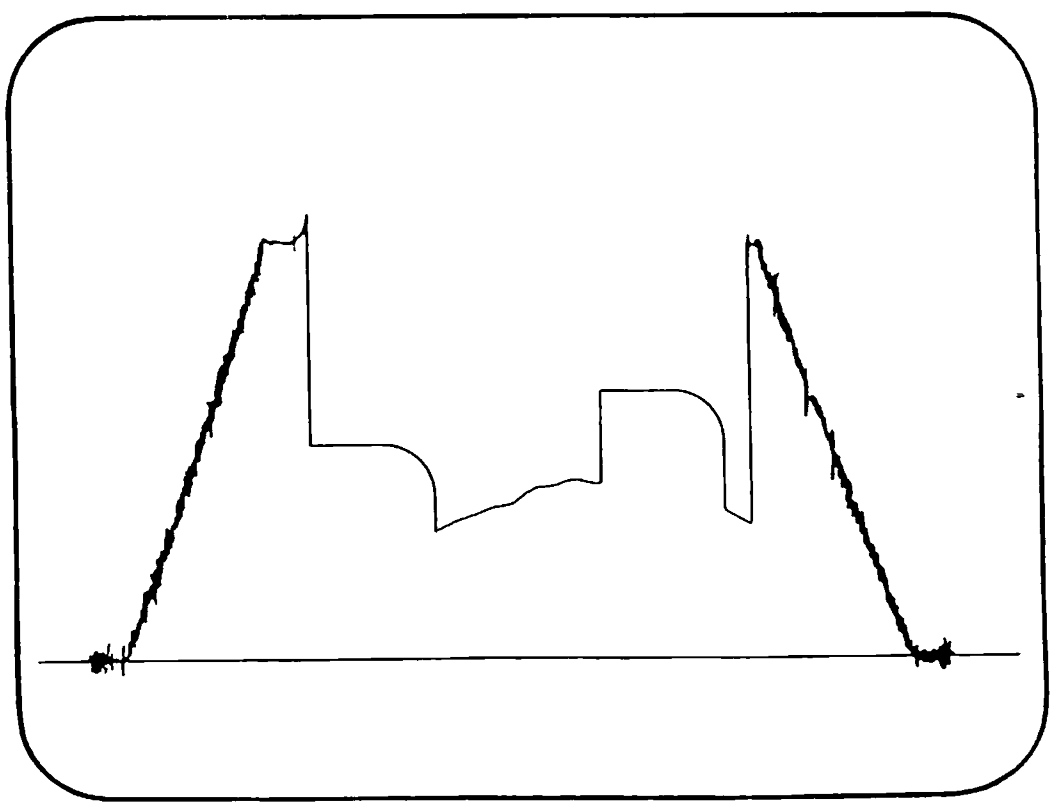


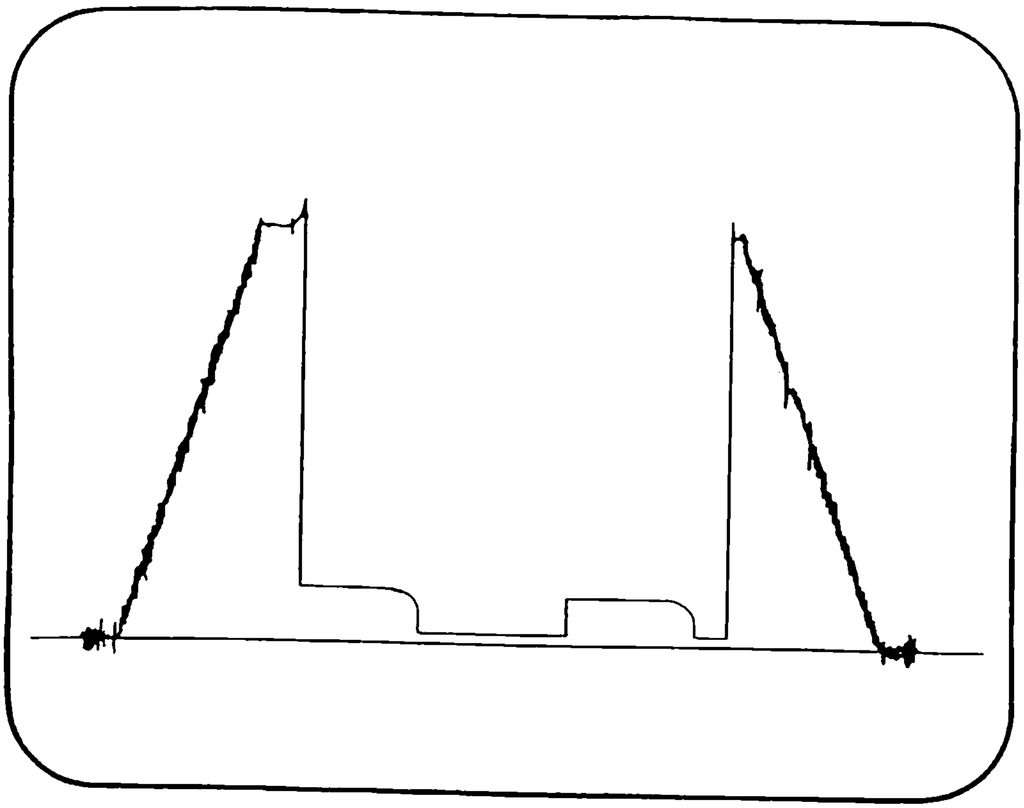
NO RESERVOIR DEPLETION
Excellent permeability
Liquid test
High liquid recovery

RESERVOIR DEPLETING
Indicated by drop in FBHP
Liquid test
Excellent permeability
Both B.H.P. reached static pressure normally observed on high volume liquid tests



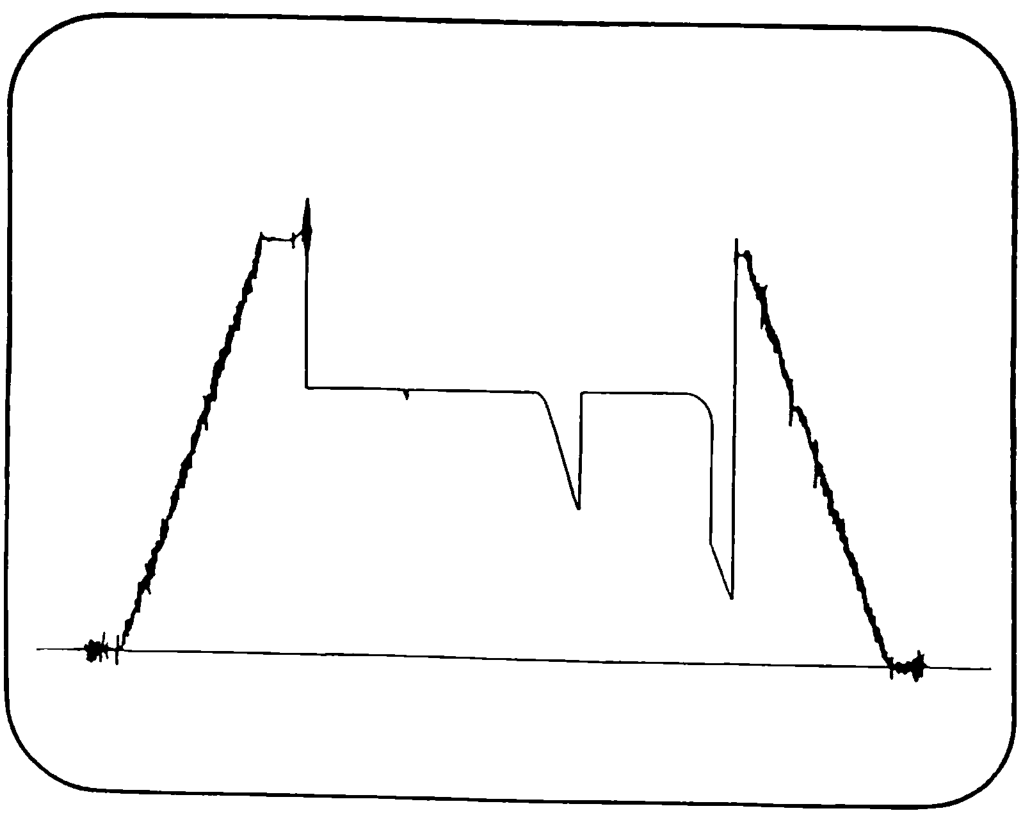
RESERVOIR DEPLETING
Indicated by drop in F.B.H.P.
Gas test
Excellent permeability
Both B.H.P. reached static pressure
Normally observed on high gas volume tests





RESERVOIR HAS BEEN DEPLETED

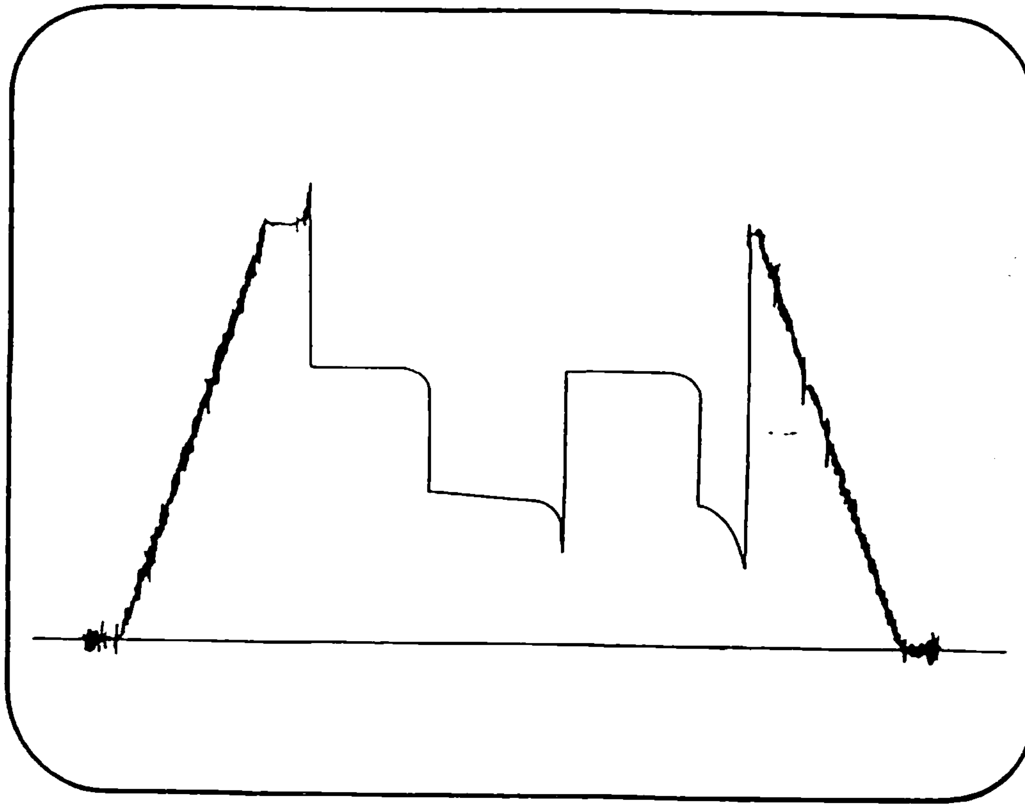
Zone has already been produced
80% of virgin B.H.P. has been depleted
Good permeability



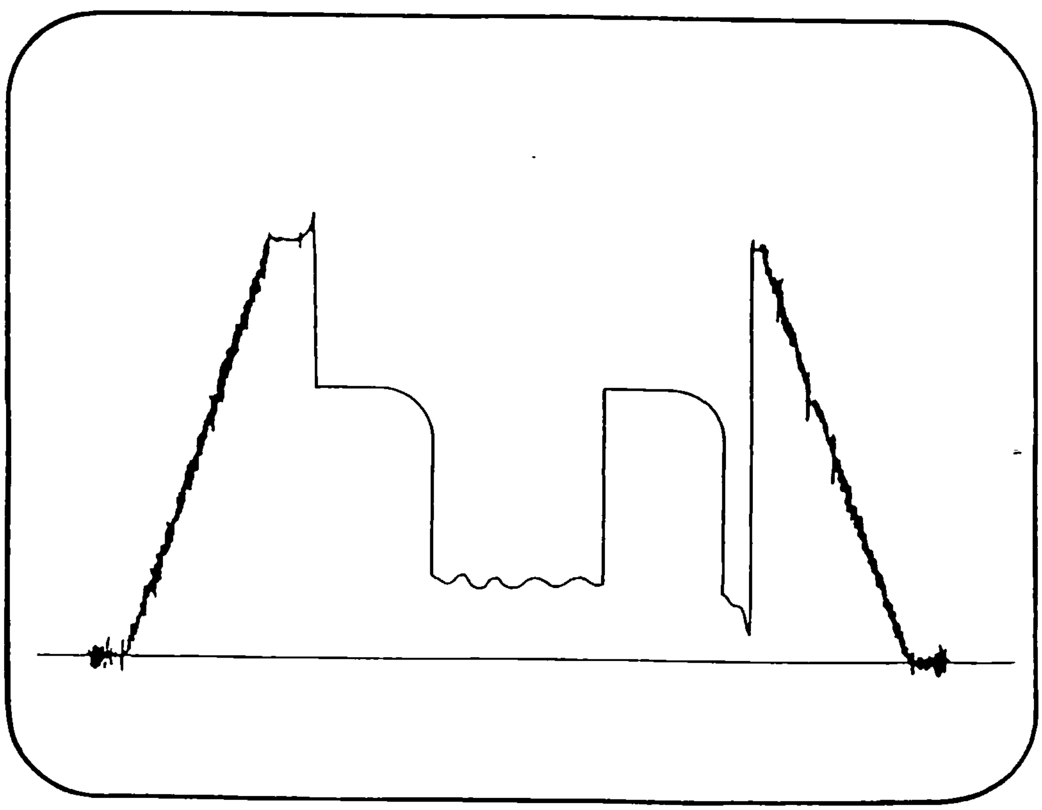
STABILIZED FLOW (STATIC)

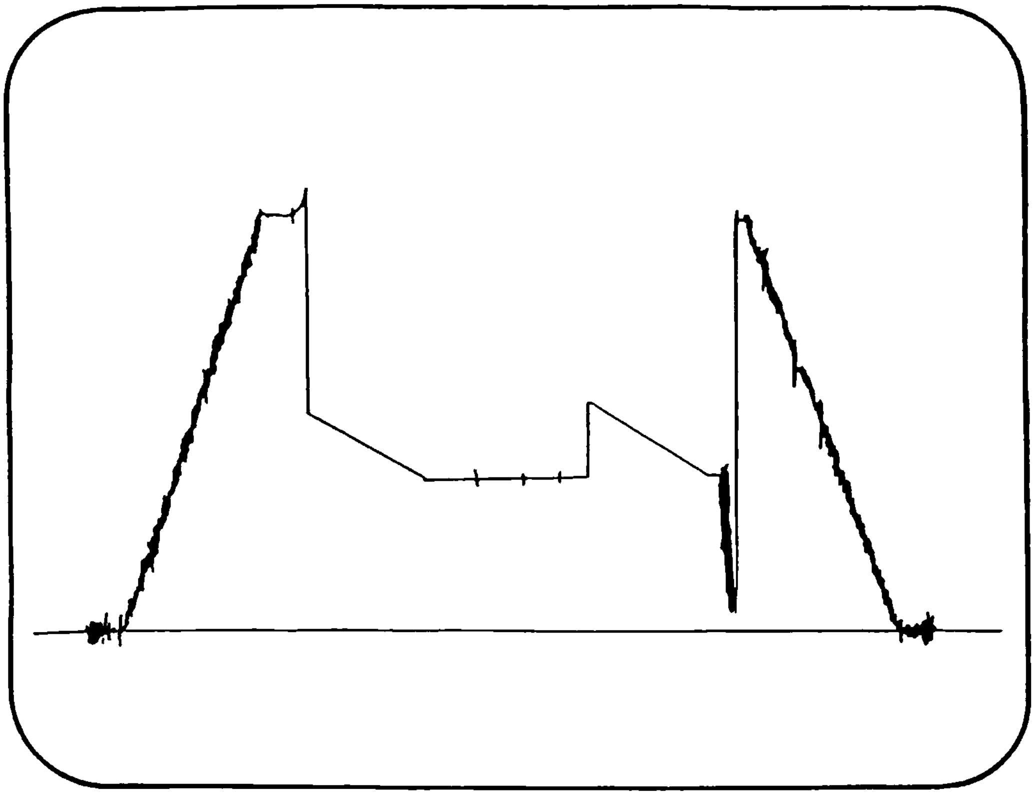
Flow pressure increasing to static reservoir pressure during F.F.P.
Flow pressure cannot go higher than static Res. Pressure
Excellent permeability
High fluid recovery

HIGH GAS FLOW
Excellent permeability
Gas volumes should be increasing at surface
Low or no fluid recovery

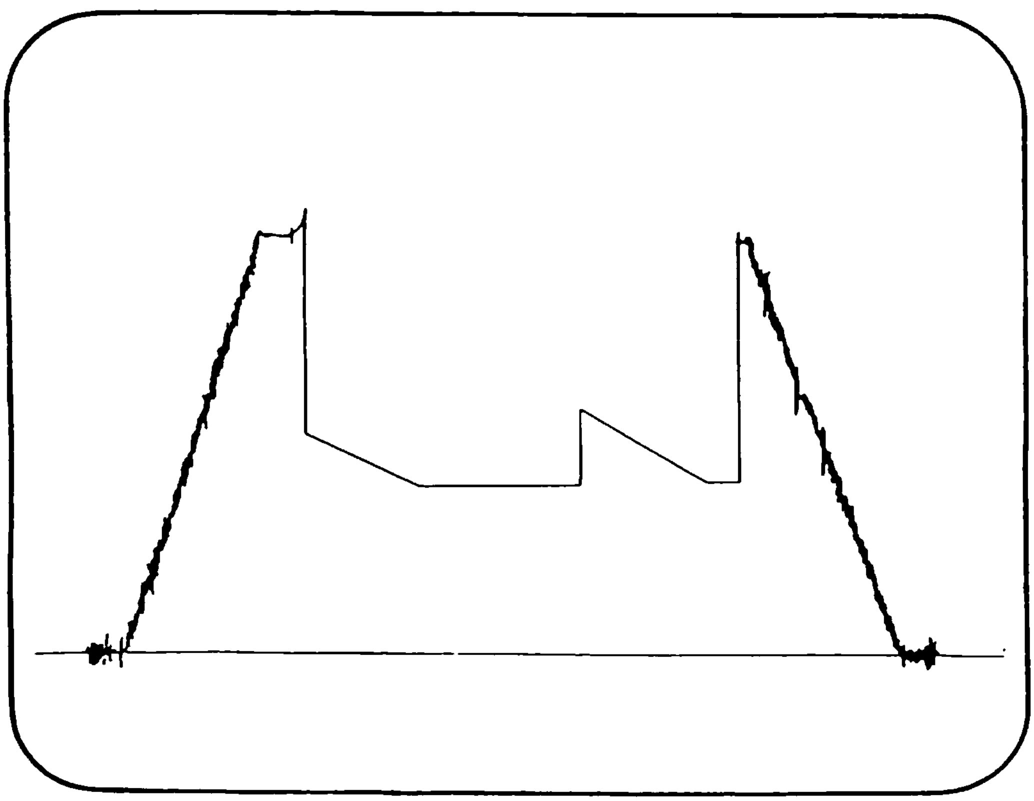


WELL FLOWING FLUIDS AND GAS AT SURFACE
Gas carries fluid to surface
Fluid builds up in drill pipe then gas unloads fluid at surface
Good permeability - fair fluid recovery





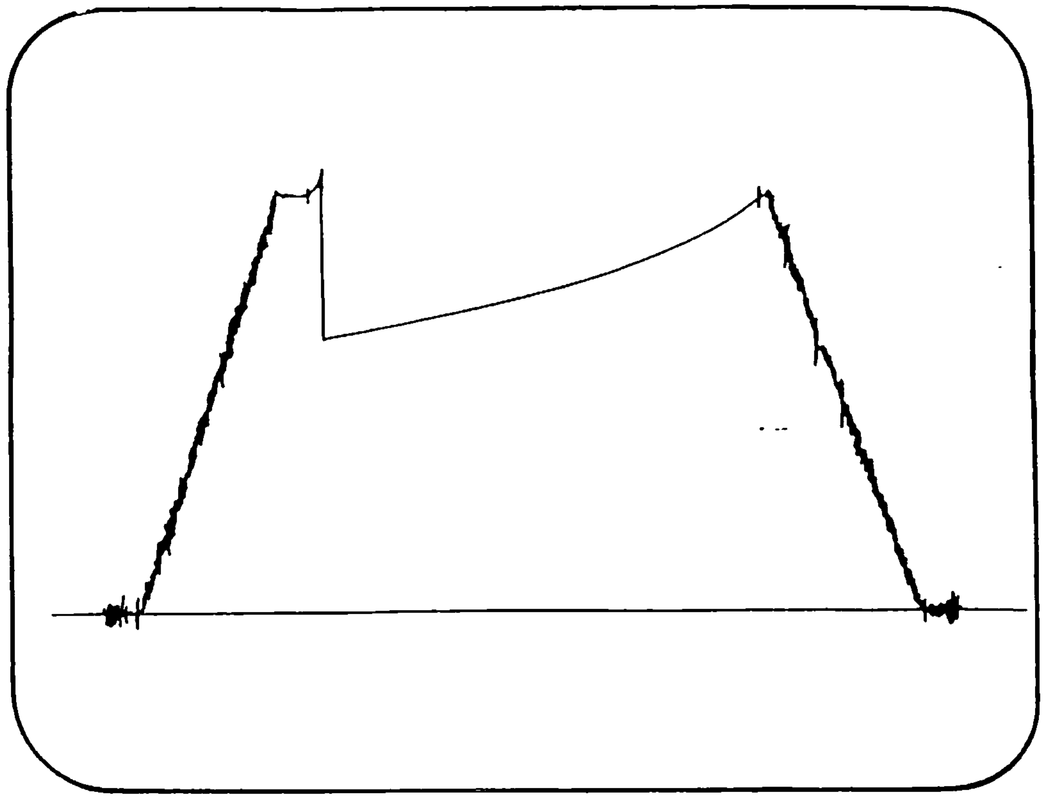
LOST CIRCULATION ZONE
Normally fractured zone
Produces fluid (often drlg mud) very quickly then stabilizes
High fluid recoveries



WATER CUSHIONS
Water cushions can be used in deep tests. Their purpose is to reduce the pressure differential across the packers when the tool is initially opened. When a water cushion is used, the charts displa a time delay on the trip in the hole while the cushion is being added and a flow pressure increase equivalent to the weight of the cushion.

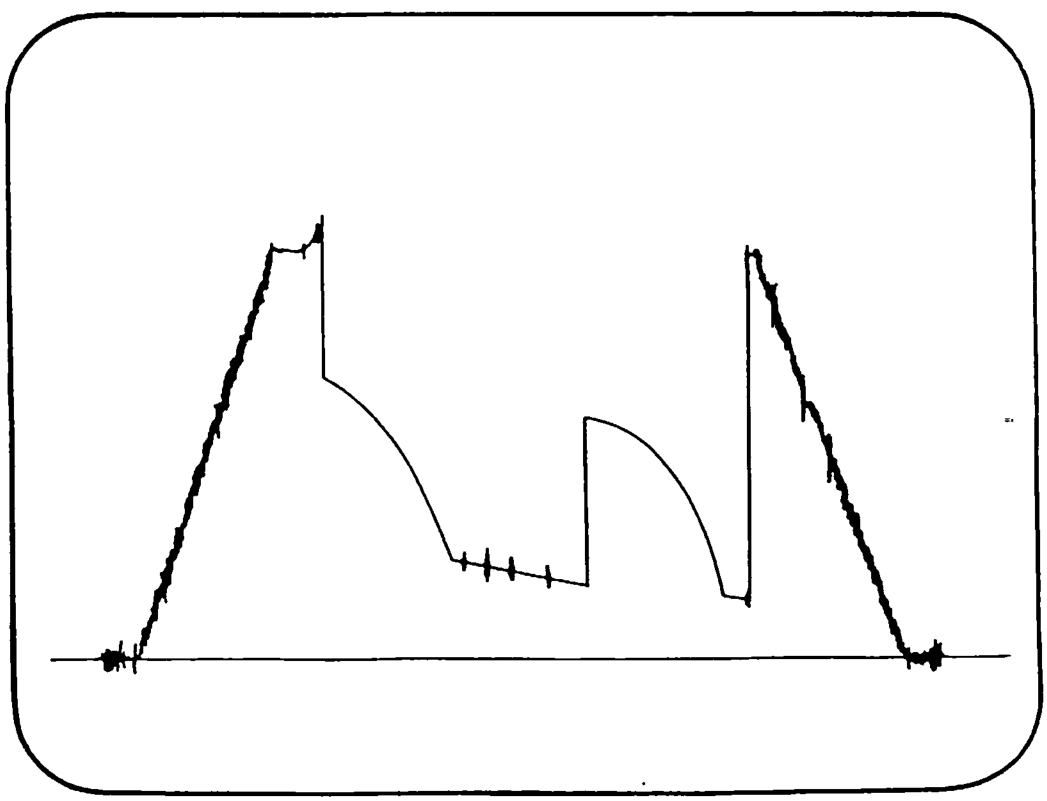
BELOW STRADDLE CHART
(BELOW BOTTOM PACKER)

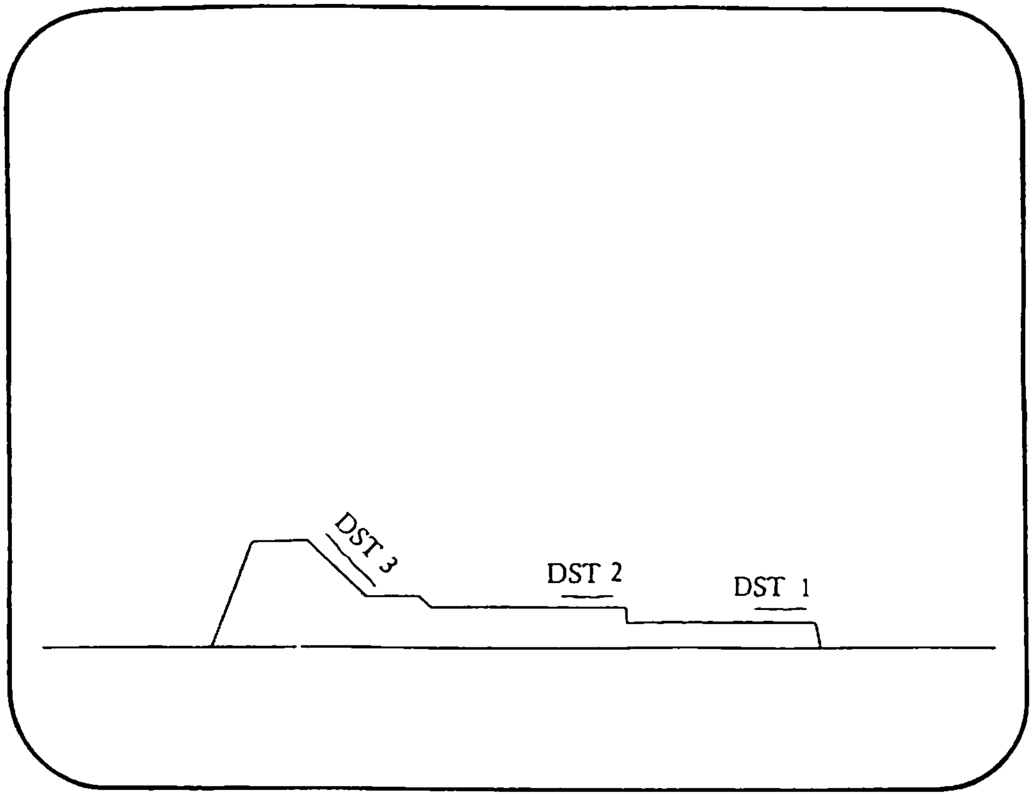
Bottom packer held, test successful
Hydrostatic pressure is trapped below bottom packer
Trapped hydrostatic pressure bleeds to lowest formation pressure exposed below bottom packer
This chart should not compare to chart run in test interval (between packers)



BELOW STRADDLE CHART
(BELOW BOTTOM PACKER)

Bottom packer DID NOT hold, test unsuccessful
Chart is very comparable to chart run in test interval (between packers)
Fluids, gas etc. can communicate around bottom packer

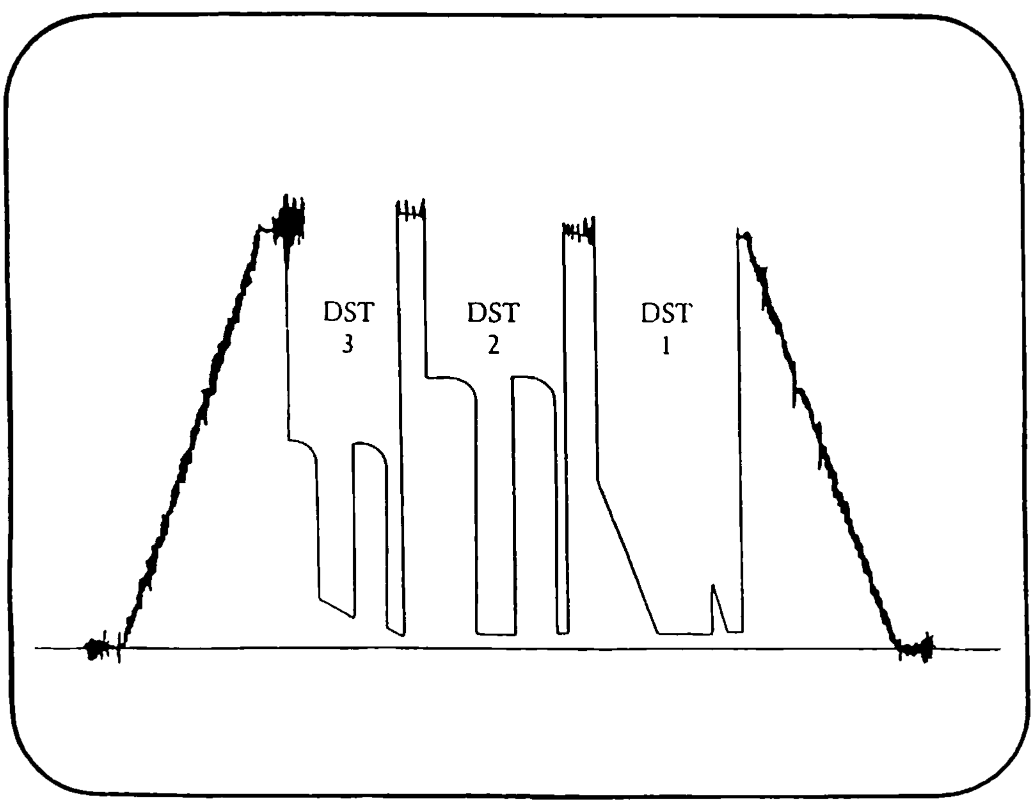




ABOVE SHUT-IN TOOL RECORDERS

Inside recorders can be placed above the shut-in tool to record flowing pressures and measure hydrostatic head of fluid recoveries. They are run on all closed-chamber DST's and are useful on multiple tests.

Example is of above multiple test: (DST 3 recovers large liquid column while DST's 1 and 2 recover very little)



MULTIPLE TESTS

Multiple tests can be run on the same trip in the hole.
Individual tests can be determined by examination of hydrostatics an identification by service company.

Conditions That Cause Drill Stem Test Failures and How They May Be Overcome By Proper Planning

There are a number of things necessary for the success of a drill stem test. Most failures of drill stem testing are due to:

(1) No Packer Seat - Set packer in sand, lime or dolomites (Never in Shale). If possible run a caliper log.

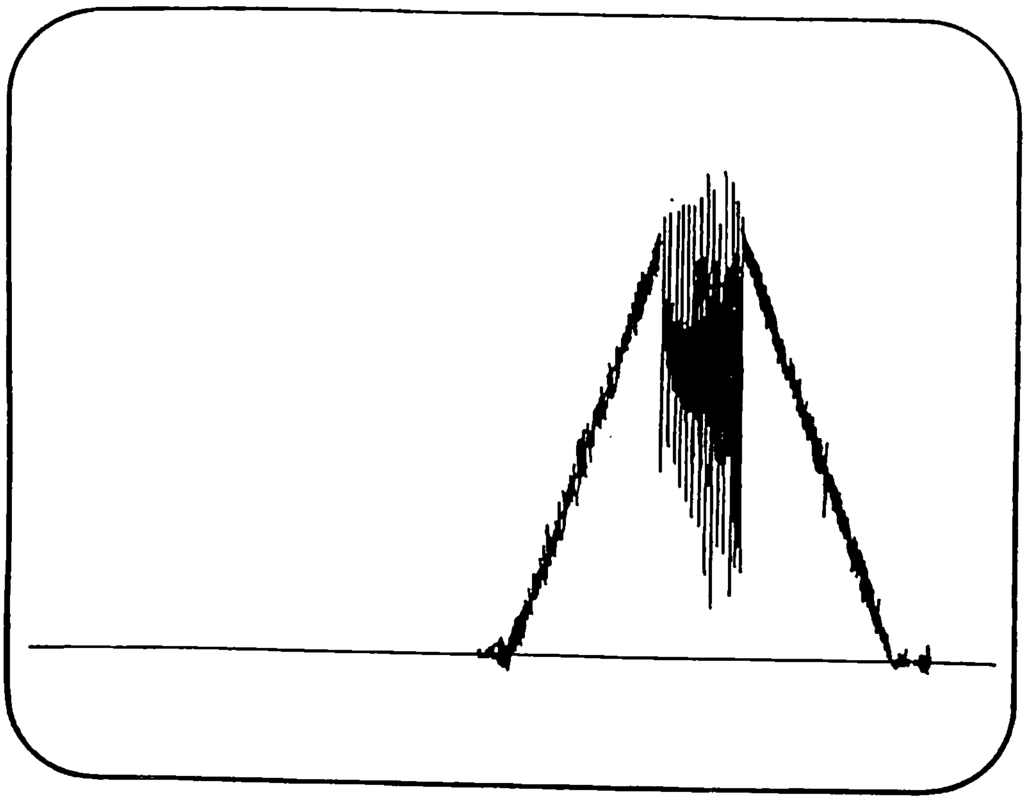
(2) Cavings in hole - this is generally because the mud is not in good enough condition to remove cuttings from well bore or not enough circulation of mud prior to coming out of hole for test.

(3) Selecting proper size element - to insure proper sealing of packing element there should not be over 1 inch clearance and in some cases even less. (This is the total diameter clearance.)

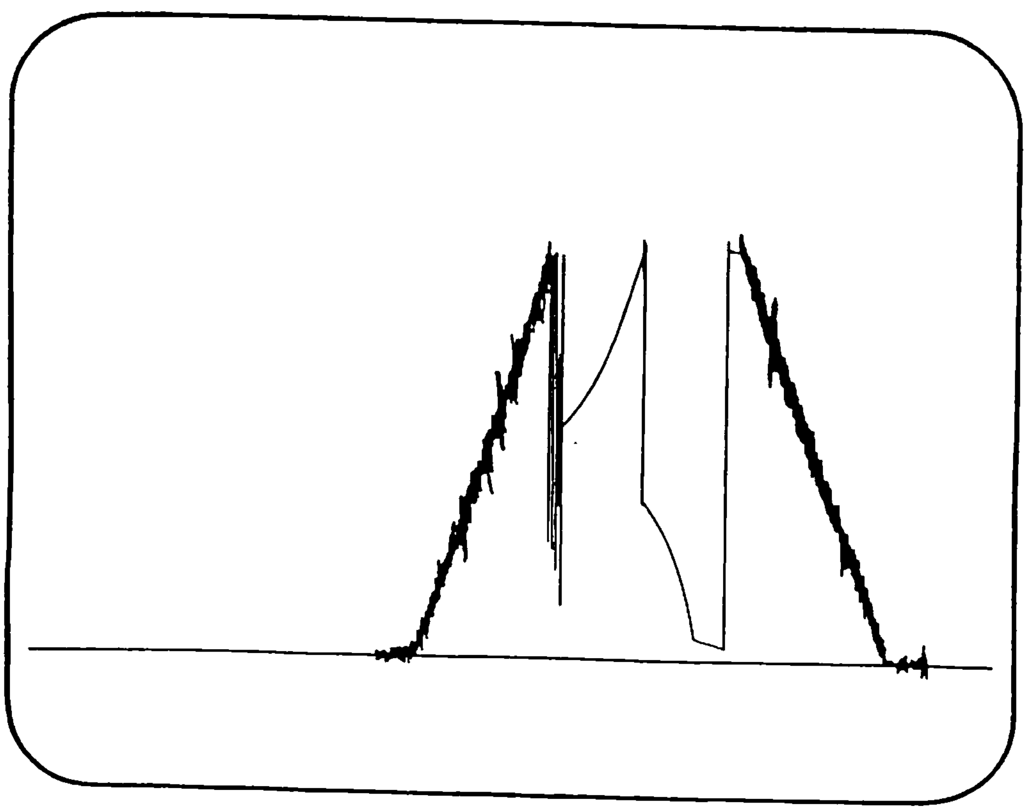
(4) Running in hole - care must be taken when going in hole to prevent breaking down of weak formations. With a small clearance between packer element and wall of hole a pressure is built up under the packer and can cause loss circulation. "Go slow."

(5) Packer leakage - in unconsolidated or weak formations the differential pressure may be high enough to cause packer leakage when test valve is opened. Keep the differential pressure at a minimum by the use of water or gas cushions. 5000 PSI is recommended maximum for differential. Also two packers run in tandem might prevent leakage.

(5a) Packer leakage due to high permeability or vertical fractures which are most common in limestone and dolomites. Run two or possibly three packers in tandem and keep differential pressure at minimum across packer.



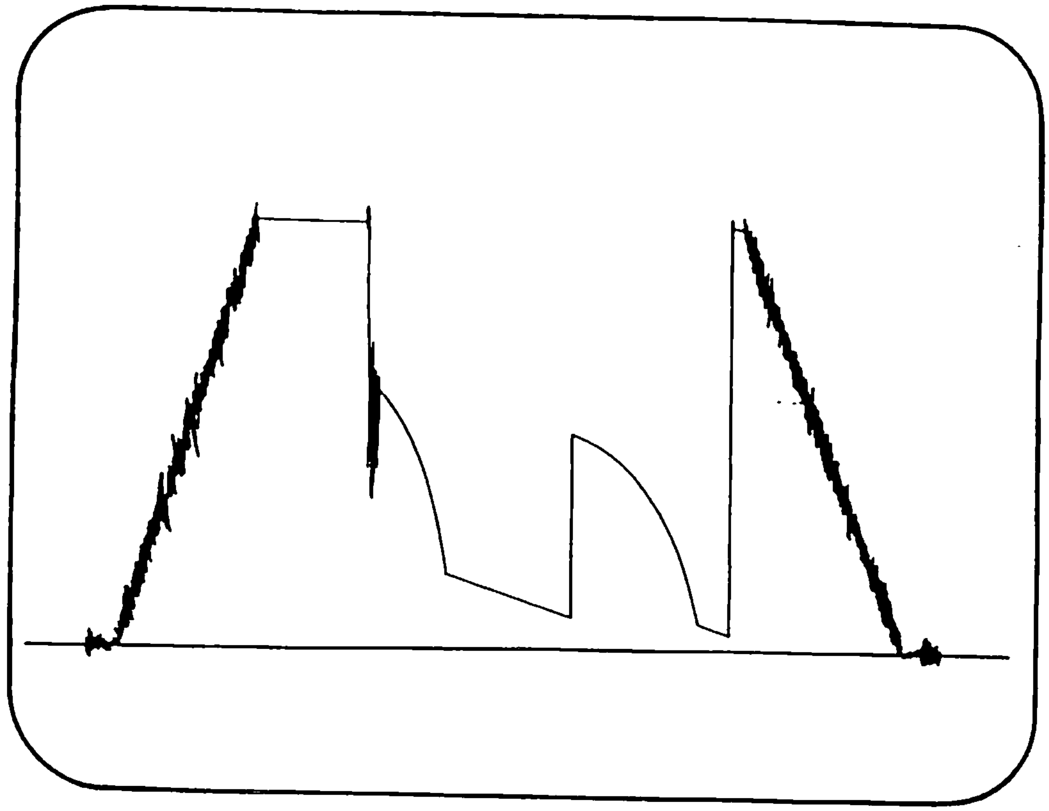
PACKER FAILURE
Hole out of gauge
Vertical fractures
Large recovery of drilling mud



PACKER FAILED DURING INITIAL SHUT IN
Hole out of gauge
Vertical fractures
No conclusive pressures
No conclusive recovery
Drilling mud mixed with recovery

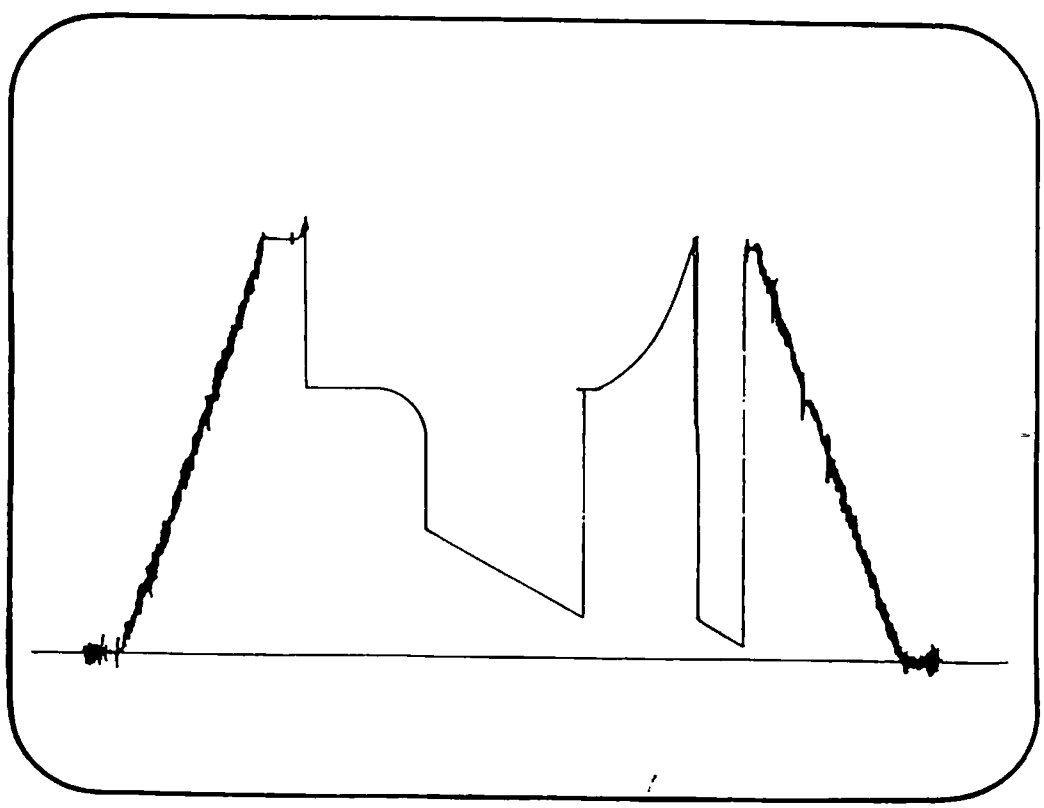
PACKER FAILED DURING
FINAL SHUT IN

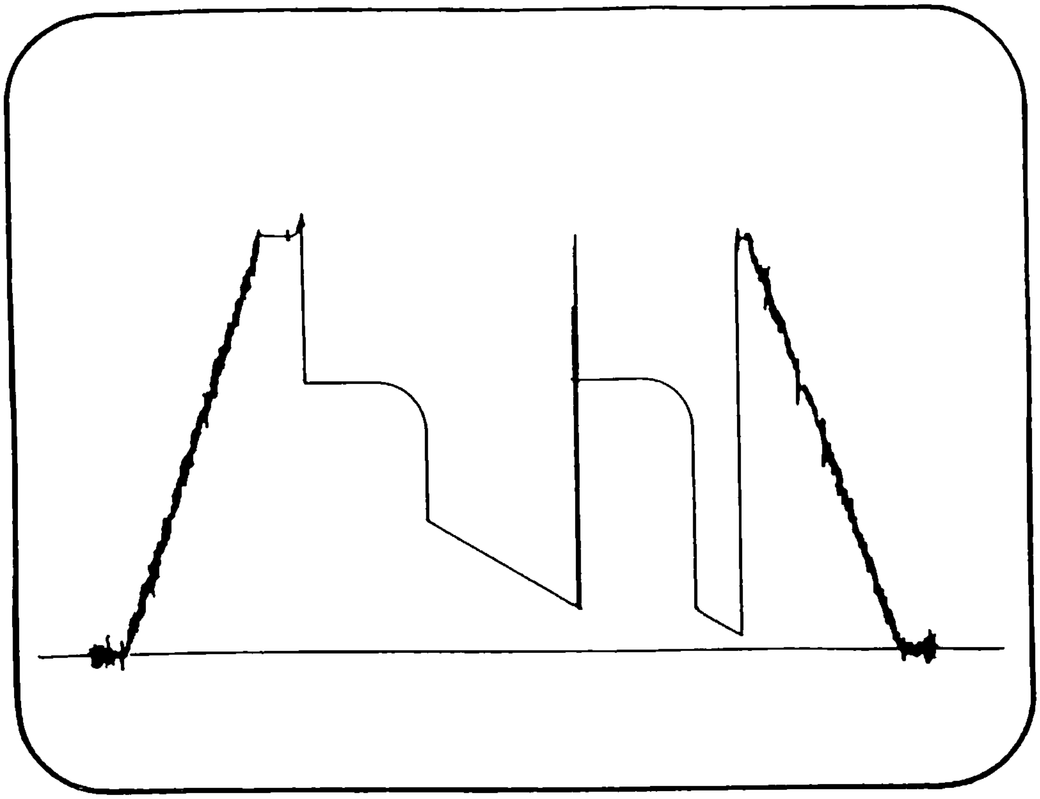
Hole slightly out of gauge
Vertical fractures
I.S.I. pressure is accurate
Drilling mud mixed with recovery



TEST TOOL BY-PASSED TO
HYDROSTATIC

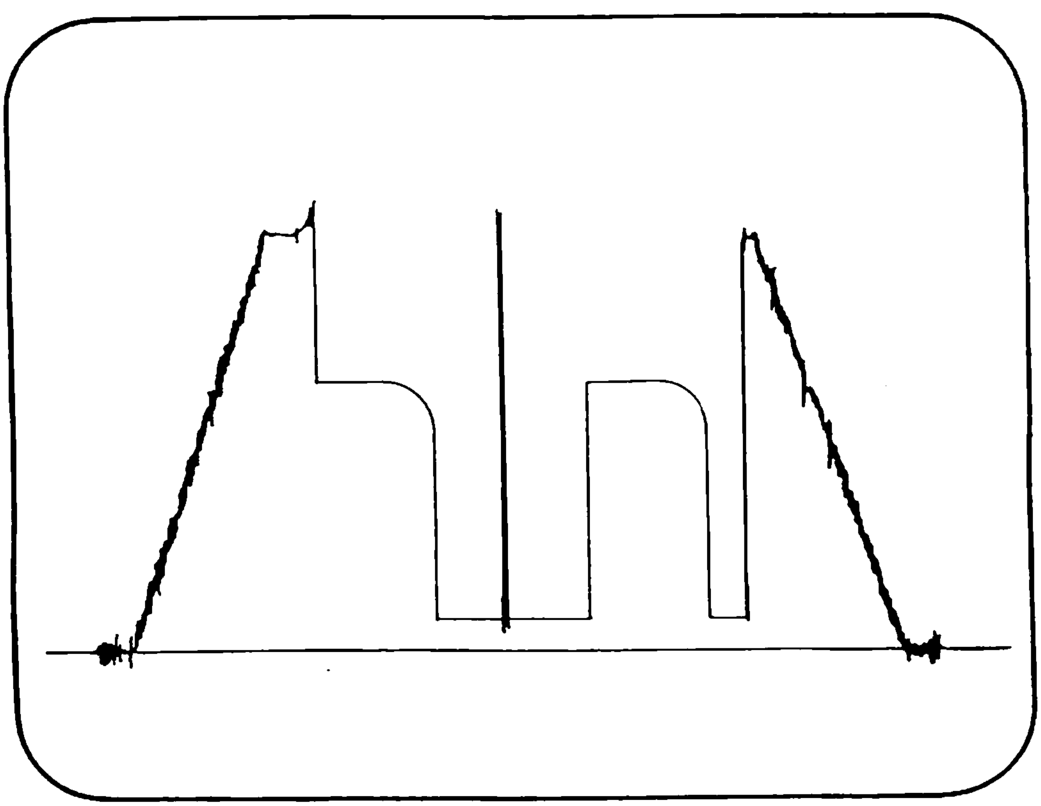
Accidently by-passed during I.S.I.
Pipe picked up or rotated to
extreme
I.S.I. false
Often no effect on recovery





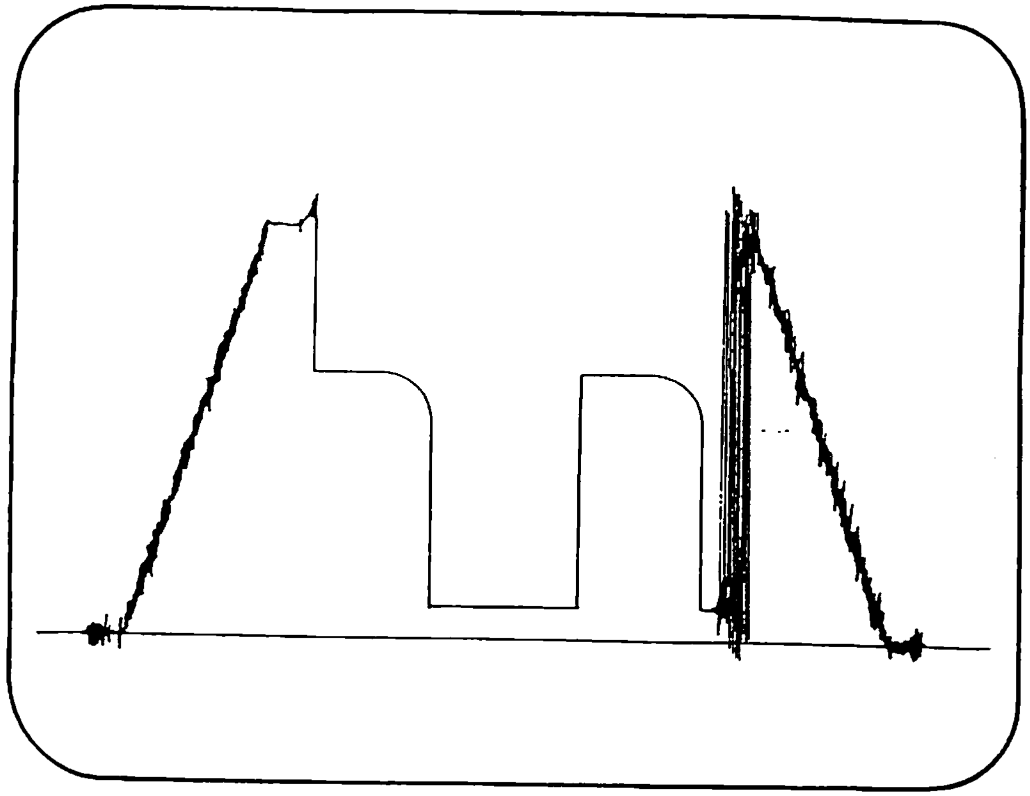
TEST TOOL BY-PASSED

Tool by-passed accidently at star
of F.F.P.
Drill pipe picked up or rotated t
extreme
No effect or slight effect on
recovery

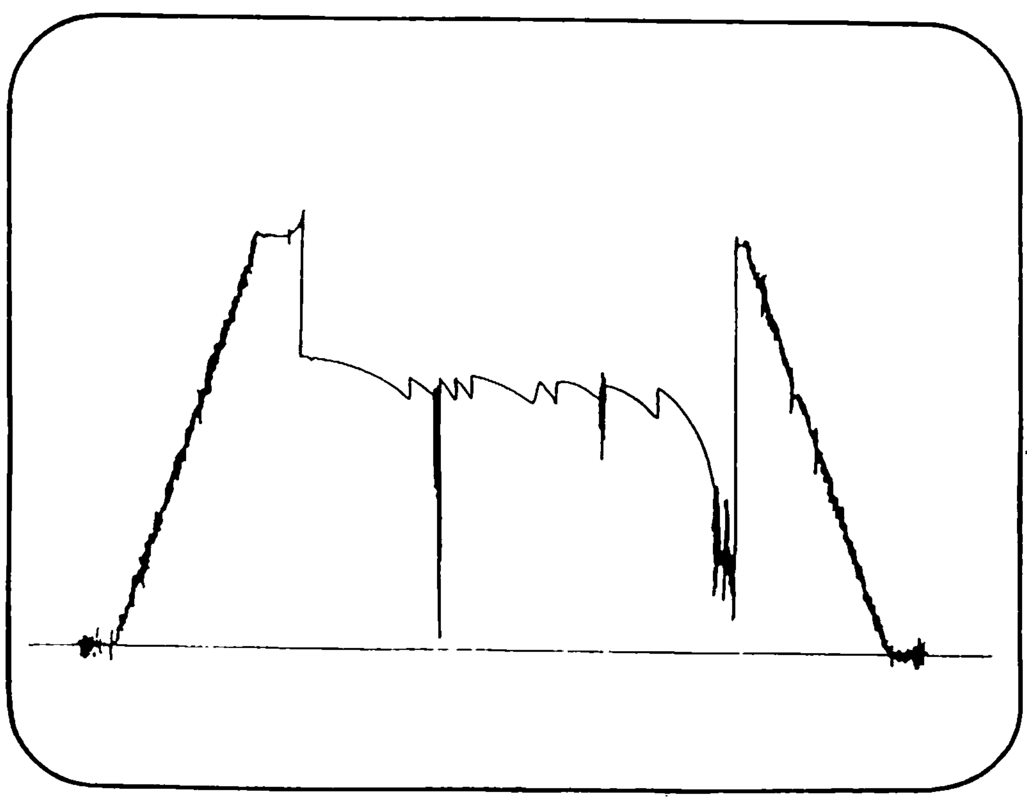


TEST TOOL BY-PASSED

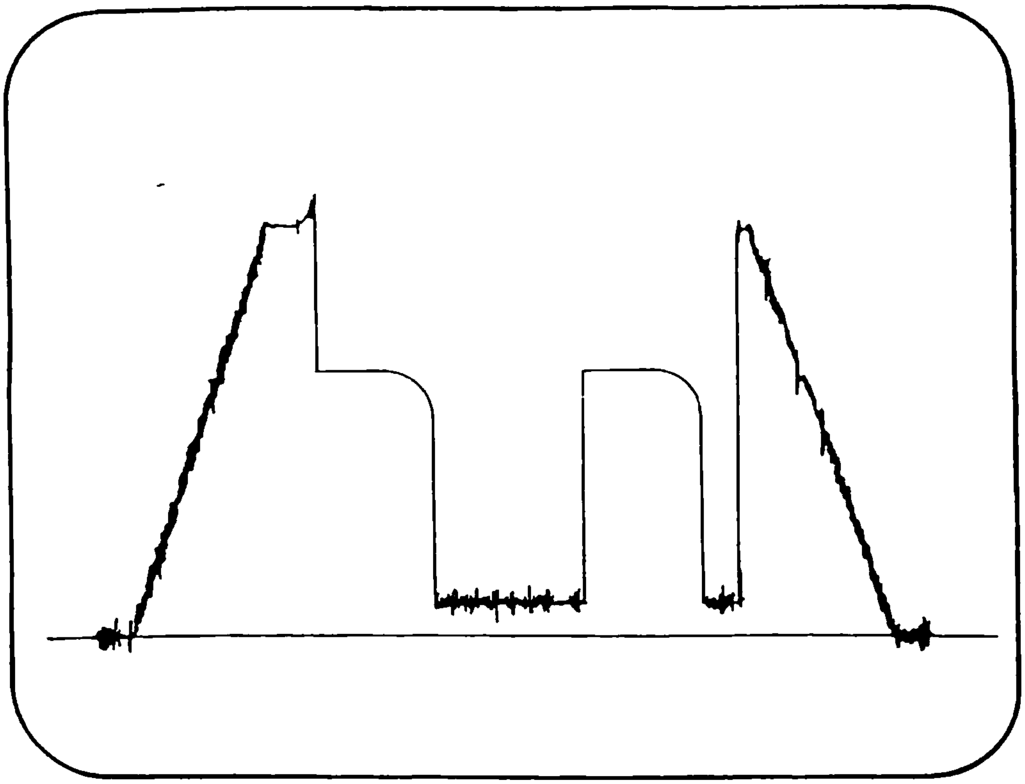
Tool by-passed to hydrostatic o
purpose
This is often done during a no-
blow test to be sure tool and
perforations are open
This normally adds 20' drilling
mud to recovery



SLID TEST TOOL TO BOTTOM
Probably had fill in the bottom of the hole
Hole was conditioned improperly allowing cuttings, shale, etc. to settle on bottom of the hole.
Sliding a test tool to bottom is extremely dangerous. Tool may get stuck on bottom

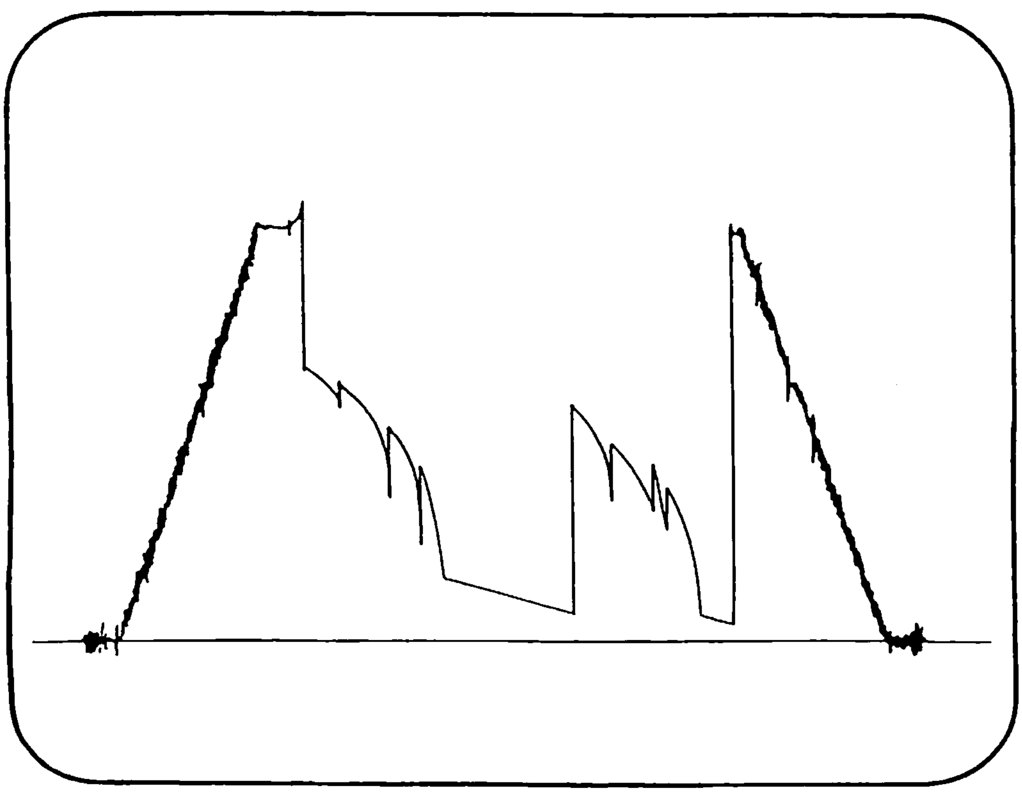


TOOL PLUGGED
All pressures are invalid
Zone was never exposed to atmospheric pressure
Test should be re-run
BHP and Hydrostatic pressure are trapped below test tool



TOOL PLUGGING

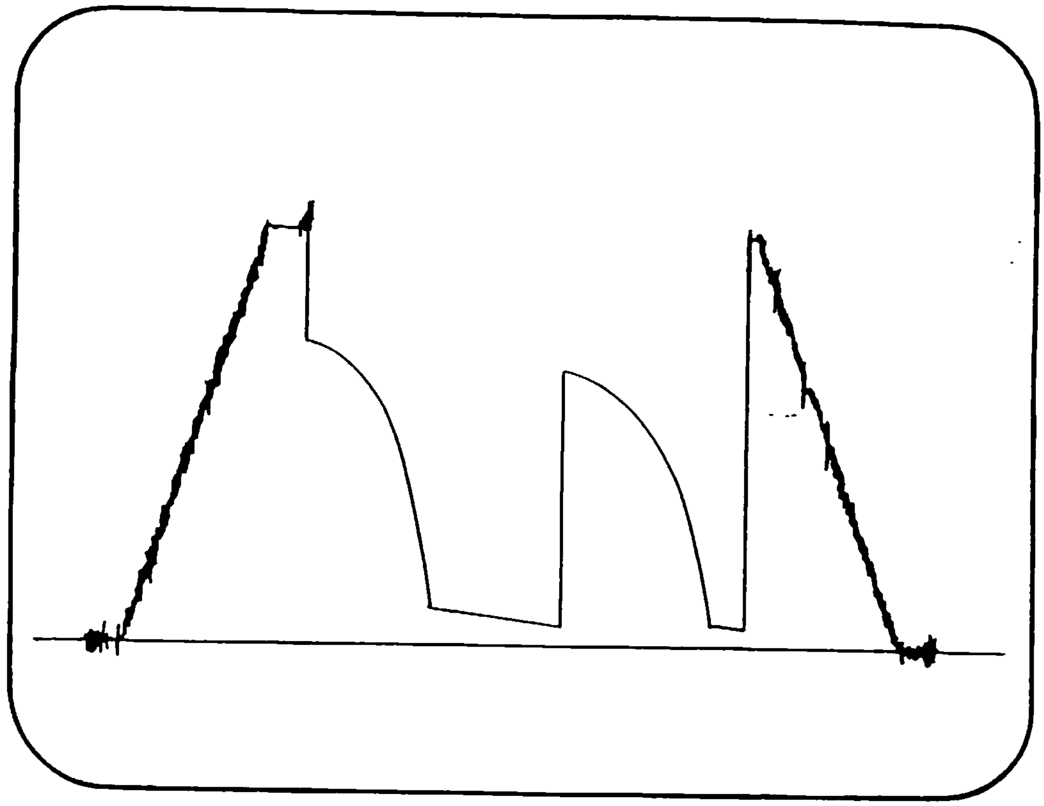
Tool or perforations were pluggin
during flow periods.
Probably.from cuttings, shale, lo
circulation material, etc.
Restricted flow into drill-pipe
reduces the amount of recovery



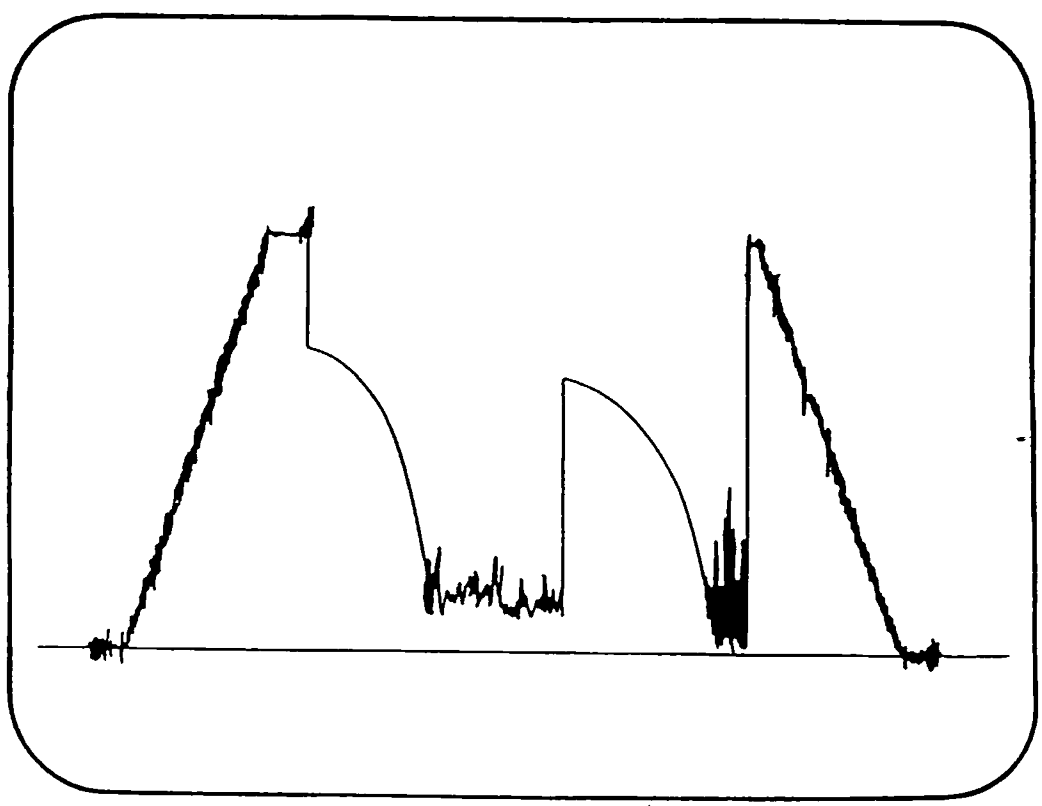
TOOL LEAKING TO OPEN STAGE

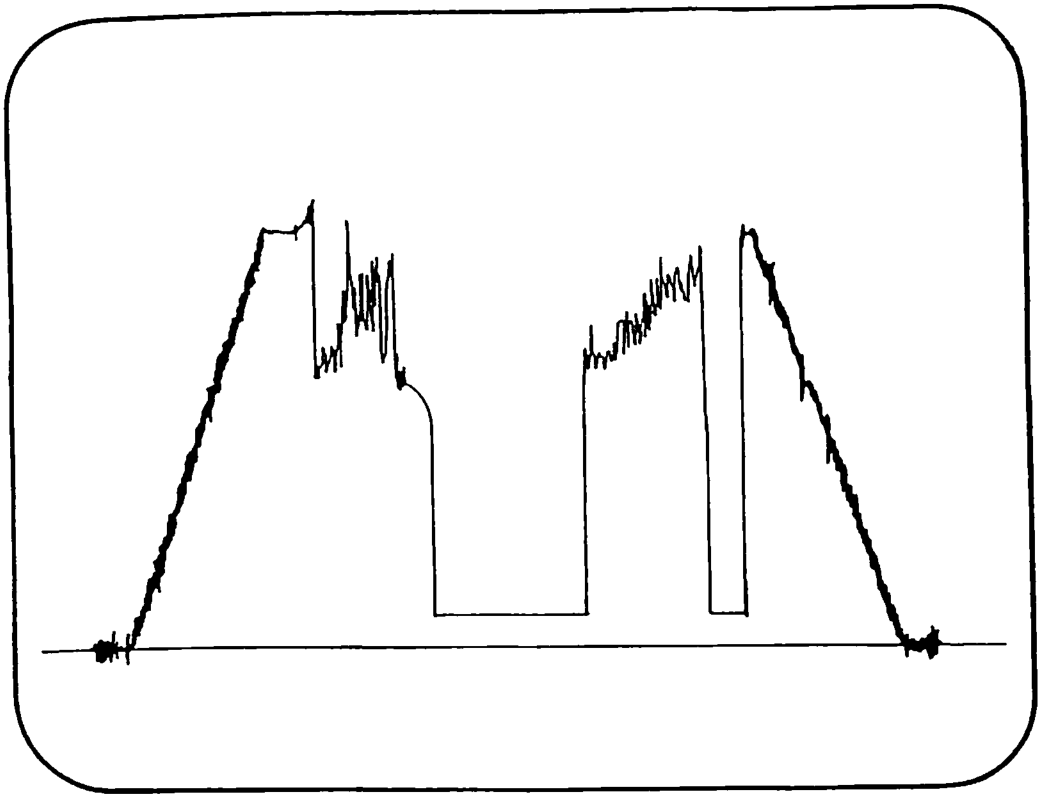
Shut in tool not completely closed
Improper rotation to closed position
B.H.P. false
Test tool leaking
Flow pressure okay
Does not effect recovery

INSIDE RECORDER
Chart looks clean
Pressures could be false
Chart relates to pressure
changes inside anchor and tool



OUTSIDE RECORDER
Recorder reacts to pressure
changes on outside of anchor
This indicates plugging
Normally low fluid recovery
because of anchor plugging





TOOL LEAKING TO HYDROSTATIC

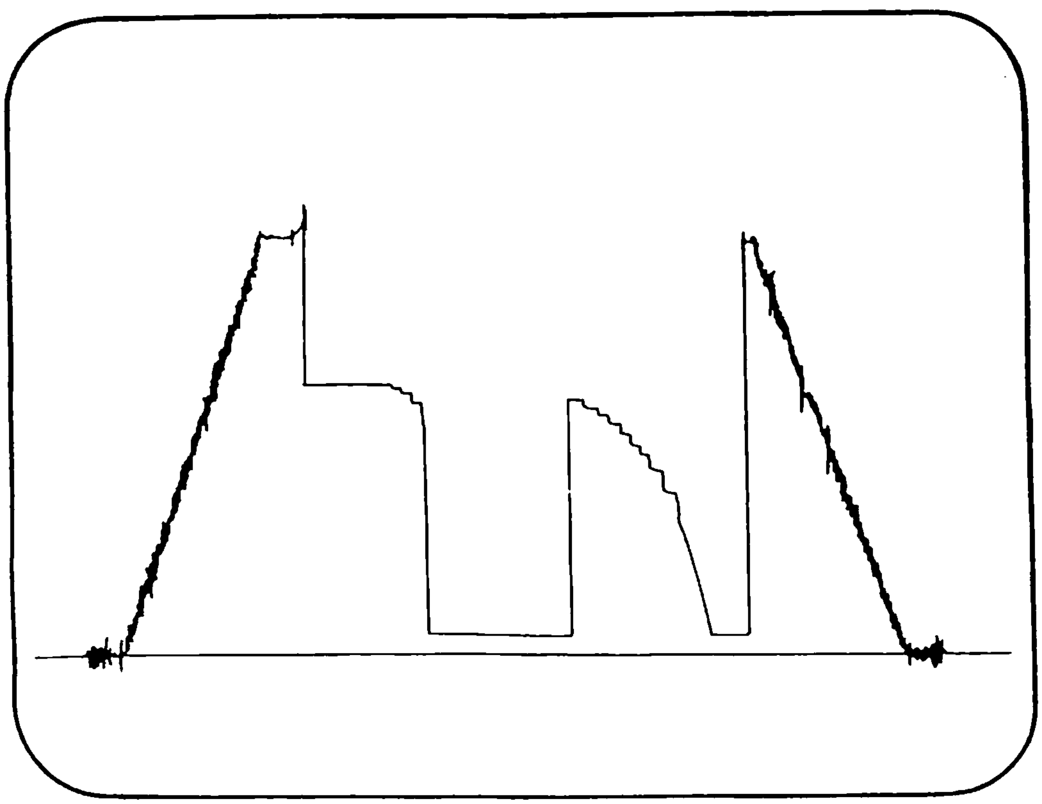
Tool leaking to hydrostatic during B.H.P.

Leak in shut in tool

B.H.P.'s are false

Doesn't effect recovery

Tool sliding or settling during test



STAIR STEPPING

Bottom hole pressure curves reflect

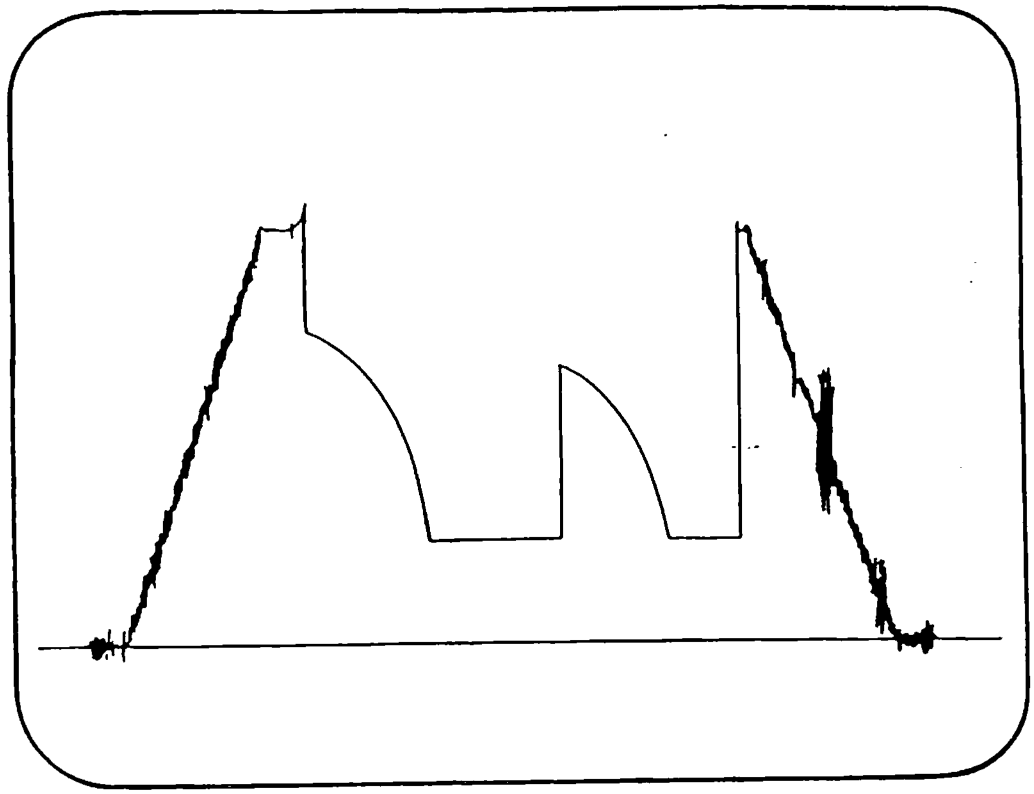
Stair stepping movement

Caused by dirty recorder

Pressure readings valid

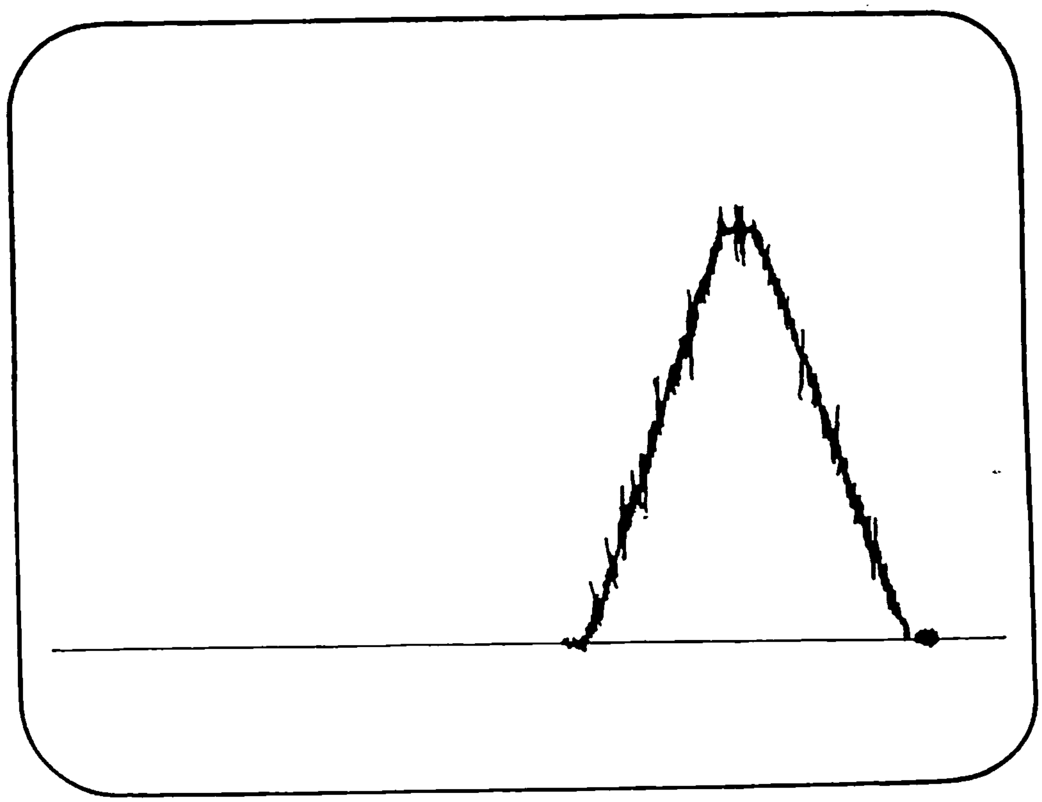
HOLE IN DRILL PIPE

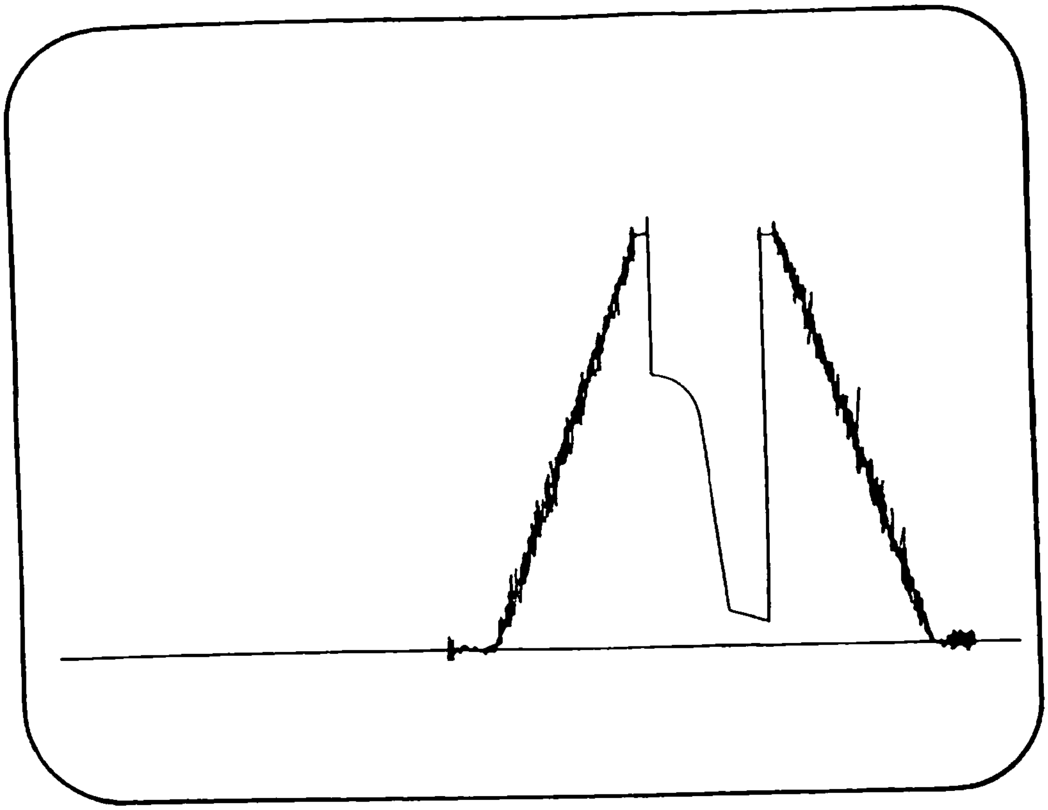
Mud leaked into empty drill pipe
while going in hole
Normally doesn't effect B.H.P.
Flow pressures start high
Drilling mud with recovery



CLOCK STOPPED

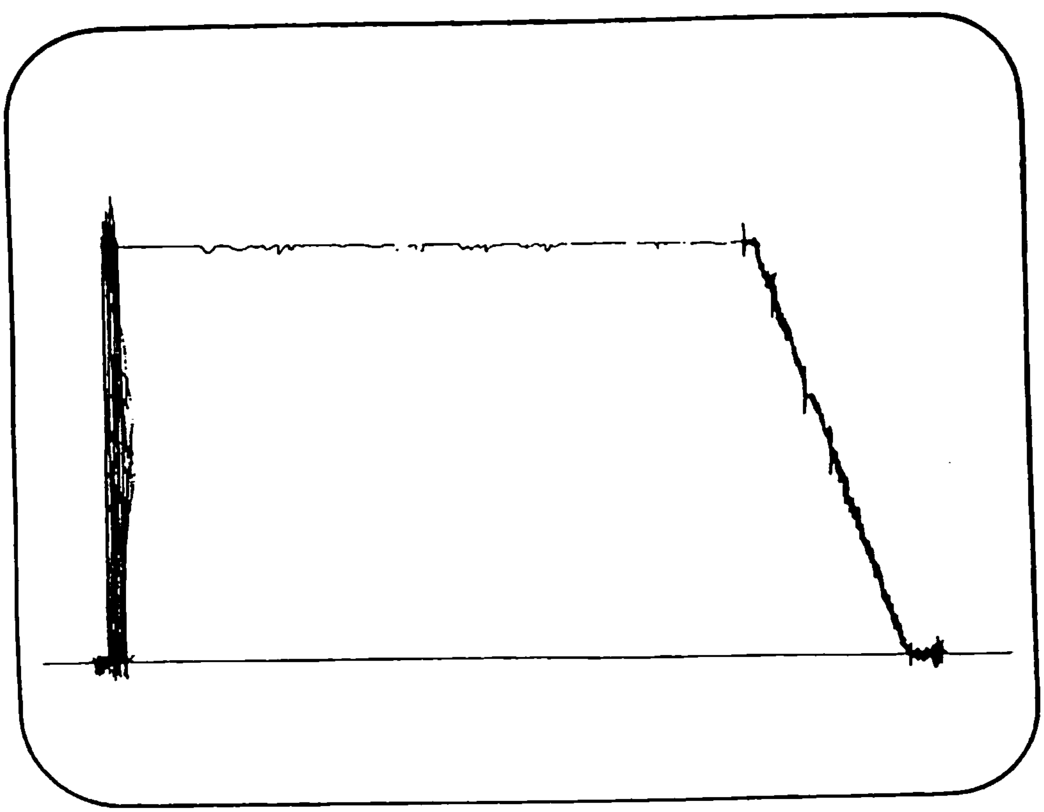
Clock didn't run on bottom
Clocks will often run going in and
out of the hole, but while tool is
stationary on bottom, clock
wouldn't run.





CLOCK STOPPED

Clock stopped during I.B.H.P. tu
can happen any time during test
Often caused by dirty recorder
Pressures that are recorded
are valid



CLOCK RUNNING AWAY

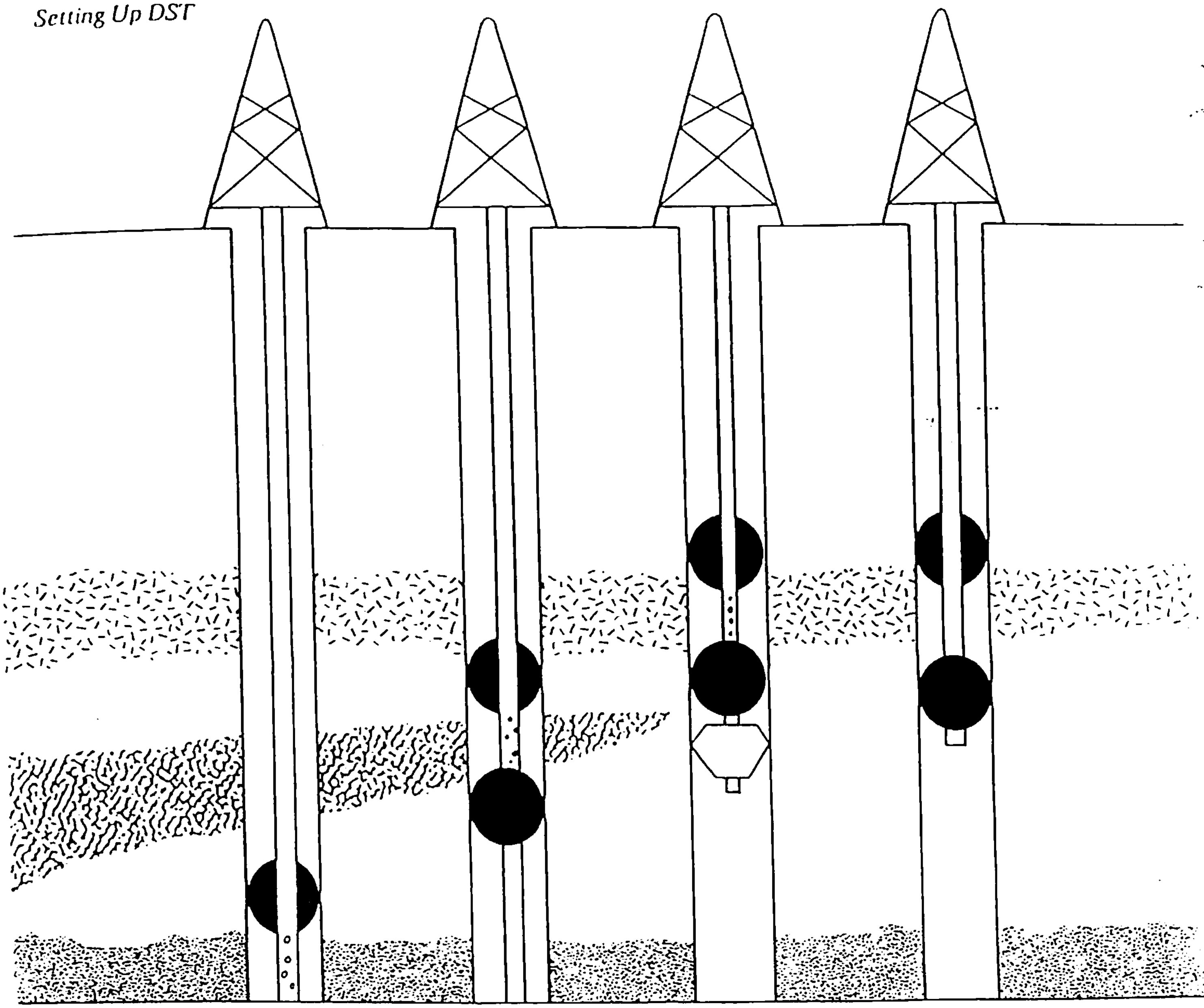
Clock-mechanically poor
Clutch wasn't engaged
No pressures recorded

Setting Up DST with Service Companies

Basic Procedures Which Will Help Facilitate the Running of a DST

1. Identify yourself
2. Oil Company you represent
3. Location of drilling rig and drilling contractor's name
4. Hole size
5. Drill pipe tool joint size
6. Drill collar tool joint size
7. What time tester should be on location (Normally one hour before rig is out of hole)
8. Leave telephone number if company personnel will not be present during actual running of DST
9. Discuss test type (on-bottom, straddle, etc.)
   Length of anchor
   Time Intervals
   Extra equipment
10. Ask for suggestions and approximate cost from service company

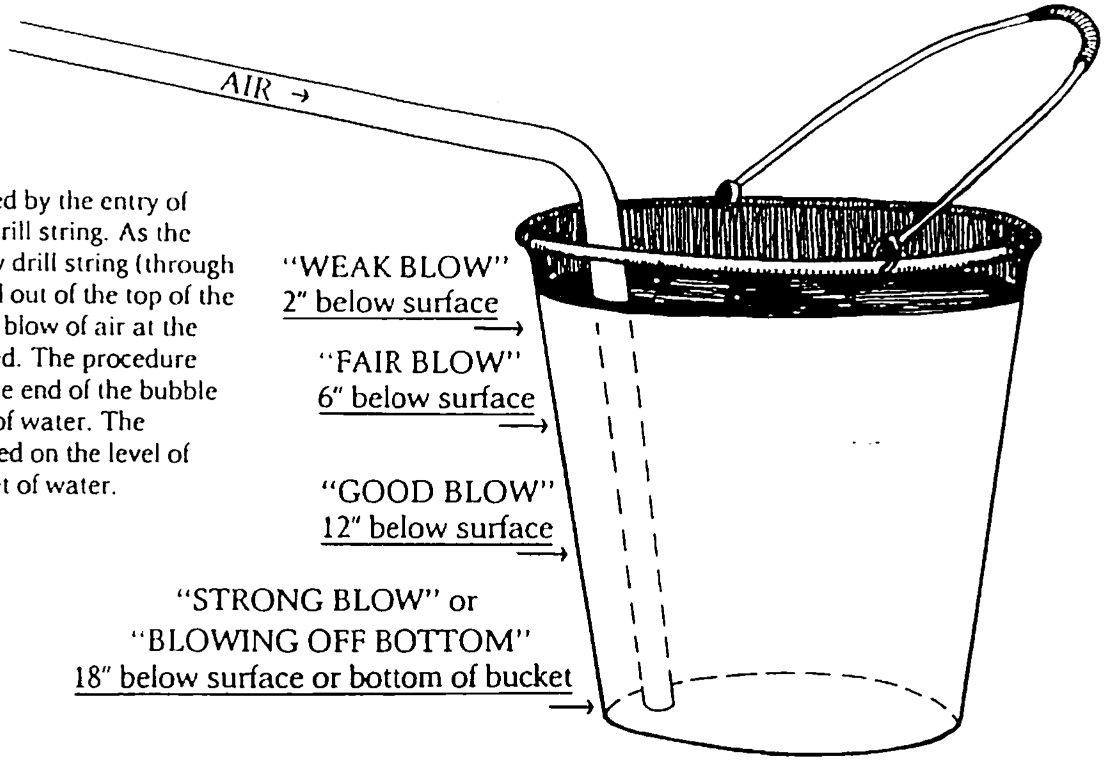
Setting Up DST



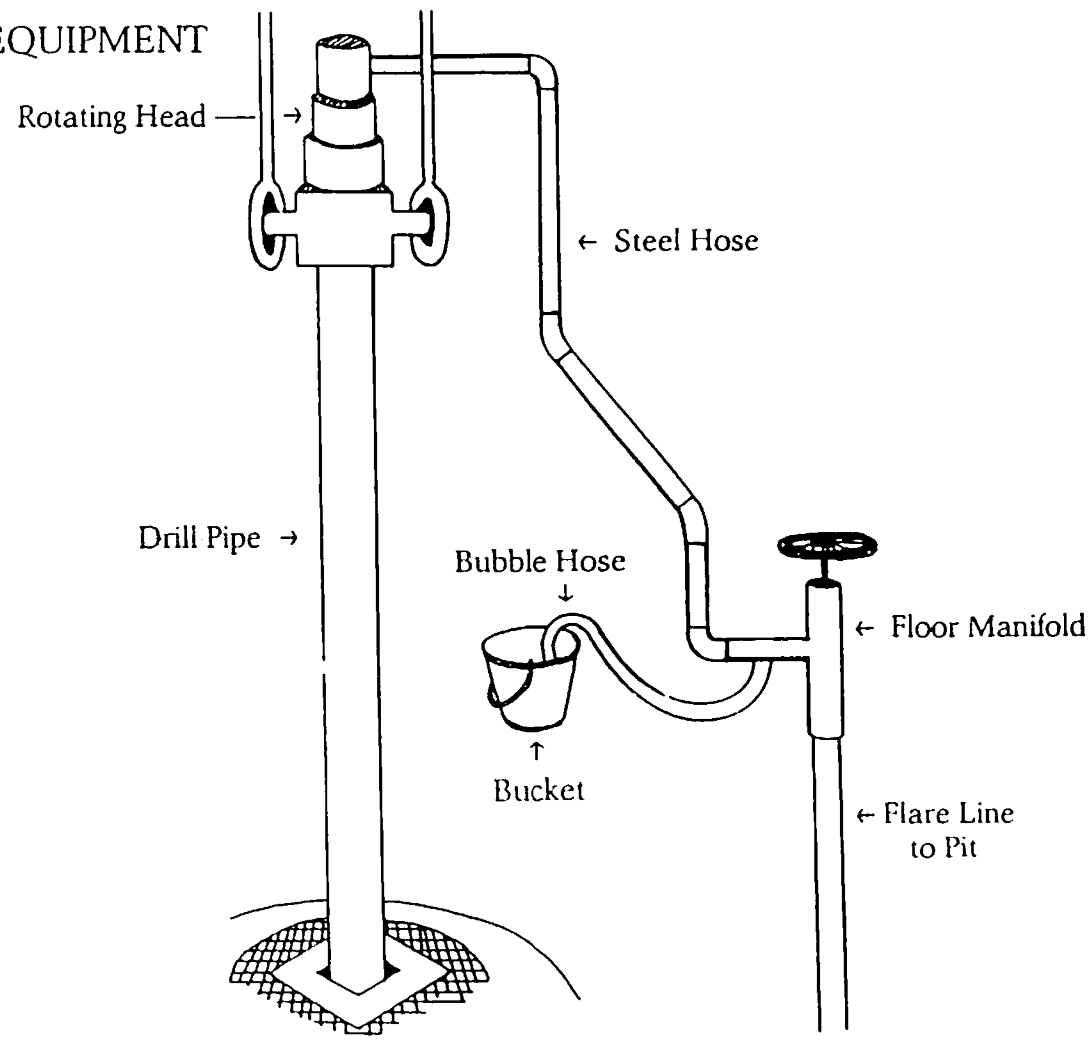
On Bottom	Off Bottom Straddle with Tail Pipe	Off Bottom Straddle with Hook Tool	Off Bottom Straddle with Inflate Packers
With Jars Safety Joint Circulating Sub at 4,500'	With Jars Safety Joint Circulating Sub at 4,500'	With Jars Safety Joint Circulating Sub at 4,500'	With Jars Safety Joint Circulating Sub at 4,500'

SURFACE BLOW

Surface blow action is caused by the entry of fluid or gas into the empty drill string. As the fluid or gas enters the empty drill string (through the test tool) air is displaced out of the top of the drill string. This results in a blow of air at the surface that can be measured. The procedure normally used is to place one end of the bubble hose into a 5 gallon bucket of water. The "BLOW" description is based on the level of bubbling action in the bucket of water.



SURFACE EQUIPMENT



Surface Blow Interpretation

There are some general statements that can be made regarding the interpretation of surface blow on drill stem tests.

1. Weak blow at the surface indicates slow entry of recovery into the drill stem. This can be caused by several things:
   a. Tight zone-low permeability
   b. Plugged anchor or tool
   c. Highly damaged test zone
   d. Low pressure test zone

2. Strong blow at the surface usually indicates that there is rapid entry into the drill stem. This indicates:
   a. Good zone-good permeability
   b. Good pressure

Recommended Flow and Shut-In Times for Drillstem Testing When Experience in the Area is Not Available

Test Period	Situation During Test	Recommended Time	Minimum Time (minutes)
Initial Flow	All	Short — release hydrostatic mud pressure	3 to 5
Initial Shut-In	All	60 minutes unless total test time is too short — 45 minutes then	30
Final Flow	Strong, continuing blow Blow dies Reservoir fluid produced at surface	60 minutes Shut-in when blow dies 60 minutes — longer to gauge flow rates if time is available	60 60
Final Shut-In	Strong continuous blow during flow period Blow dies during flow period Reservoir fluid produced at surface during flow period	Shut-in time equal to flow time Minimum shut-in time of twice flow time Shut-in time equal to flow time	60 Two times flow time 60

Table for Converting Vertical Feet Recovery Into Bbls.

Vertical Feet Recovery	Drill Collars 2.25 I.D. .0049	3½" D.P. 2.76 I.D. .0074	4" D.P. 3.34 I.D. .0108	4½" D.P. 3.82 I.D. .0142	5" D.P. 4.21 I.D. .0178
Feet	Bbls./Rec.	Bbls./Rec.	Bbls./Rec.	Bbls./Rec.	Bbls./Rec
10	.05	.07	.1	.14	.18
20	.1	.14	.2	.28	.35
40	.2	.3	.4	.57	.71
60	.3	.4	.6	.85	1.1
80	.4	.6	.8	1.1	1.4
100	.5	.7	1	1.4	1.8
120	.6	.9	1.3	1.7	2.1
140	.7	1	1.5	2	2.5
160	.8	1.2	1.7	2.3	2.8
180	.9	1.3	1.9	2.5	3.2
200	1	1.5	2.1	2.8	3.5
220	1.1	1.6	2.4	3.1	3.9
240	1.2	1.8	2.6	3.4	4.3
260	1.3	1.9	2.8	3.7	4.6
280	1.4	2	3	4	5
300	1.5	2.2	3.2	4.3	5.3
320	1.6	2.4	3.4	4.5	5.7
340	1.7	2.5	3.7	4.8	6
360	1.8	2.7	3.9	5.1	6.4
380	1.9	2.8	4.1	5.4	6.8
400	2	3	4.3	5.7	7.1
420	2.1	3.1	4.5	6	7.5
440	2.2	3.3	4.7	6.2	7.8
460	2.3	3.4	5	6.5	8.2
480	2.4	3.5	5.2	6.8	8.5
500	2.5	3.7	5.4	7.1	9
550	2.7	4	6	7.8	9.8
600	3	4.4	6.5	8.5	10.7
650	3.2	4.8	7	9.2	11.6
700	3.4	5	7.5	10	12.5
750	3.7	5.5	8.1	10.6	13.3
800	4	6	8.6	11.4	14.2

Vertical Feet Recovery	Drill Collars 2.25 I.D. .0049	3½" D.P. 2.76 I.D. .0074	4" D.P. 3.34 I.D. .0108	4½" D.P. 3.82 I.D. .0142	5" D.P. 4.21 I.D. .0178
Feet	**Bbls./Rec.**	**Bbls./Rec.**	**Bbls./Rec.**	**Bbls./Rec.**	**Bbls./Rec.**
850	4.2	6.3	9.1	12	15.2
900	4.4	6.6	9.7	12.8	16
950	4.6	7	10.2	13.5	17
1000	4.9	7.4	10.8	14.2	17.8
1100	5.4	8.1	11.8	15.6	19.6
1200	5.9	8.8	13	17	21.4
1300	6.4	9.6	14	18.5	23
1400	6.9	10.4	15.1	20	25
1500	7.3	11.1	16.2	21.3	26.7
1600	7.8	11.8	17.3	22.7	28.5
1700	8.3	12.6	18.4	24.1	30.2
1800	8.8	13.3	19.4	25.5	32
1900	9.3	14	20.5	27	34
2000	9.8	14.8	21.6	28.4	35.6
2500	12.3	18.5	27	35.5	44.5
3000	14.7	22.2	32.4	42.6	53.4
3500	17.2	26	37.8	49.7	62.3
4000	19.6	29.6	43.2	56.8	71.2
4500	22	33.3	48.6	64	80
5000	24.5	37	54	71	89

(Barrels recovered ÷ Total time open) (1440) = Bbls/day

Fluid enters the empty drill string, (through the test tool) where it is trapped until the drill string is pulled out of the hole.

Fluid recovery on a DST field ticket is normally reported in "vertical feet recovered."

Example = 60' Oil Cut Mud + 2000' Salt Water

As the fluid recovery is dumped at the surface a visual inspection is made and samples are caught. The tester reports the vertical feet of recovery and describes the fluid. Centrifuging the fluid sample is one of the more accurate ways to describe the recovery.

Example = 60' Oil Cut Mud (40% Oil + 60% Mud)

Most testing companies furnish centrifuges, chloride kits, fluid and gas sample bottles, hydrometers, etc. with the test truck.

SALINITY CONVERSION TABLE

Percent Salt	ppm/Chlor	Mg/l	#/gal.	Specific Gravity	psi/ft
1	10,000	10,050	8.39	1.007	.436
2	20,000	20,250	8.45	1.014	.439
3	30,000	30,700	8.51	1.022	.443
4	40,000	41,100	8.57	1.029	.446
5	50,000	52,000	8.63	1.036	.449
6	60,000	62,500	8.69	1.043	.452
7	70,000	73,000	8.75	1.050	.455
8	80,000	84,500	8.81	1.058	.458
9	90,000	95,000	8.87	1.065	.461
10	100,000	107,100	8.93	1.072	.464
11	110,000	118,500	8.99	1.079	.467
12	120,000	130,300	9.06	1.088	.471
13	130,000	142,000	9.13	1.096	.475
14	140,000	154,100	9.19	1.103	.478
15	150,000	166,500	9.25	1.110	.481
16	160,000	178,600	9.31	1.118	.484
17	170,000	191,000	9.38	1.126	.489
18	180,000	203,700	9.45	1.134	.491
19	190,000	216,500	9.51	1.142	.495
20	200,000	229,600	9.58	1.150	.498
21	210,000	243,000	9.64	1.157	.501
22	220,000	256,100	9.71	1.166	.505
23	230,000	270,000	9.78	1.174	.509
24	240,000	279,500	9.85	1.182	.512
25	250,000	283,300	9.92	1.191	.516
26	260,000	311,300	9.99	1.199	.519

Gas Terms

1,500,000	CFG	Cubic Feet Gas
1,500	MCFG	Thousand Cubic Feet Gas
1.5	MMCFG	Million Cubic Feet Gas

Gas Volumes

In computing gas volumes, the operator should be guided by the following statutory definition:

The term 'cubic foot of gas' or 'standard cubic foot of gas' means the volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the above standard, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the Ideal Gas Laws, corrected for deviation.

Basic Positive Choke Factors
MCFD/PSIA

Multiply upstream pressure (PSIA) by appropriate coefficient = (answer in MCF/Day).

This applies only if you are flowing dry gas through a properly calibrated and properly zeroed choke under critical conditions. A gas is normally in critical flow as long as the upstream pressure is at least twice the downstream pressure.

Based on: Gas Gravity = 1.0 Gas Temperature = 60 F.

Choke Size	Adj. Equivalent	Dec. Equivalent	Coef. (6 in Nipple)
1/ 8	8/64	.1250	0.2696
9/64	9/64	.1406	0.3438
5/32	10/64	.1563	0.4274
11/64	11/64	.1719	0.5204
3/16	12/64	.1875	0.6228
13/64	13/64	.2031	0.7374
7/32	14/64	.2188	0.8623
15/64	15/64	.2344	0.9974
1/ 4	16/64	.2500	1.1430
17/64	17/64	.2656	1.2960
9/32	18/64	.2813	1.4580
19/64	19/64	.2969	1.6310
5/16	20/64	.3125	1.8130
21/64	21/64	.3281	2.0050
11/32	22/64	.3438	2.2070
23/64	23/64	.3594	2.4180
3/ 8	24/64	.3750	2.6400
25/64	25/64	.3906	2.8810
13/32	26/64	.4063	3.1130
27/64	27/64	.4219	3.3970
7/16	28/64	.4375	3.6720
29/64	29/64	.4531	3.9530
15/32	30/64	.4688	4.2450
1/ 2	32/64	.5000	4.8610
9/16	36/64	.5625	6.2190
5/ 8	40/64	.6250	7.7520
11/16	44/64	.6875	9.4230
3/ 4	48/64	[illegible]	[illegible]

Formation Damage Determination from Shut-Ins

Formation damage is a zone of reduced permeability near the wellbore. The flowing capability of the zone is restricted. A low recovery on a test may be the result of damage rather than poor producing ability. Drill stem tests are perhaps, the best way to determine the presence of wellbore damage. It does not define the cause but it does estimate the presence and magnitude of damage.

Cause of Damage

1. Invasion of filtrate (clay content/chemical imbalance)
2. Invasion of solids
3. Mechanical damage

Filtrate invasion occurs when a zone has permeability and the mud system has a potential for water loss. The hydrostatic mud weight, water loss properties of the mud, and the chemical-osmotic potentials between the mud and formation determine the amount of filtrate that enters the formation. Water absorption in swelling clays such as smectite, kaolinite or mixed layer clays can reduce the effective permeabilities.

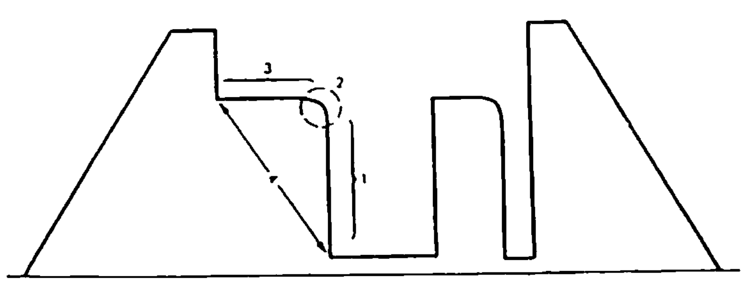
Solids invasion occurs when a zone has high permeability and a large pressure differential between hydrostatic and formation pressure. Drilling mud can be packed into the wellbore. The solids may be immobile when testing owing to the viscosities and pore geometries.

Mechanical damage is induced by the rotary drilling procedure. Often fine particles, created by the grinding of rock chips, are forced into the wellbore.

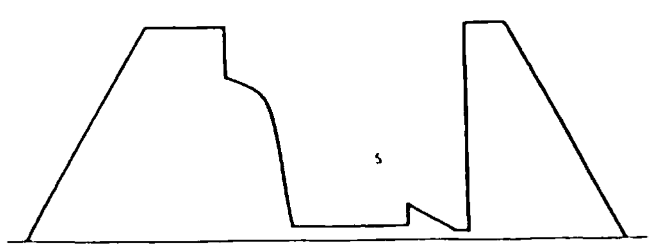
Criteria for Determining Formation Damage

1) Sharp rise on first minutes of shut-in period indicating good permeability.
2) Short radius of curve on shut-in build-up.
3) Reasonably flat slope suggesting shut-in near stabilization.
4) High differential pressure between final shut-in and final flow pressure. The test must have low flowing pressures.

Example Chart:



5) Change of slopes between initial and final shut-in's, where final shut-in slope is steeper than the initial shut-in suggesting an increase in permeability away from the wellbore.

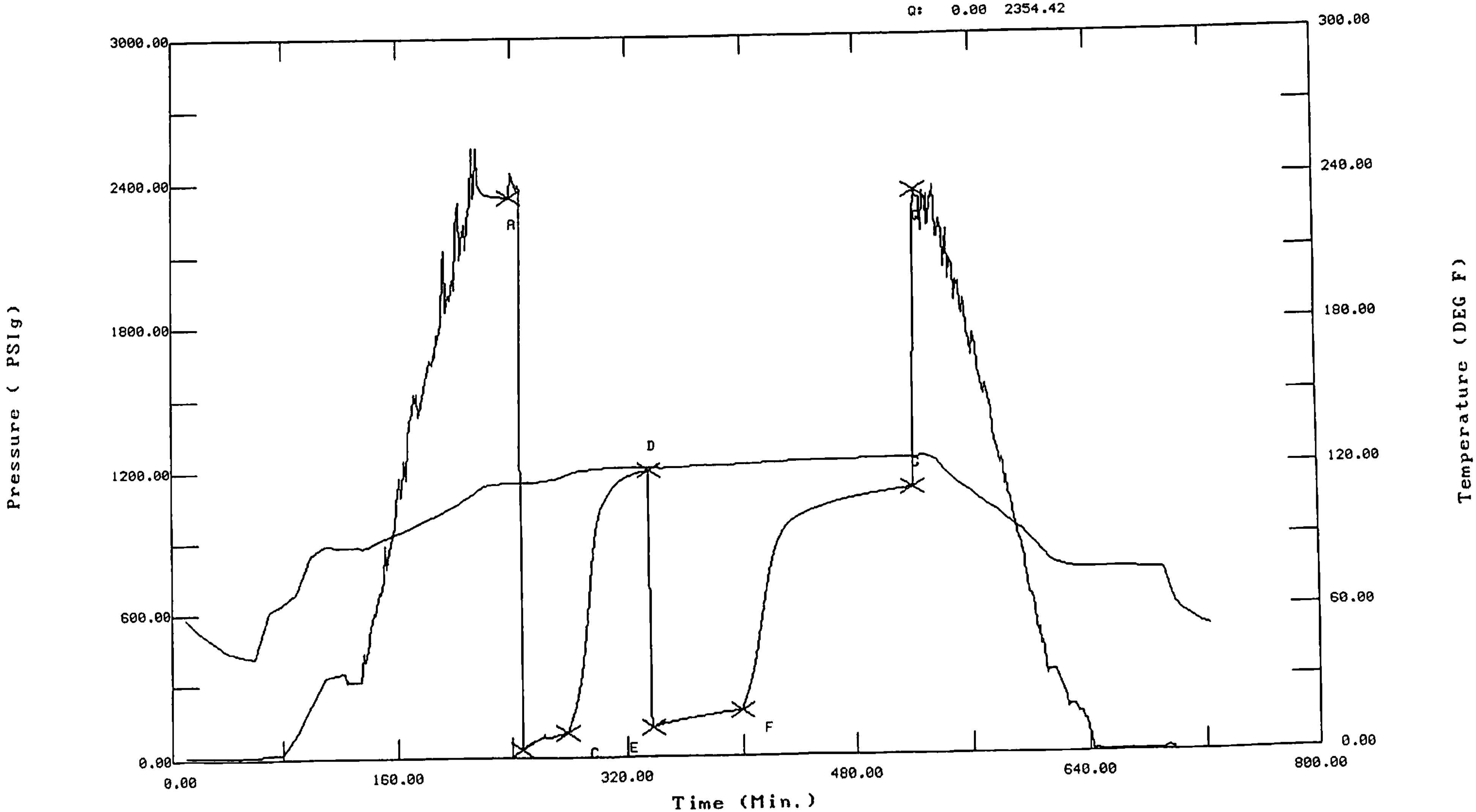


TEST HISTORY

Depleting Shutin

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2341.33
B:	0.00	29.11
C:	32.00	96.09
D:	57.00	1202.09
E:	0.00	113.88
F:	62.00	180.77
C:	119.00	1115.39
Q:	0.00	2354.42

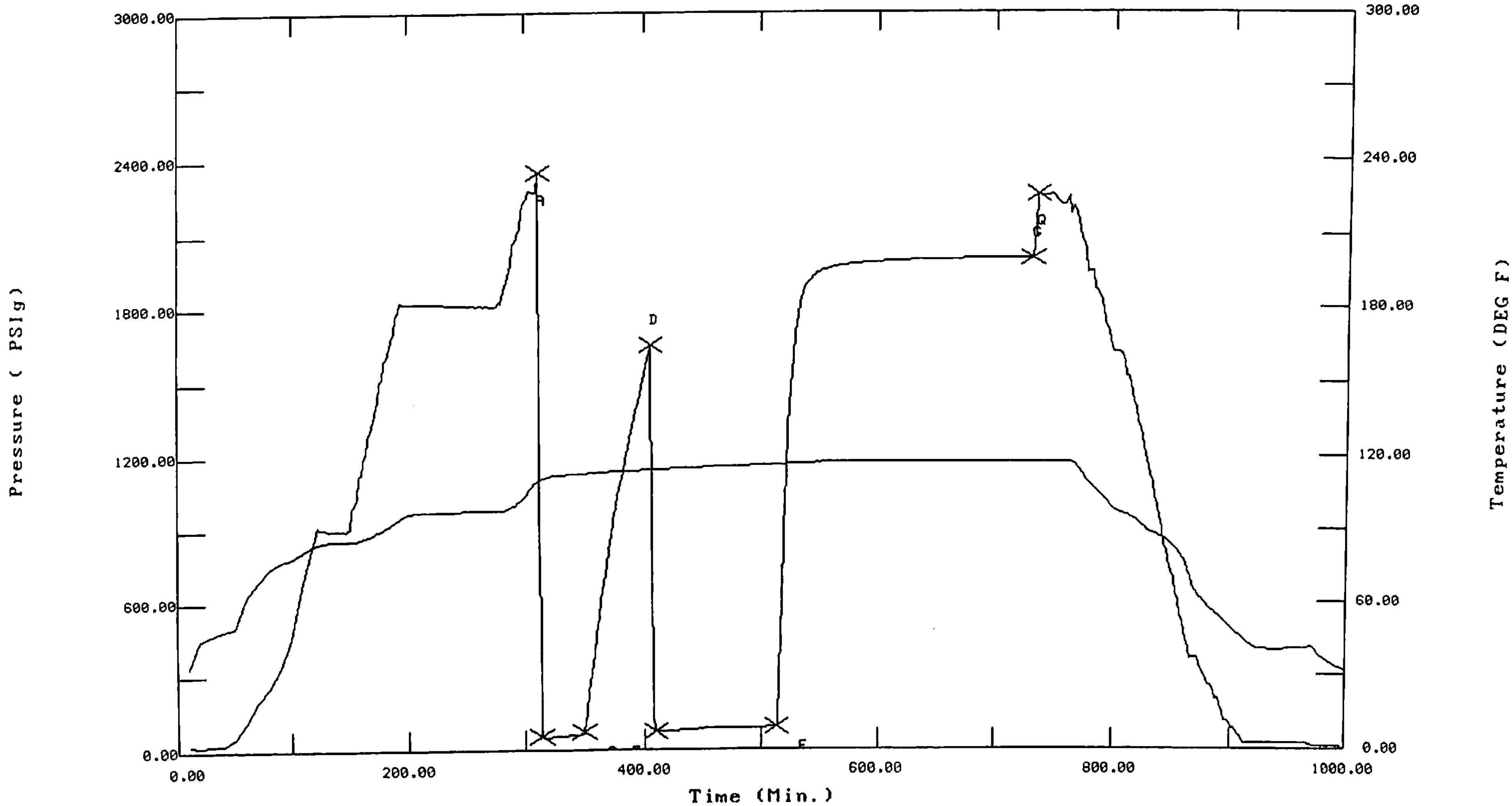


TEST HISTORY

Low perm high pressure gas zone

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2351.06
B:	0.00	49.34
C:	36.00	70.41
D:	56.00	1650.01
E:	0.00	69.23
F:	104.00	88.20
G:	218.00	2005.78
Q:	0.00	2260.67

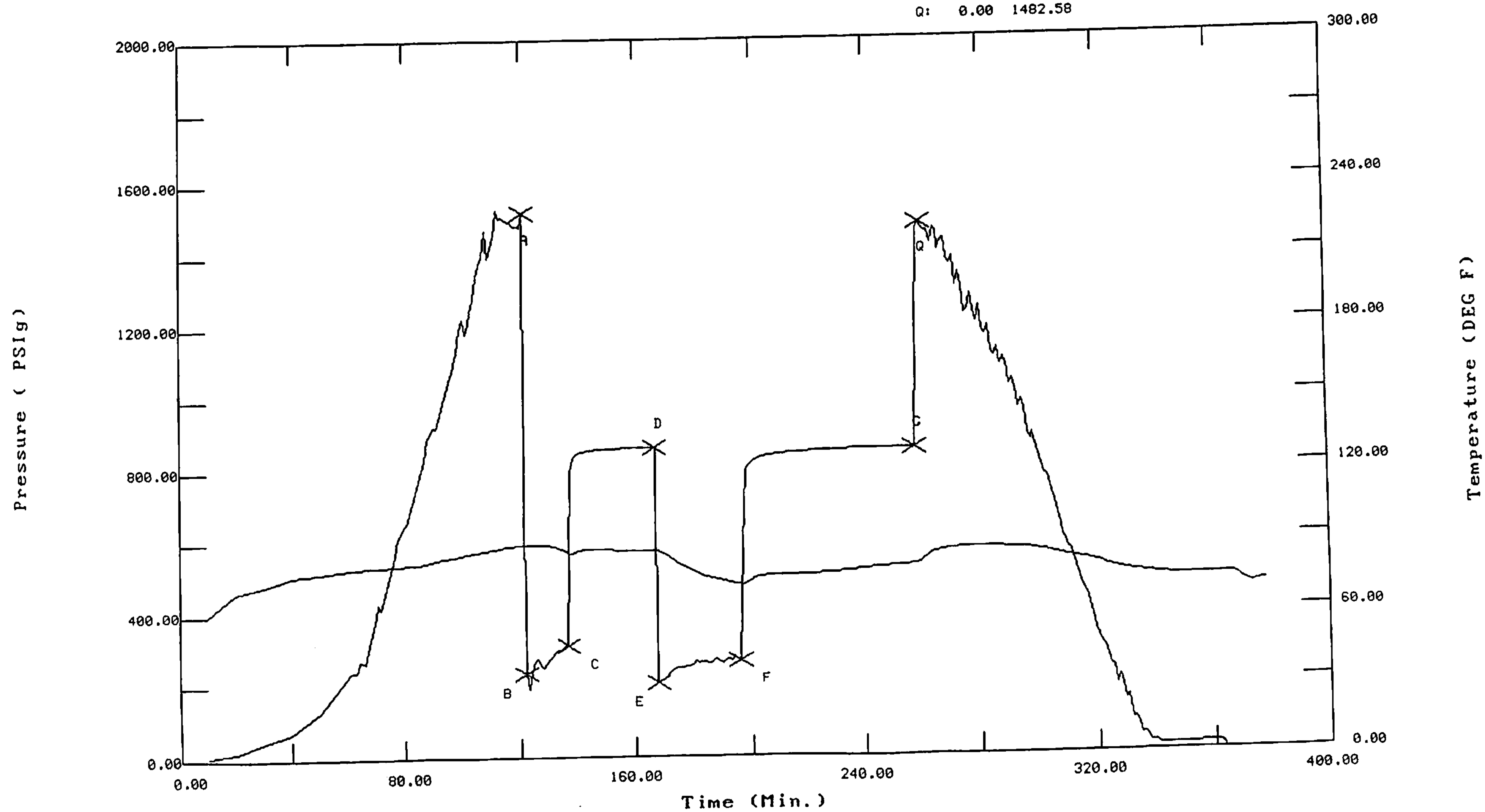


TEST HISTORY

gas test high skin effect

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1520.43
B:	0.00	228.86
C:	15.00	312.12
D:	30.00	863.11
E:	0.00	201.67
F:	28.00	267.47
G:	61.00	857.15
Q:	0.00	1482.58

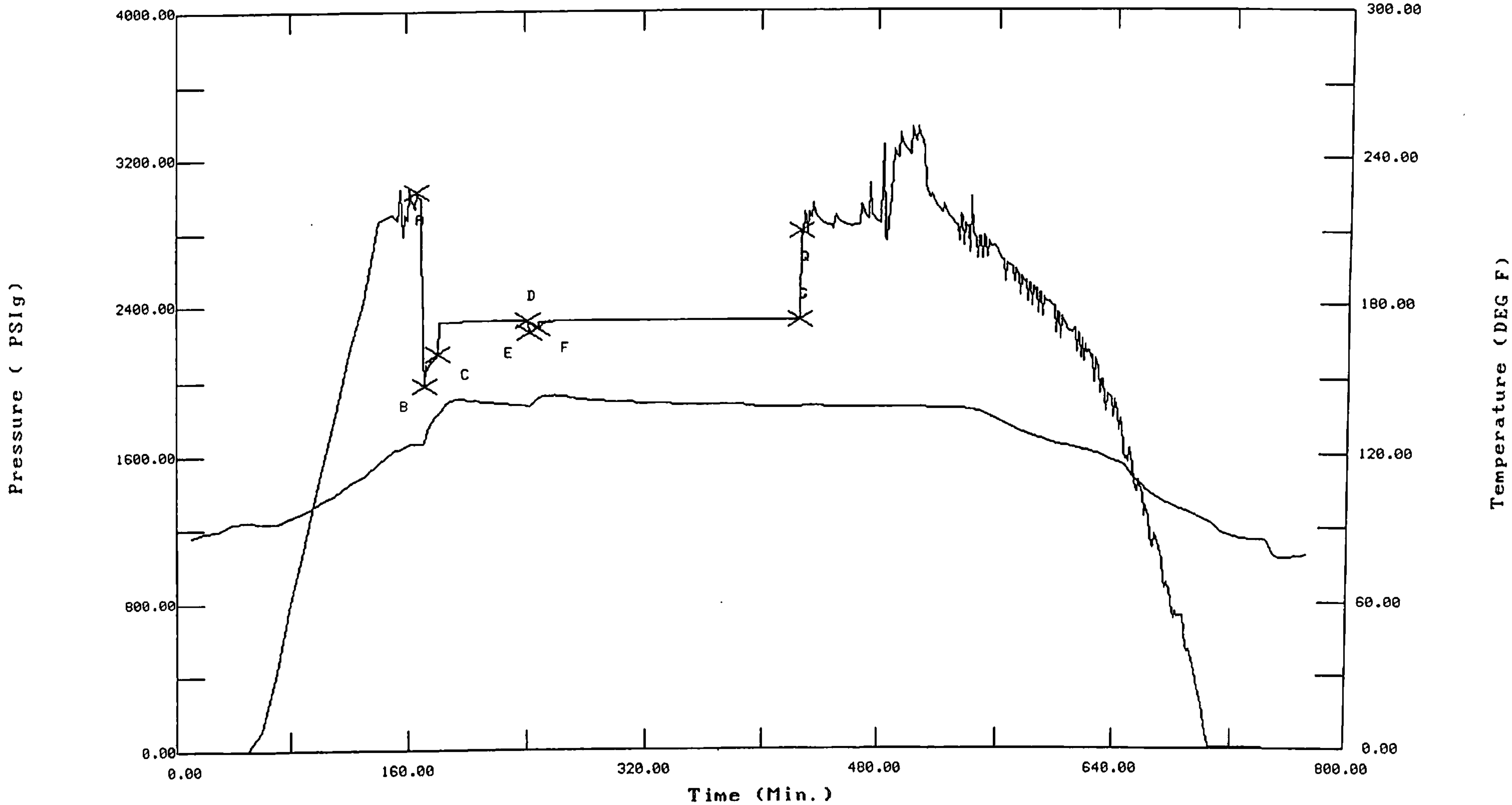


TEST HISTORY

Flowing oil test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	3025.56
B:	0.00	1975.29
C:	9.00	2142.66
D:	61.00	2317.76
E:	0.00	2255.63
F:	5.00	2276.44
G:	179.00	2318.22
Q:	0.00	2806.66

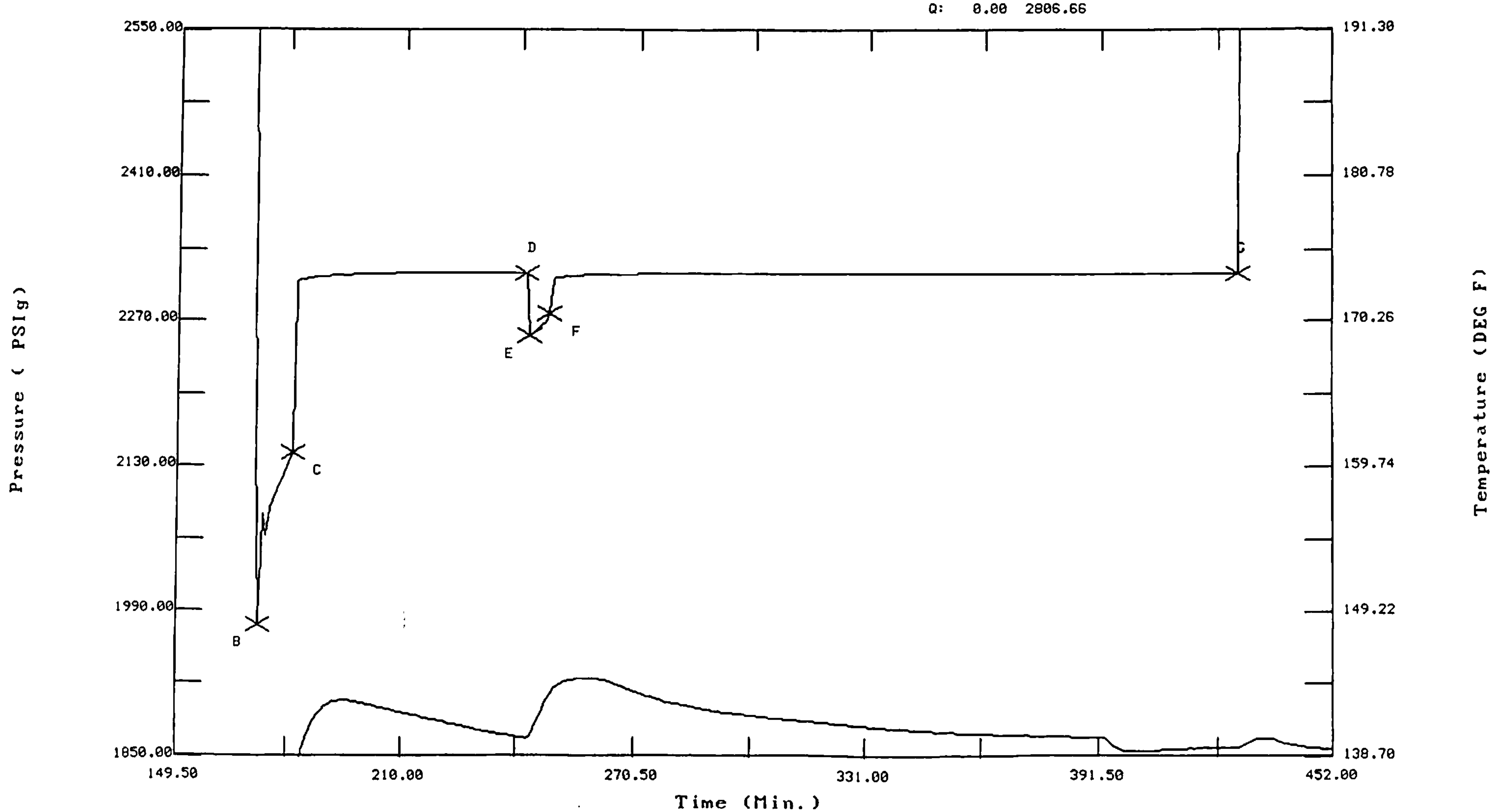


TEST HISTORY

Flowing oil test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	3025.56
B:	0.00	1975.29
C:	9.00	2142.66
D:	61.00	2317.76
E:	0.00	2255.63
F:	5.00	2276.44
C:	179.00	2318.22
Q:	0.00	2806.66

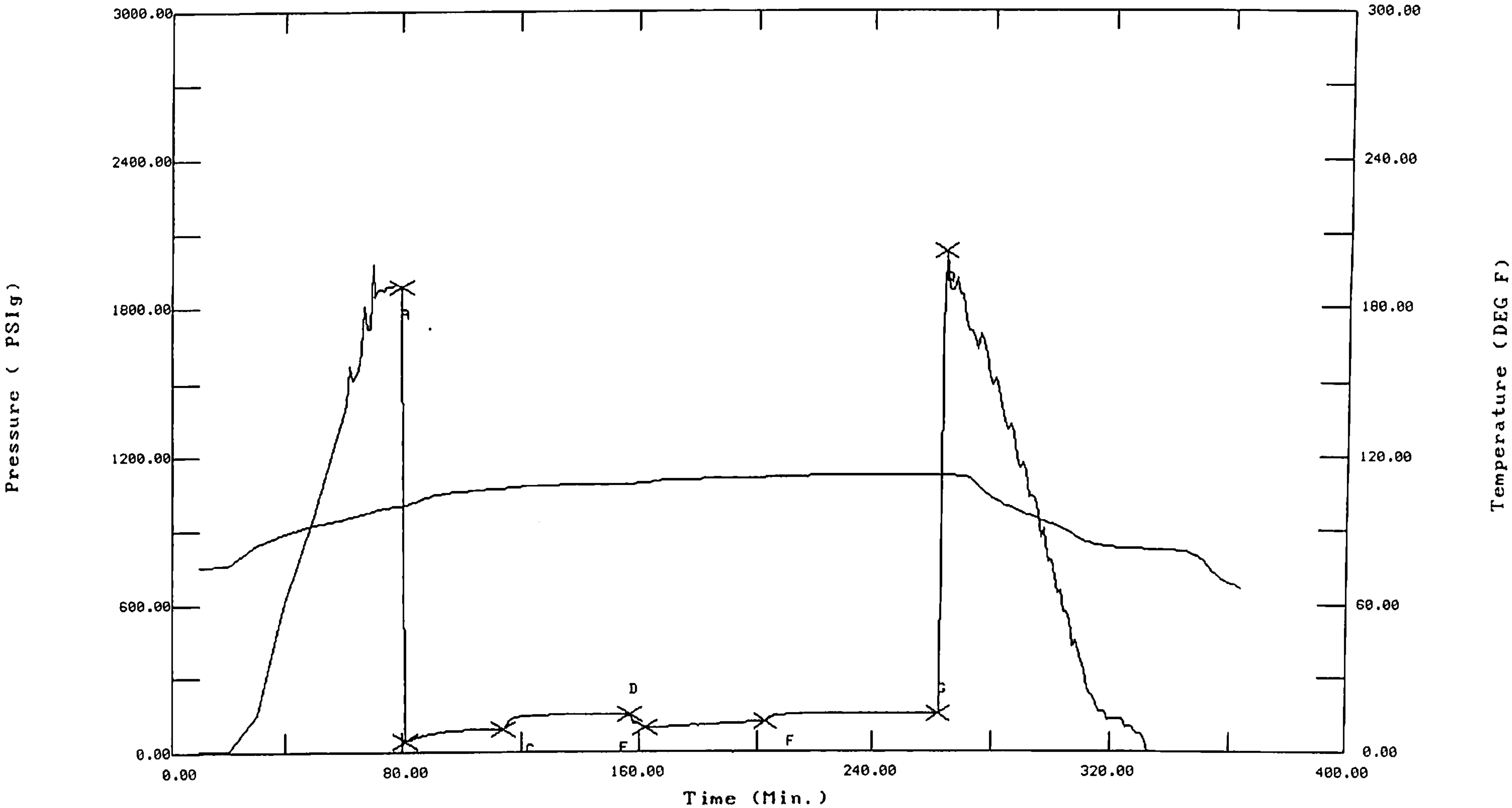


TEST HISTORY

Low pressure high perm oil test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1886.95
B:	0.00	37.96
C:	33.00	86.98
D:	43.00	147.73
E:	0.00	93.77
F:	41.00	117.68
G:	59.00	149.01
Q:	0.00	2028.30

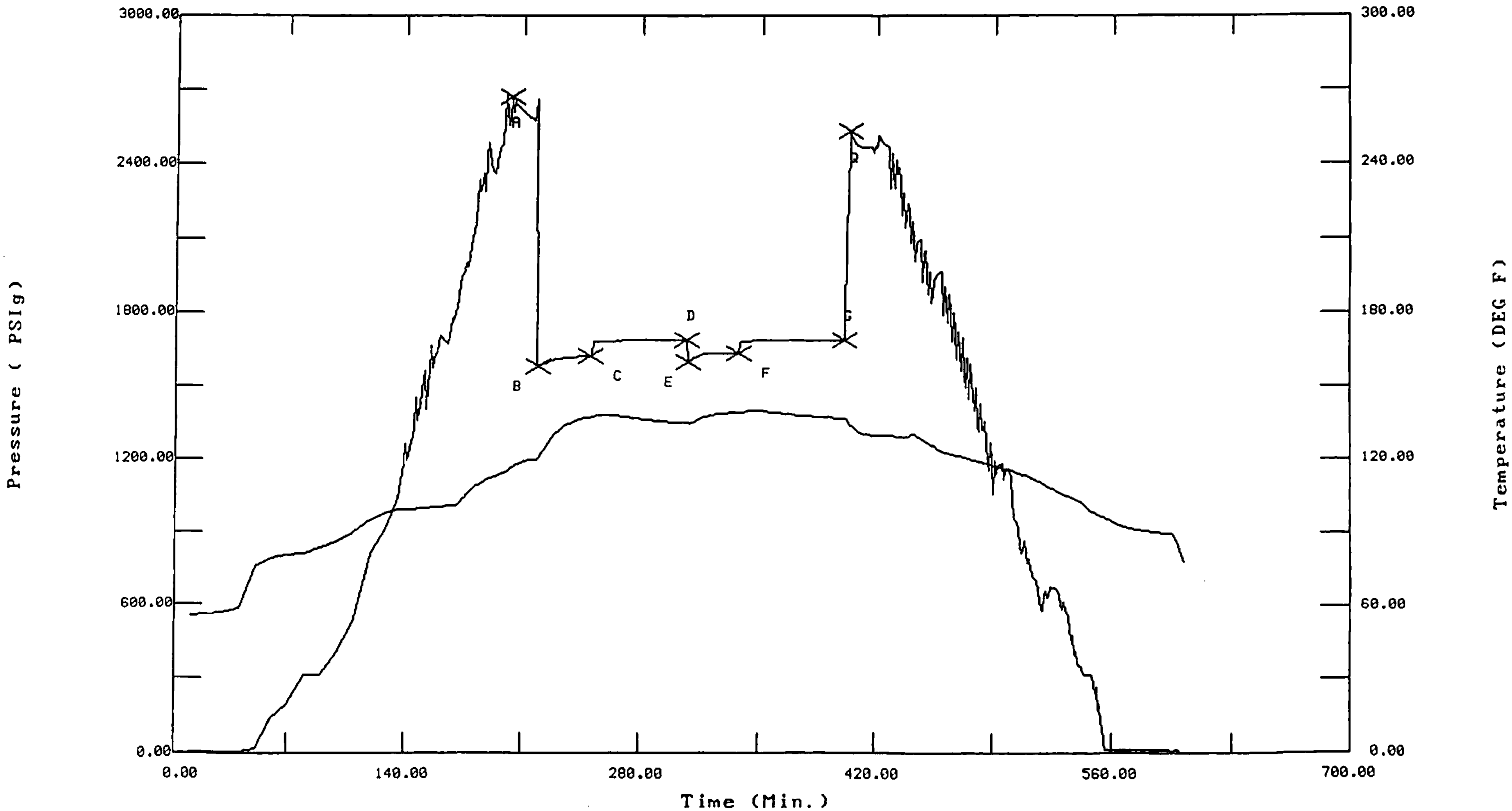


TEST HISTORY

Big Gas Test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2674.10
B:	0.00	1578.09
C:	31.00	1617.03
D:	57.00	1683.50
E:	0.00	1593.53
F:	29.00	1631.88
G:	63.00	1684.38
Q:	0.00	2535.20

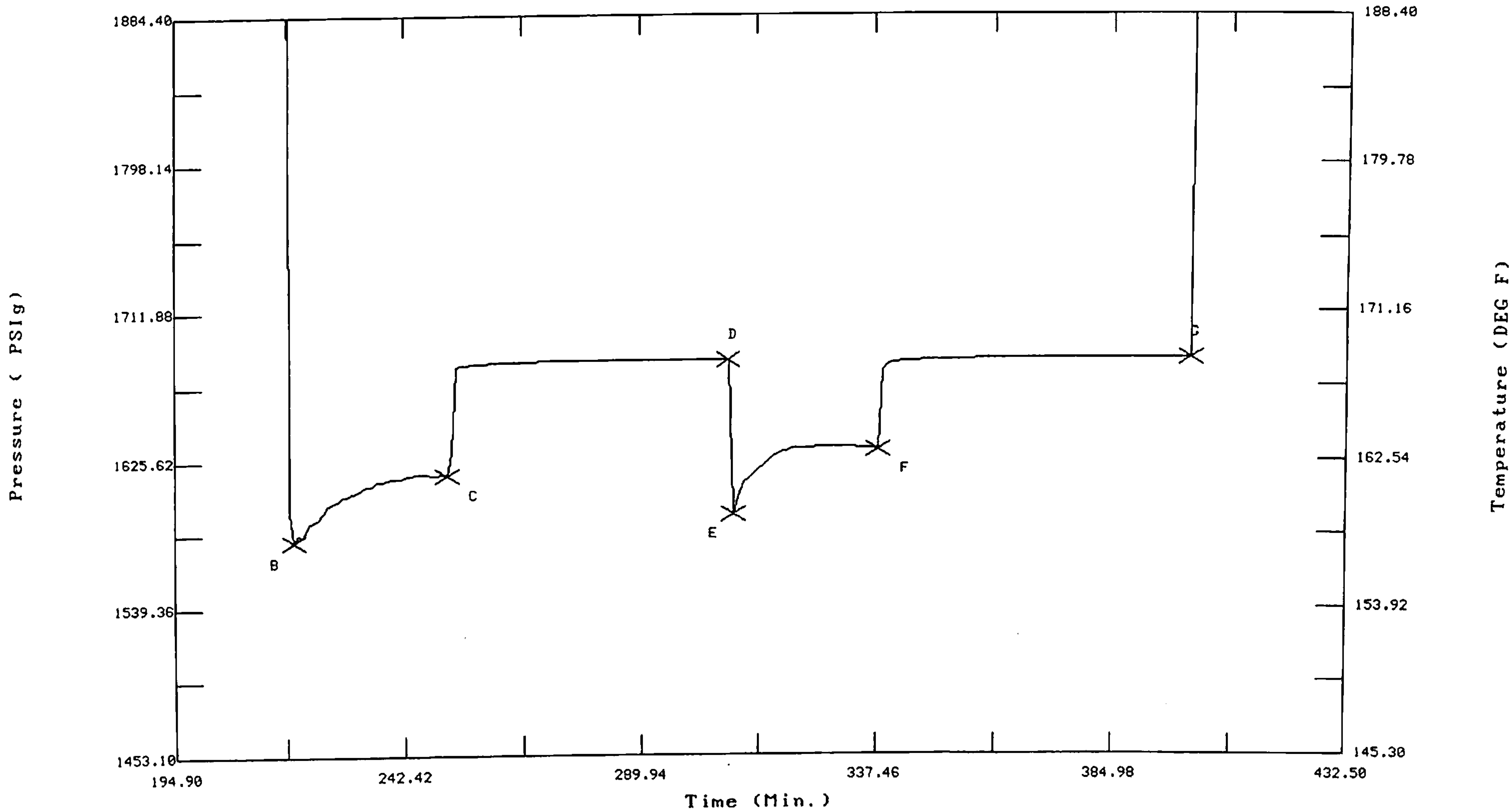


TEST HISTORY

Big Gas Test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2674.10
B:	0.00	1578.09
C:	31.00	1617.03
D:	57.00	1683.50
E:	0.00	1593.53
F:	29.00	1631.88
G:	63.00	1684.38
Q:	0.00	2535.20

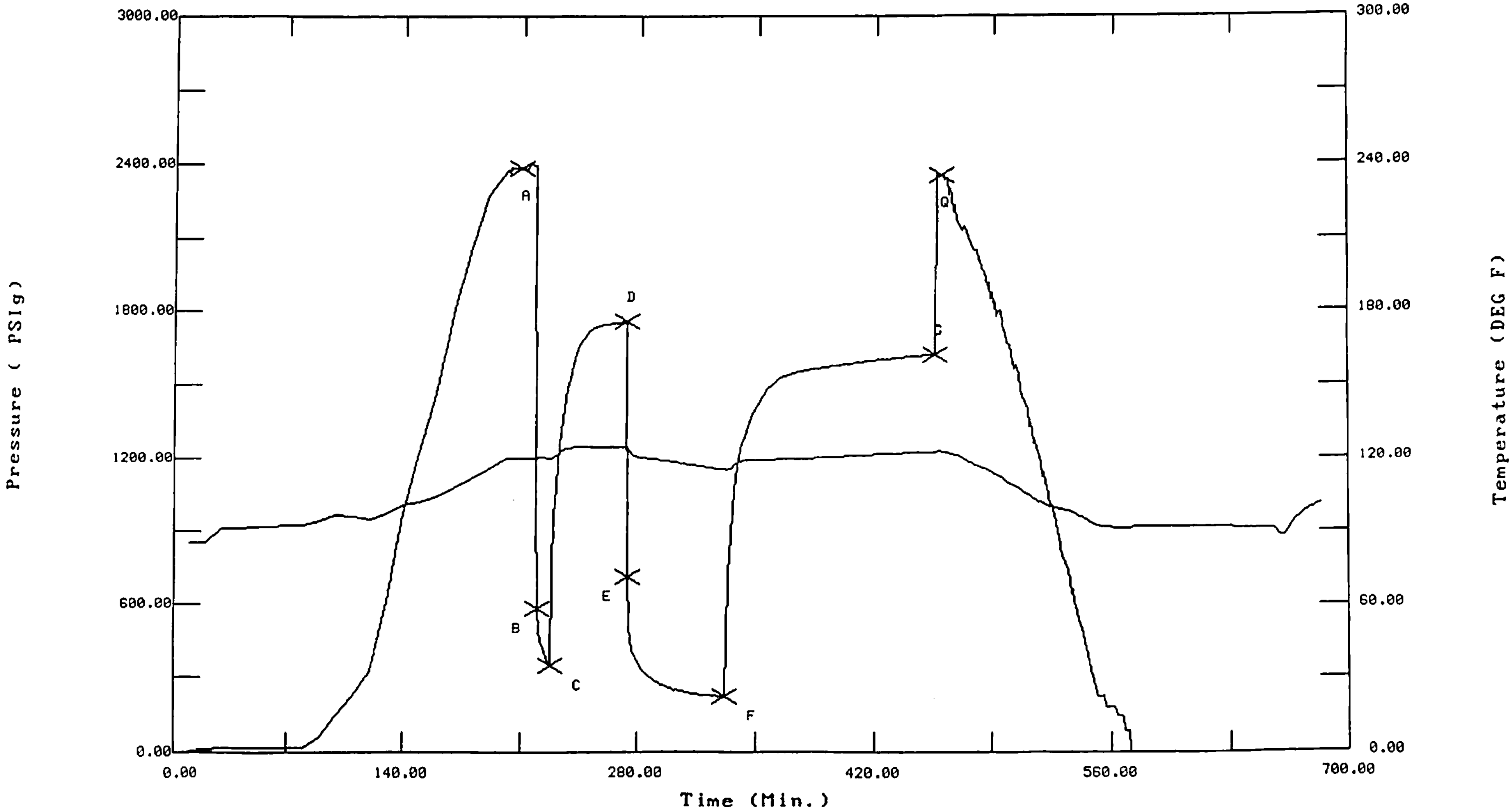


TEST HISTORY

Depleting gas test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2380.86
B:	0.00	581.95
C:	8.00	348.38
D:	45.00	1756.85
E:	0.00	710.78
F:	58.00	221.06
G:	123.00	1621.64
Q:	0.00	2353.75

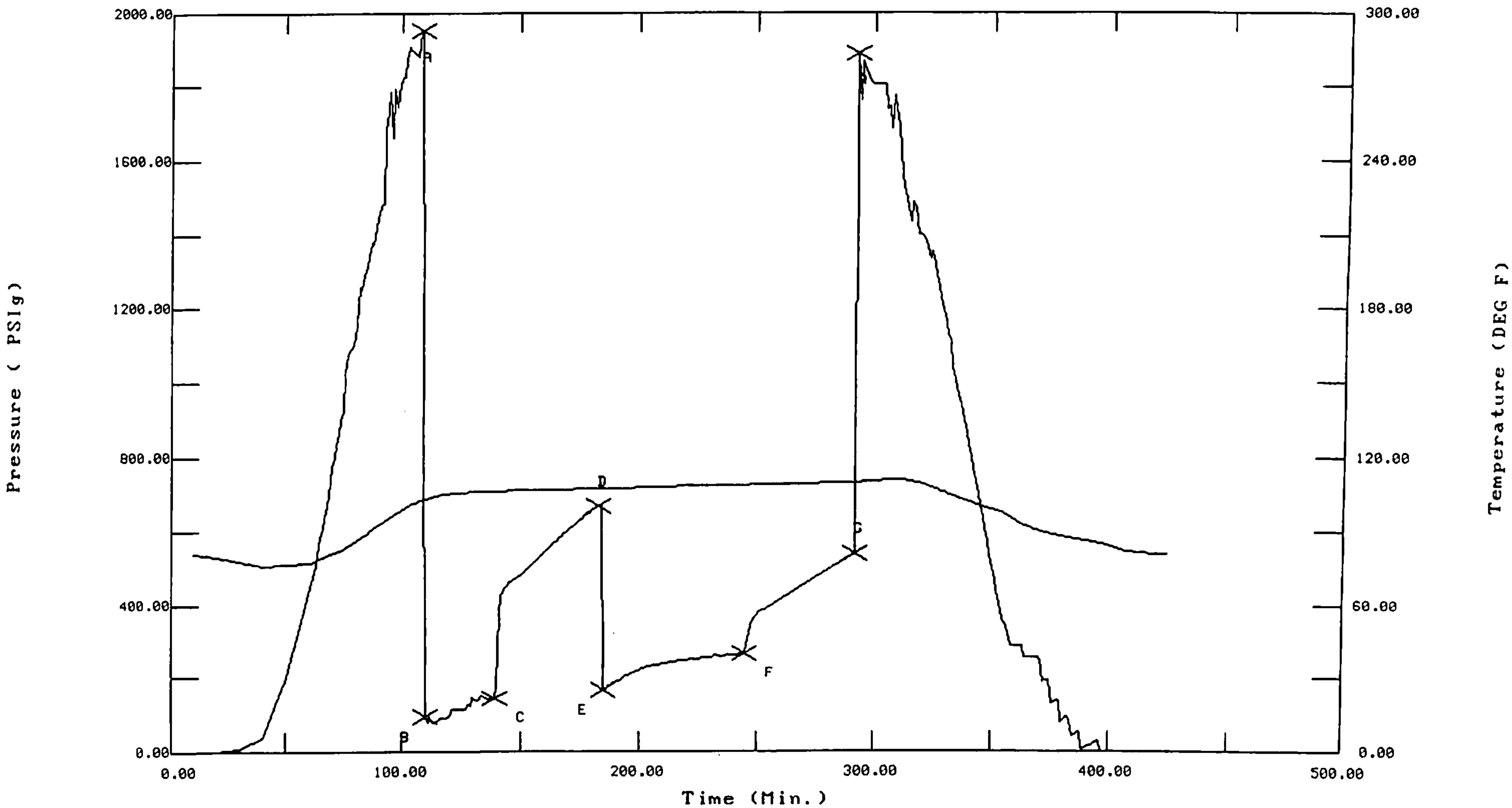


TEST HISTORY

test of washdown drilled in 1964 multiple zones

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1954.92
B:	0.00	88.79
C:	29.00	140.57
D:	44.00	668.22
E:	0.00	163.57
F:	60.00	264.45
G:	47.00	538.30
Q:	0.00	1887.36

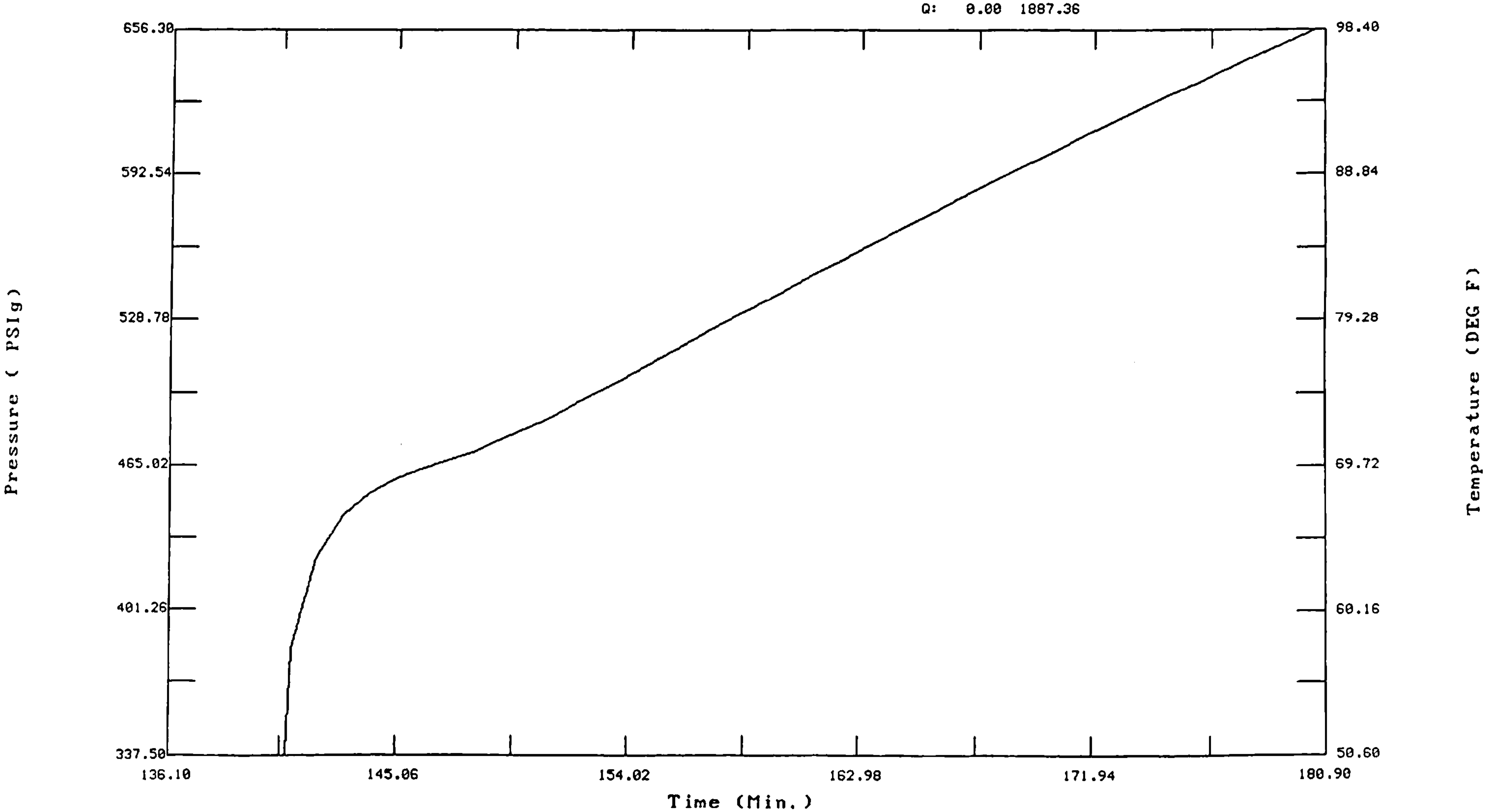


TEST HISTORY

test of washdown drilled in 1964 multiple zones Initial Shutin

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1954.92
B:	0.00	88.79
C:	29.00	140.57
D:	44.00	668.22
E:	0.00	163.57
F:	60.00	264.45
C:	47.00	538.30
Q:	0.00	1887.36

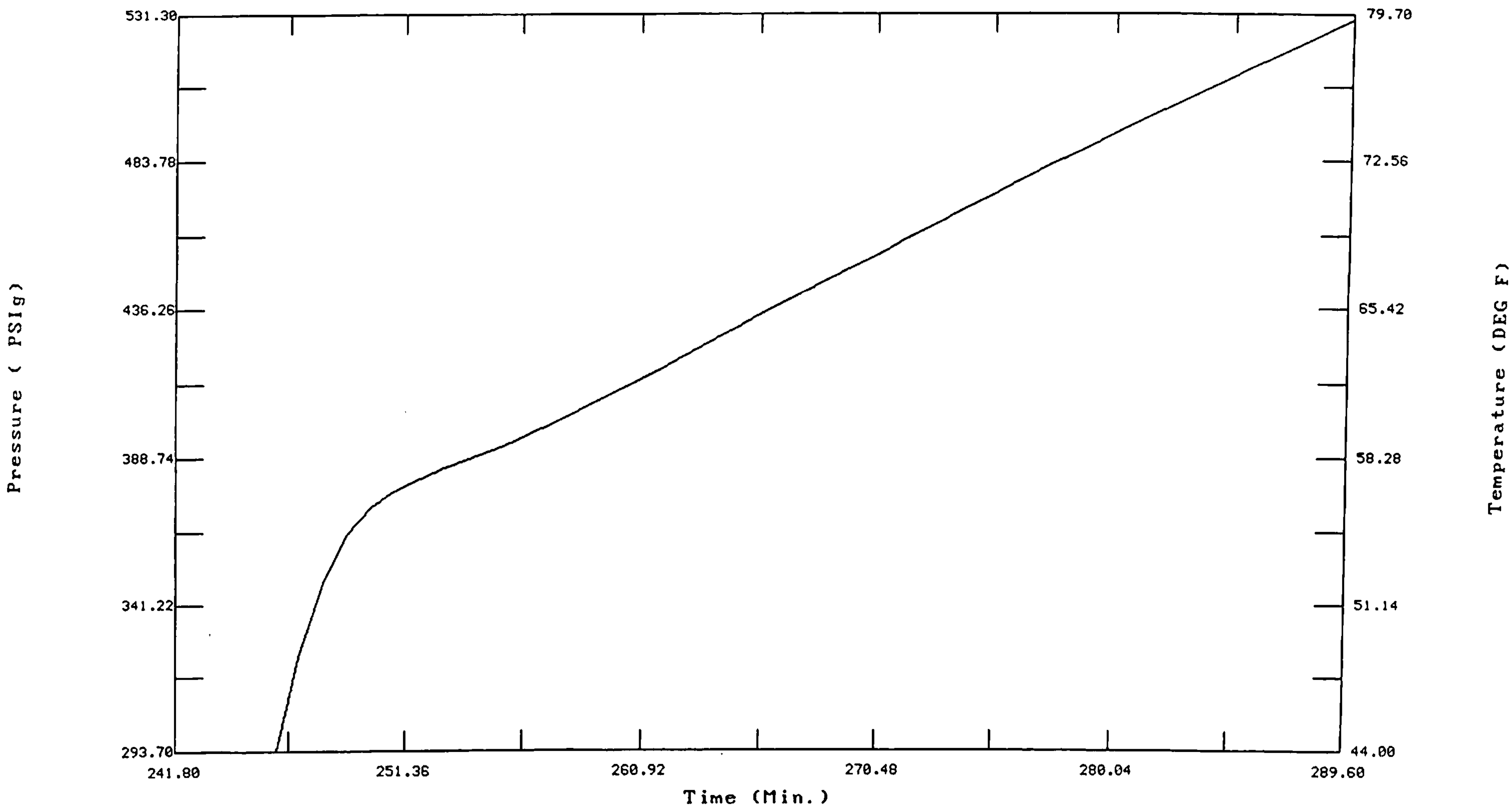


TEST HISTORY

test of washdown drilled in 1964 multiple zones Final Shutin

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1954.92
B:	0.00	88.79
C:	29.00	140.57
D:	44.00	668.22
E:	0.00	163.57
F:	60.00	264.45
G:	47.00	538.30
Q:	0.00	1887.36

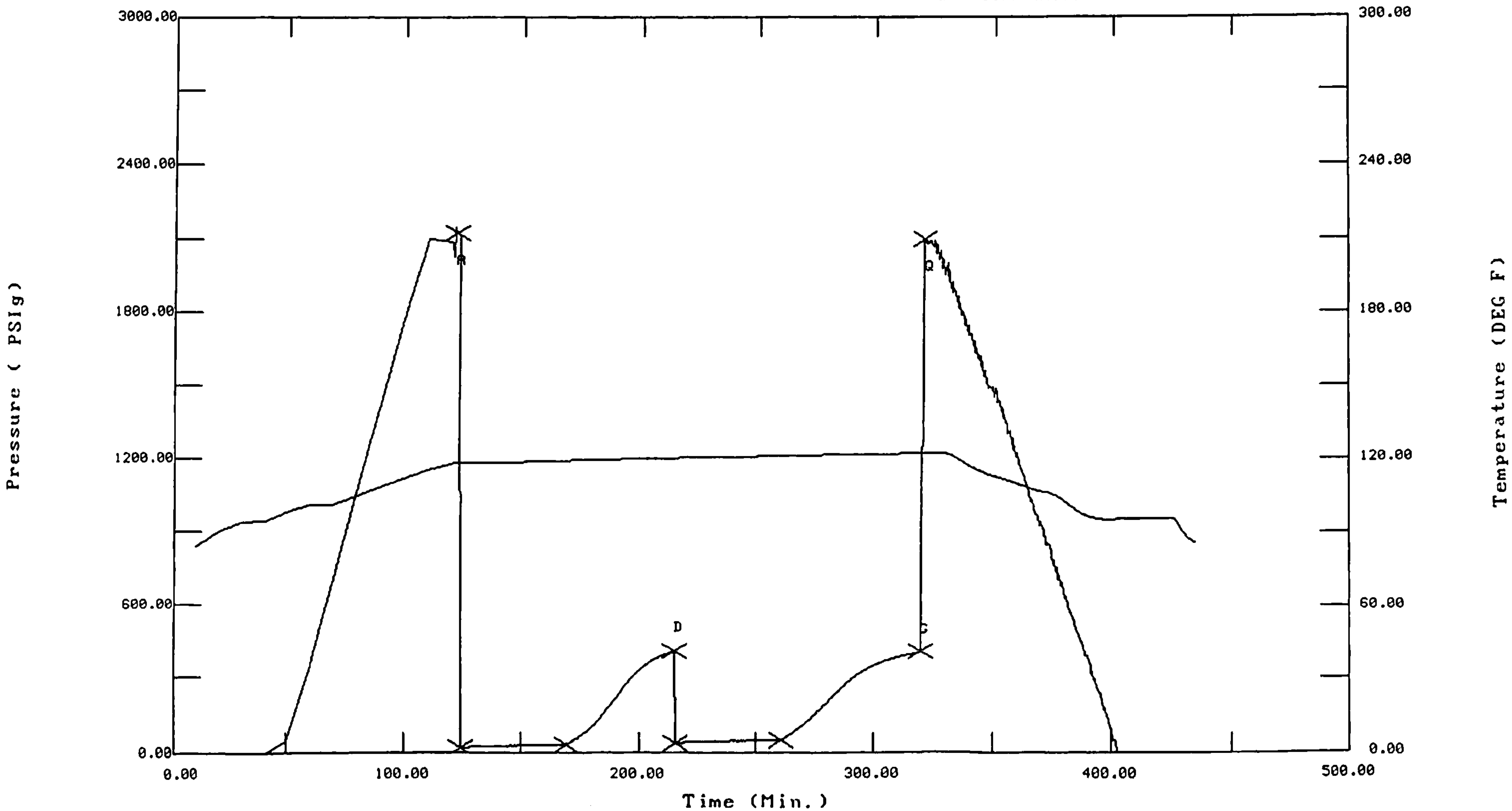


TEST HISTORY

depleted tight test

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2124.79
B:	0.00	12.83
C:	45.50	30.37
D:	45.50	406.96
E:	0.00	32.89
F:	45.50	45.56
G:	58.50	403.18
Q:	0.00	2099.61

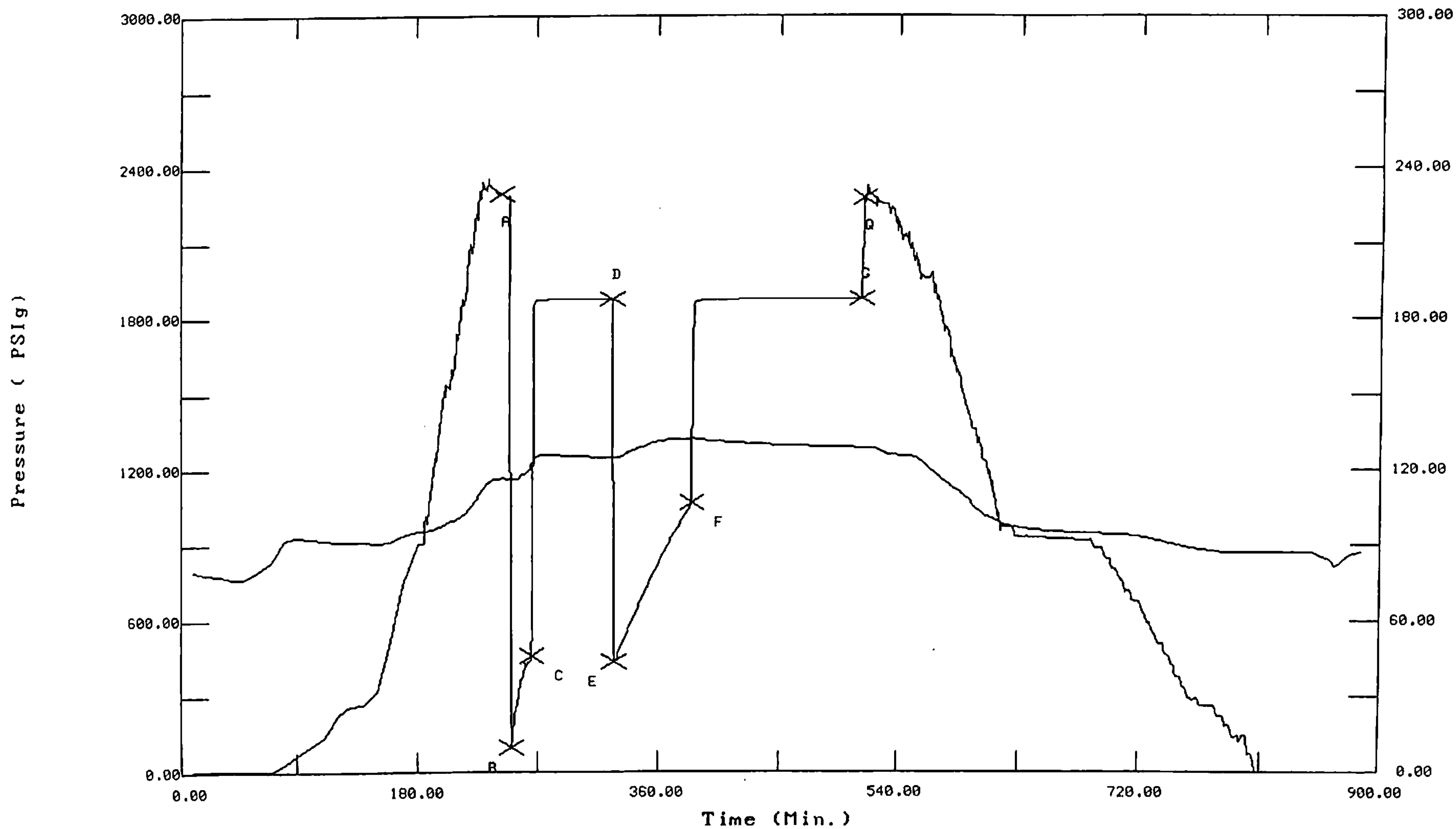


TEST HISTORY

Med perm high pressure water test with severe damage

Flag Points

	t(Min.)	P(PSIg)
A:	0.00	2300.62
B:	0.00	93.32
C:	15.00	459.58
D:	60.00	1878.44
E:	0.00	435.24
F:	59.00	1065.04
G:	126.00	1877.85
Q:	0.00	2282.74

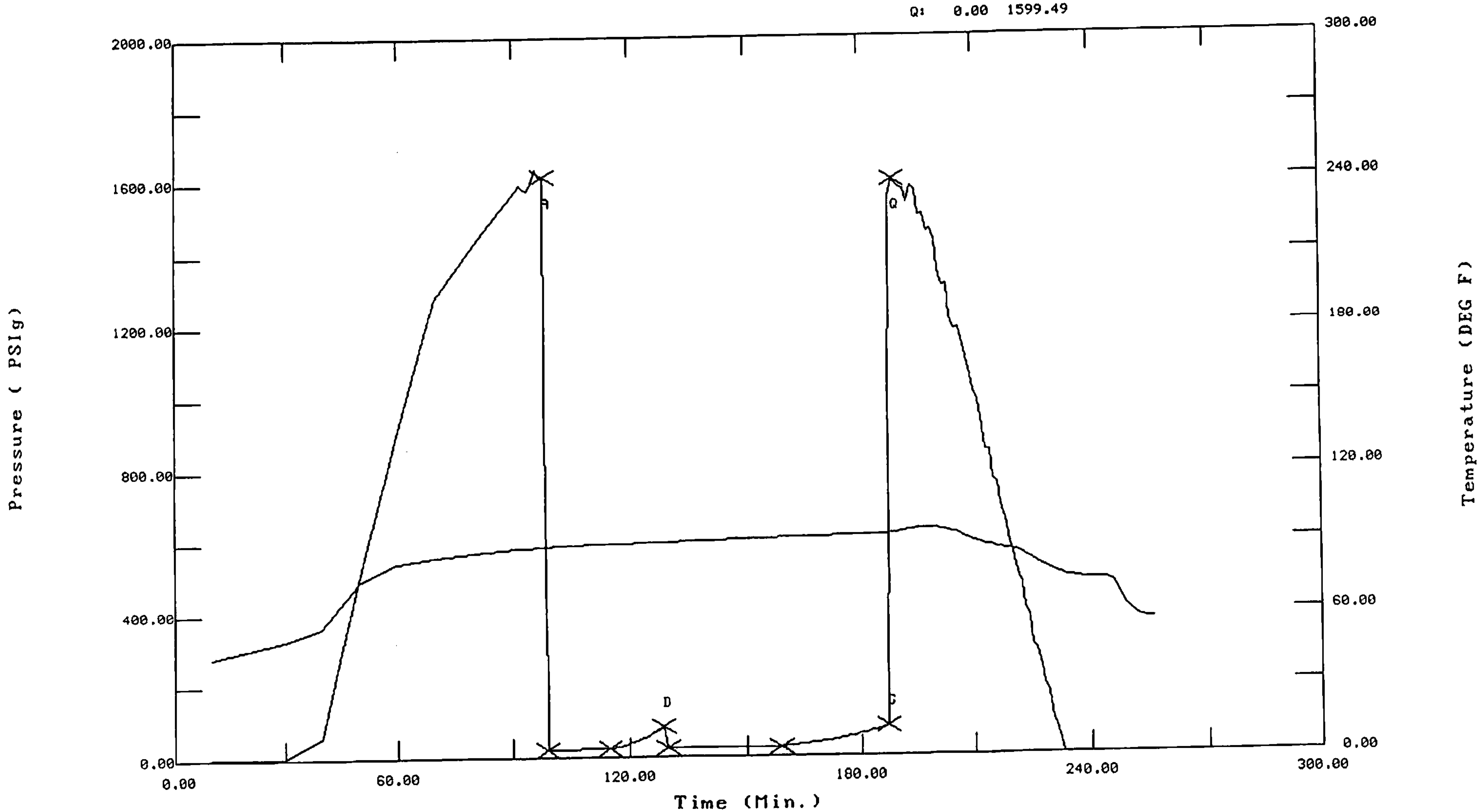


TEST HISTORY

Tight test

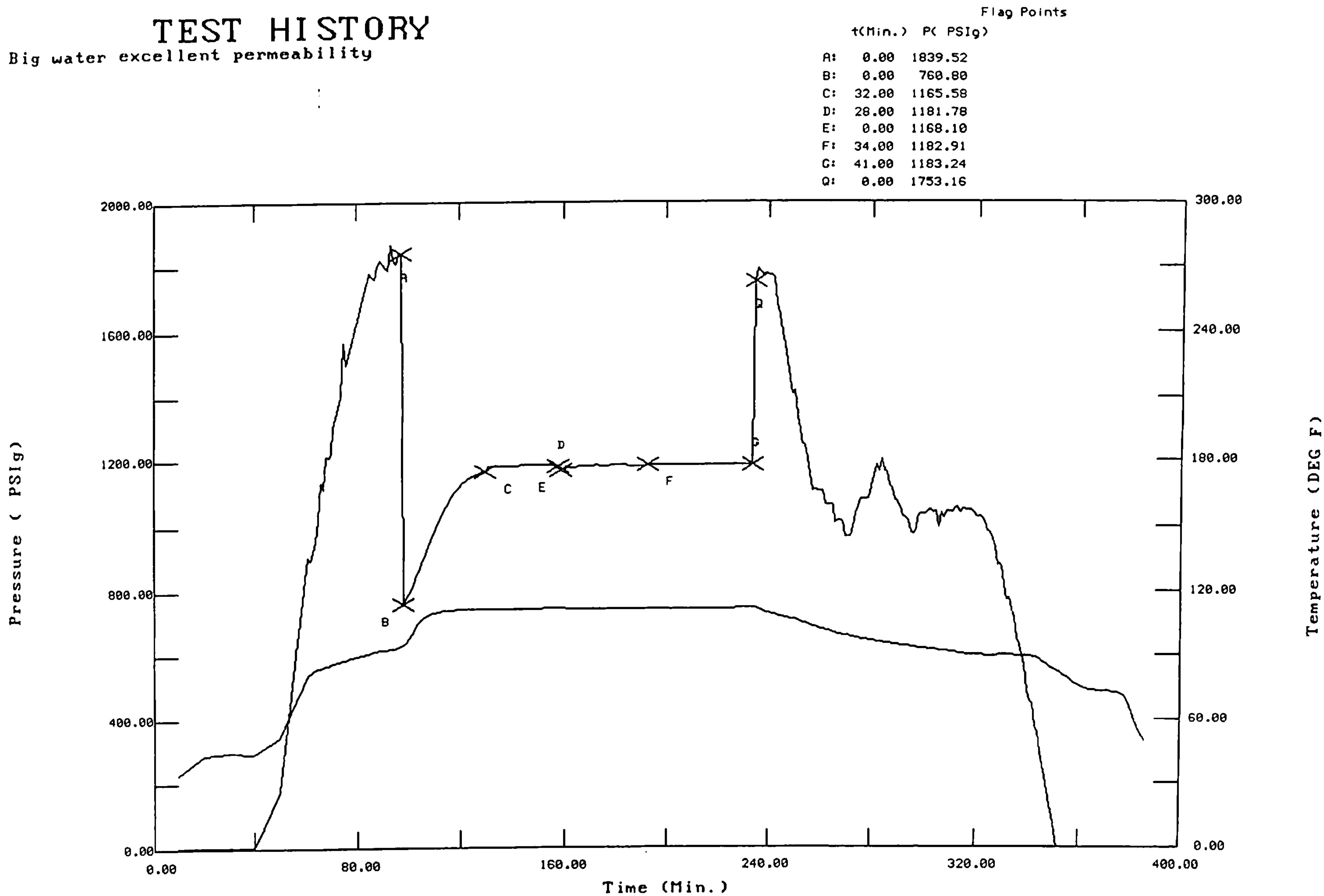
Flag Points

	t(Min.)	P(PSIg)
A:	0.00	1614.59
B:	0.00	18.88
C:	16.00	20.89
D:	14.00	81.82
E:	0.00	20.81
F:	29.00	23.07
G:	28.00	78.63
Q:	0.00	1599.49



TEST HISTORY

Big water excellent permeability

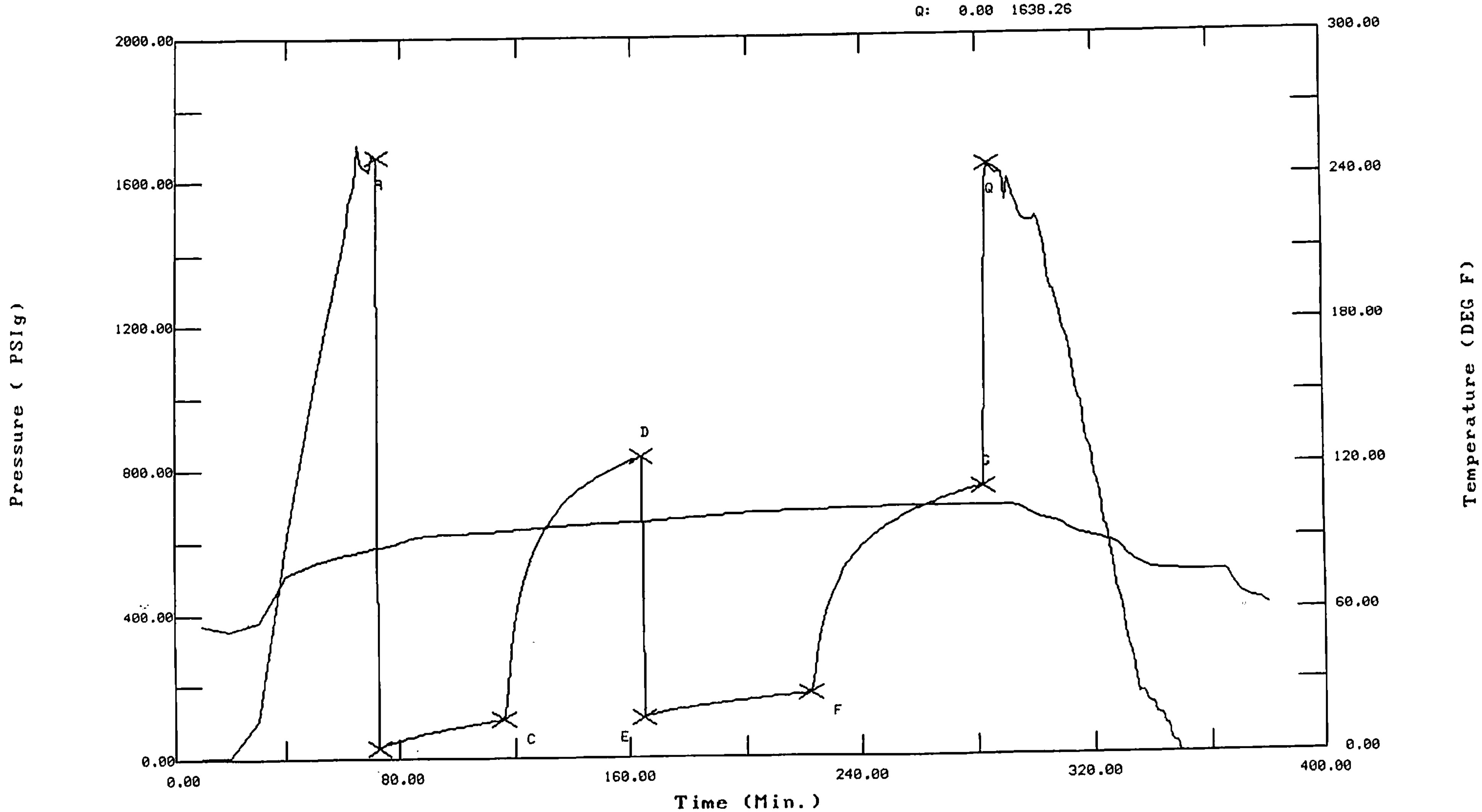


TEST HISTORY

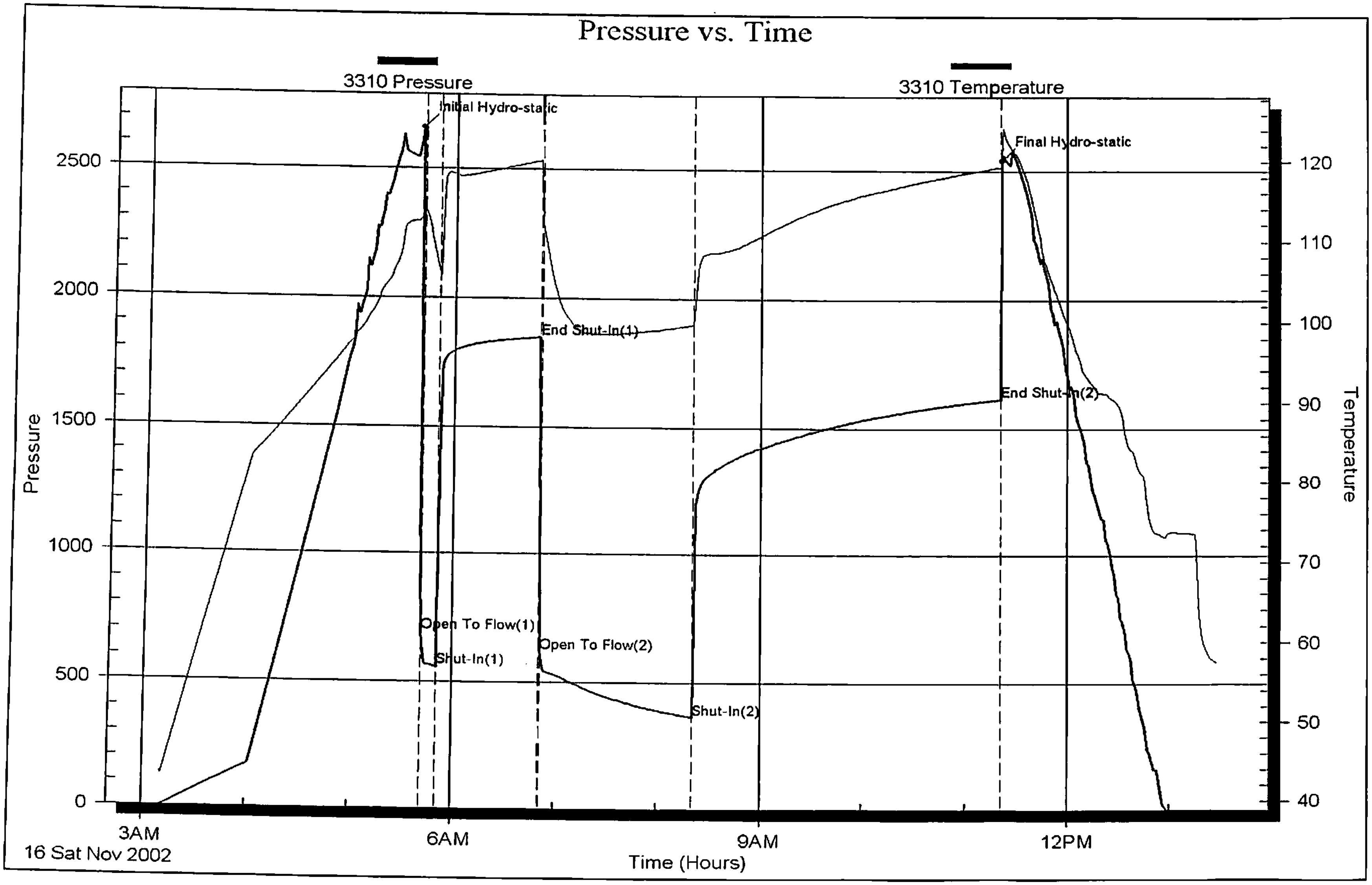
med buildup

Flag Points

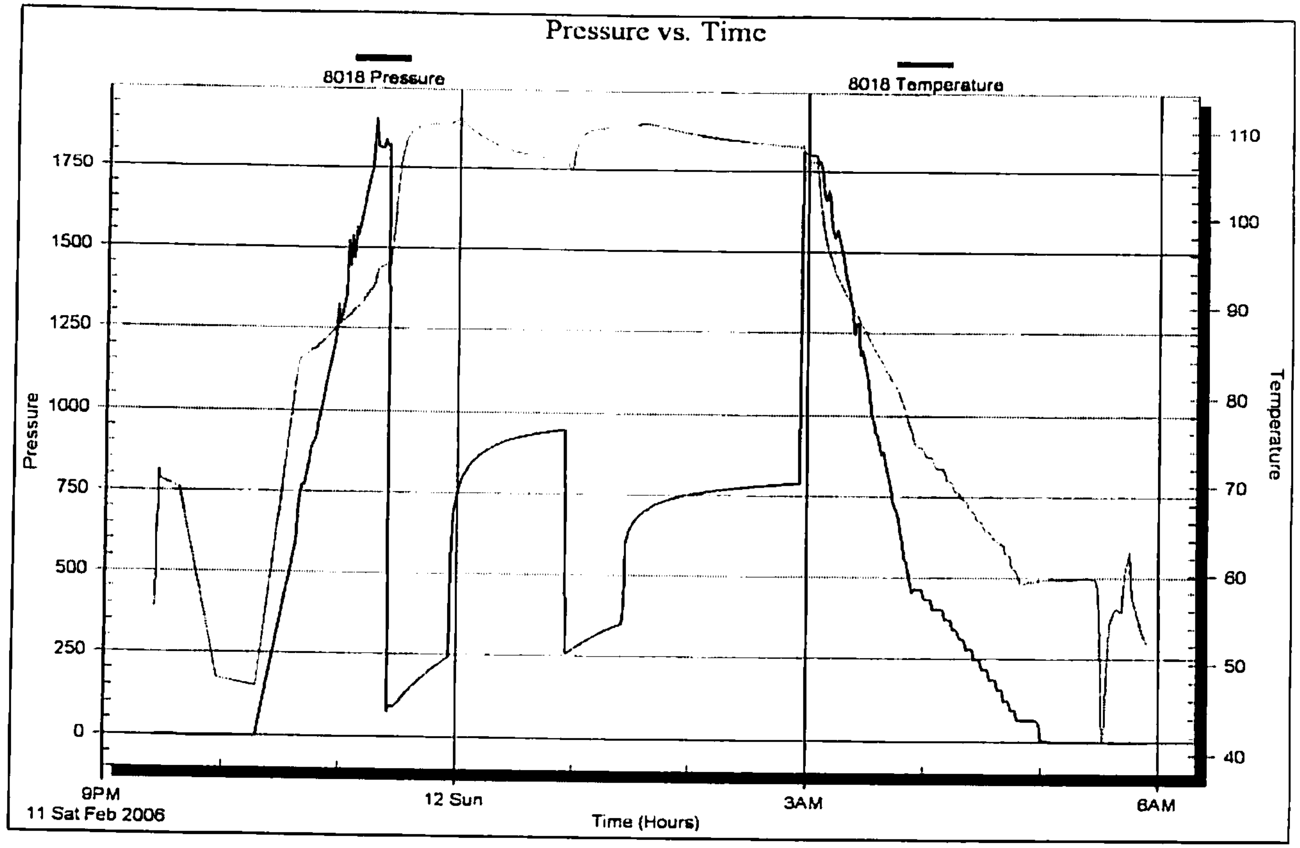
	t(Min.)	P(PSIg)
A:	0.00	1668.14
B:	0.00	27.02
C:	43.00	101.38
D:	48.00	835.83
E:	0.00	107.17
F:	57.00	169.19
G:	60.00	745.10
Q:	0.00	1638.26



Serial #: 3310 Inside Lario Oil & Gas 11 33s 19w DST Test Number: 2



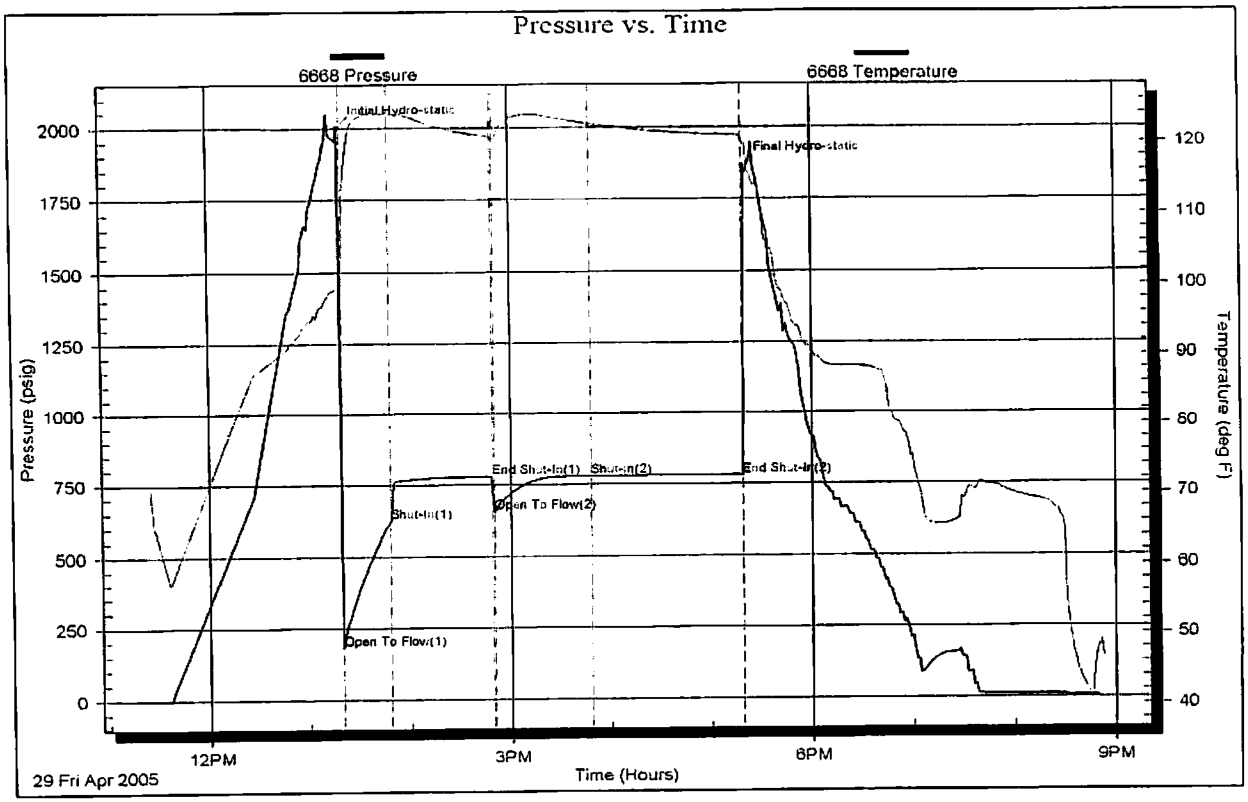
Serial #: 8018 Inside DST Test Number: 4



Limited Reservoir

Serial #: 6668 Inside

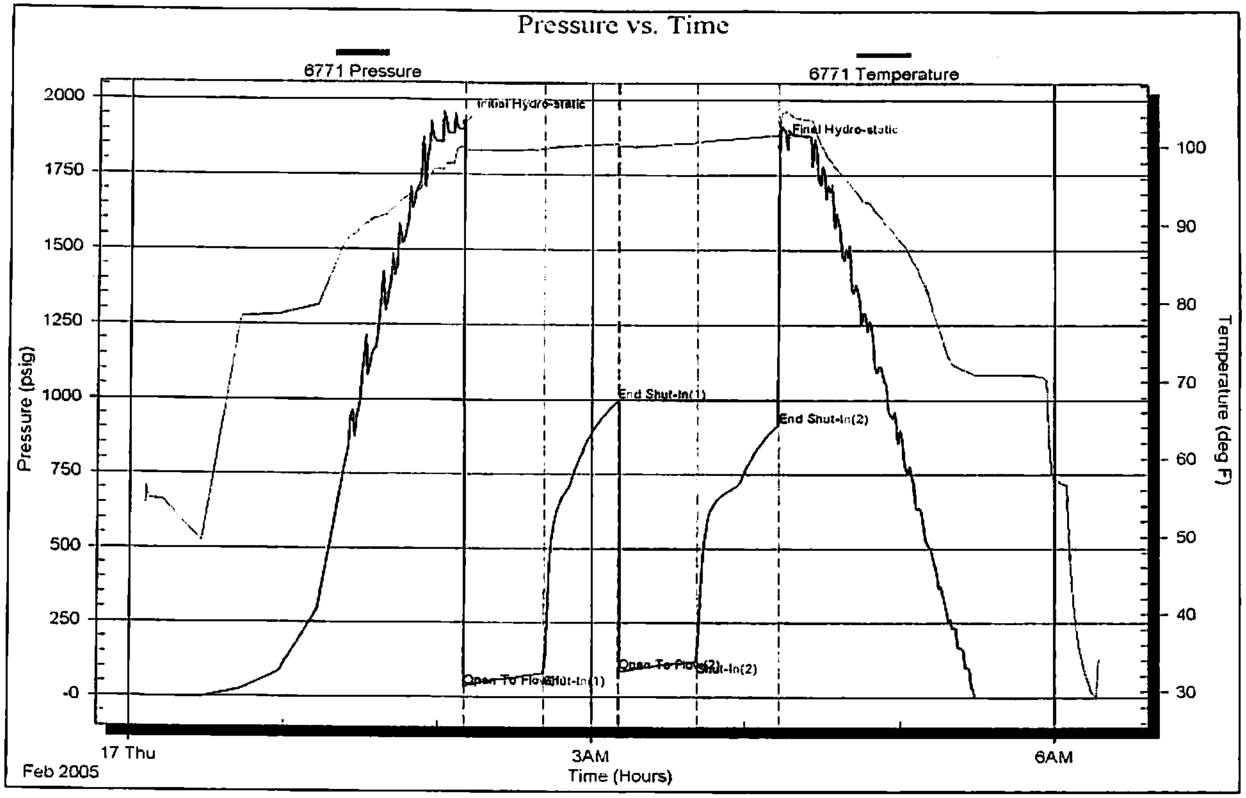
DST Test Number: 4



Trilobite Testing, Inc Ref. No: 20701 Printed: 2006.02.27 @ 16:10:49 Page 1

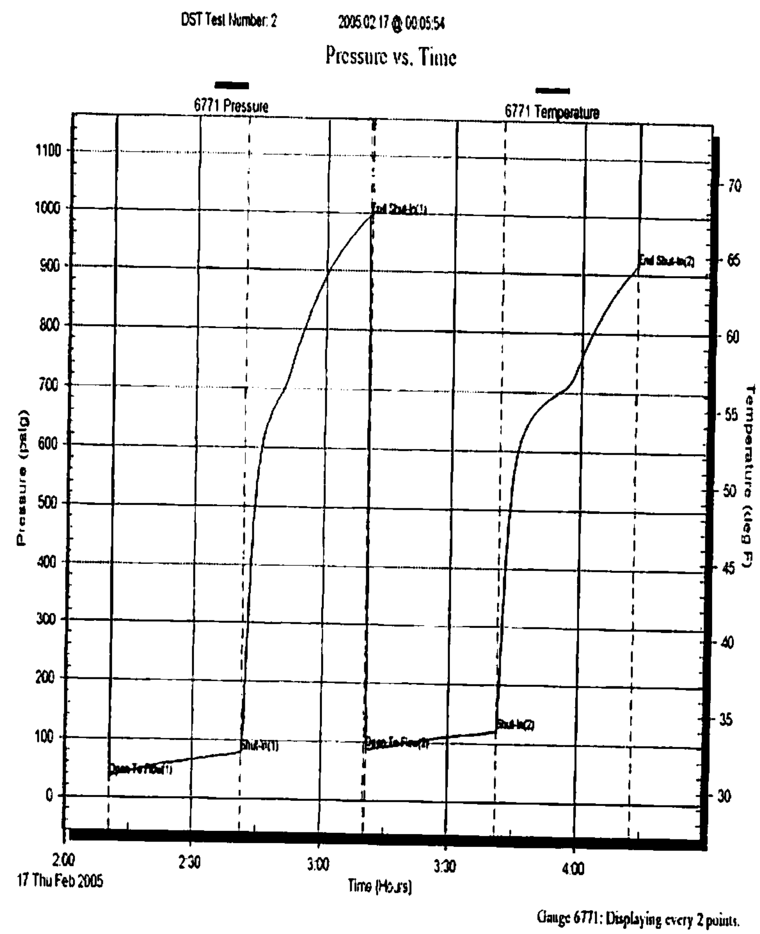
Flow Stabilized during final flow

Serial #: 6771 Inside DST Test Number: 2



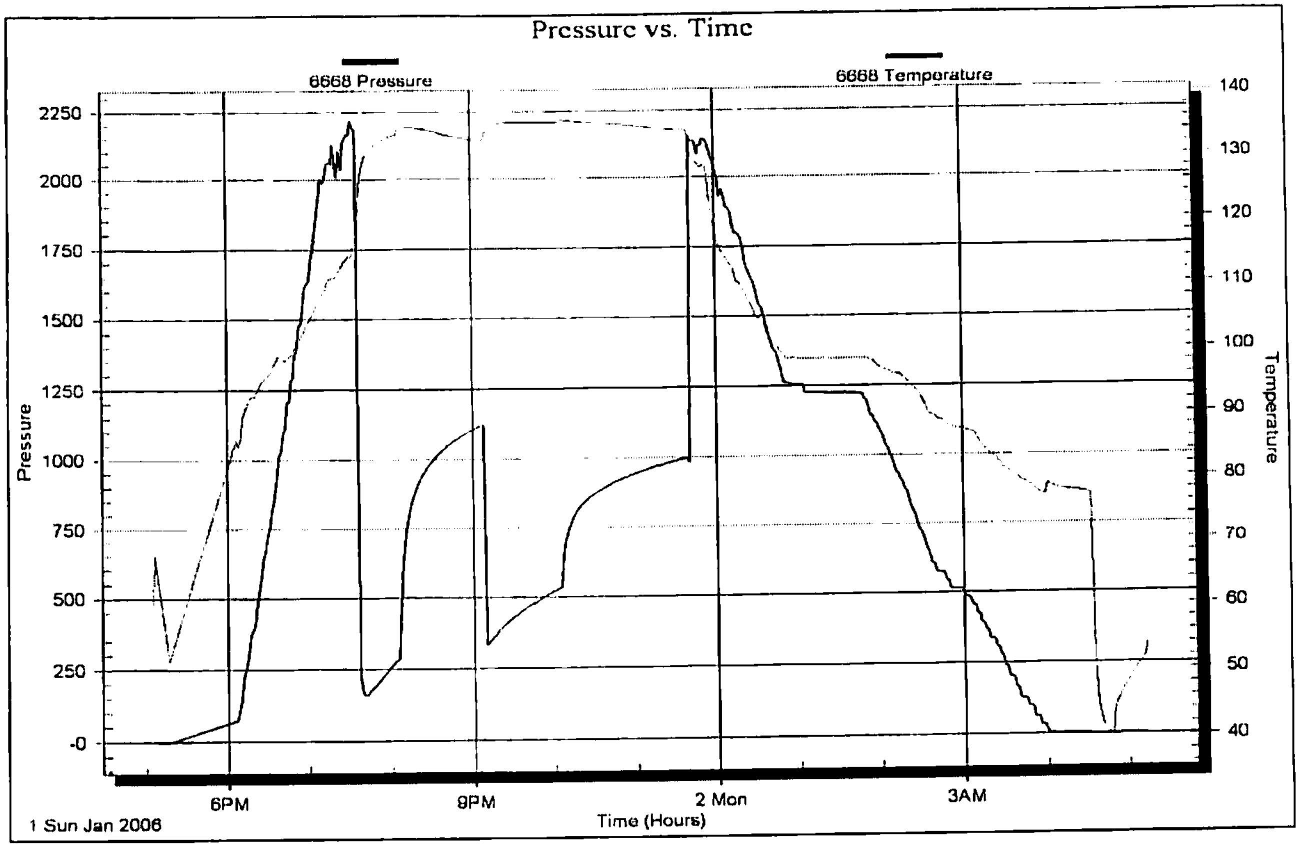
Trilobite Testing, Inc Ref. No: 20485 Printed: 2006.02.27 @ 16:21:00 Page 1

Two Zones


DST Test Number: 2
2005.02.17 @ 00:05:54
Pressure vs. Time
6771 Pressure
6771 Temperature
Pressure (psig)
Temperature (deg F)
1100
1000
900
800
700
600
500
400
300
200
100
0
70
65
60
55
50
45
40
35
30
End Shut-In(1)
End Shut-In(2)
Shut-In(1)
Shut-In(2)
Open-To-Flow(1)
Open-To-Flow(2)
2:00
17 Thu Feb 2005
2:30
3:00
3:30
4:00
Time (Hours)
Gauge 6771: Displaying every 2 points.

Two Zones

Serial #: 6668 Inside DST Test Number: 2

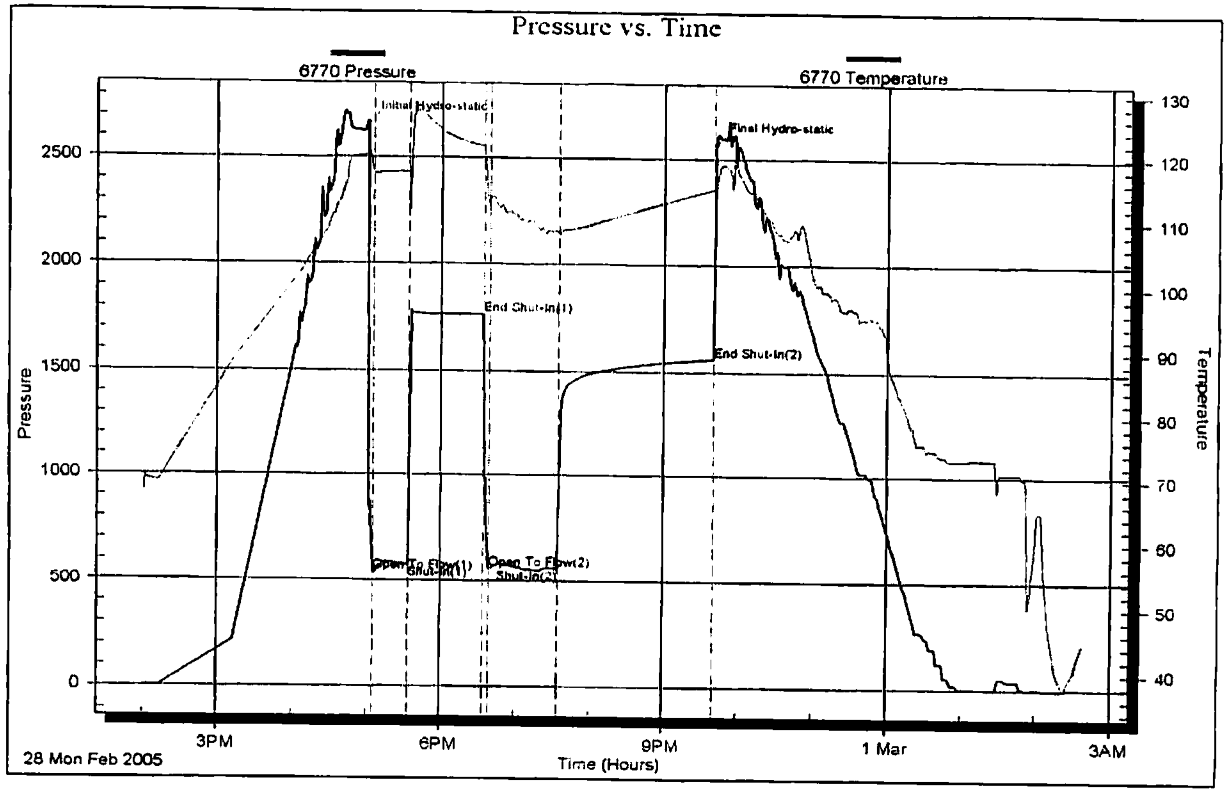


Trilobite Testing, Inc Ref. No 21946 Printed: 2006.02.27 @ 11:33:28 Page 2

Barrier Within Radius of Investigation

Serial #: 6770 Inside

DST Test Number: 2

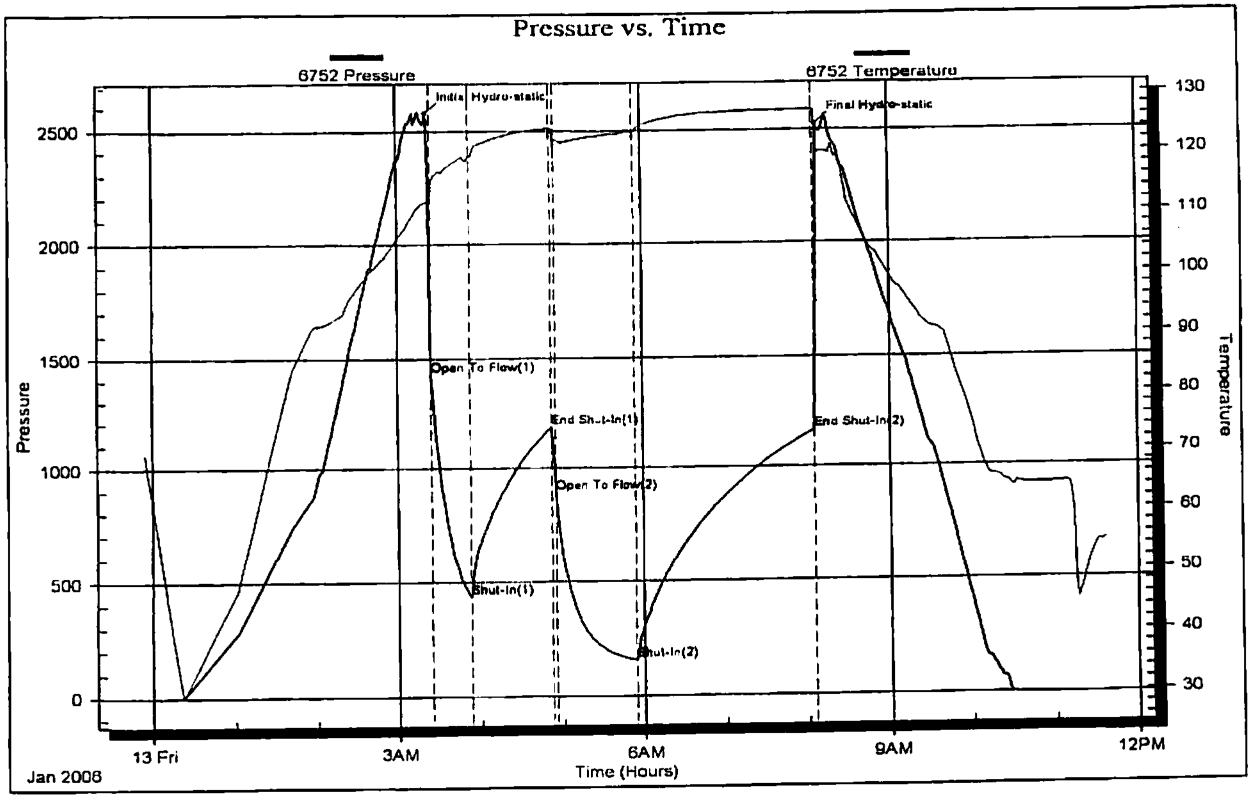


Trilobite Testing, Inc   Ref. No: 21779   Printed: 2006.02.27 @ 16:18:55   Page 1

Gas Test Damaged removed

Serial #: 6752 Inside

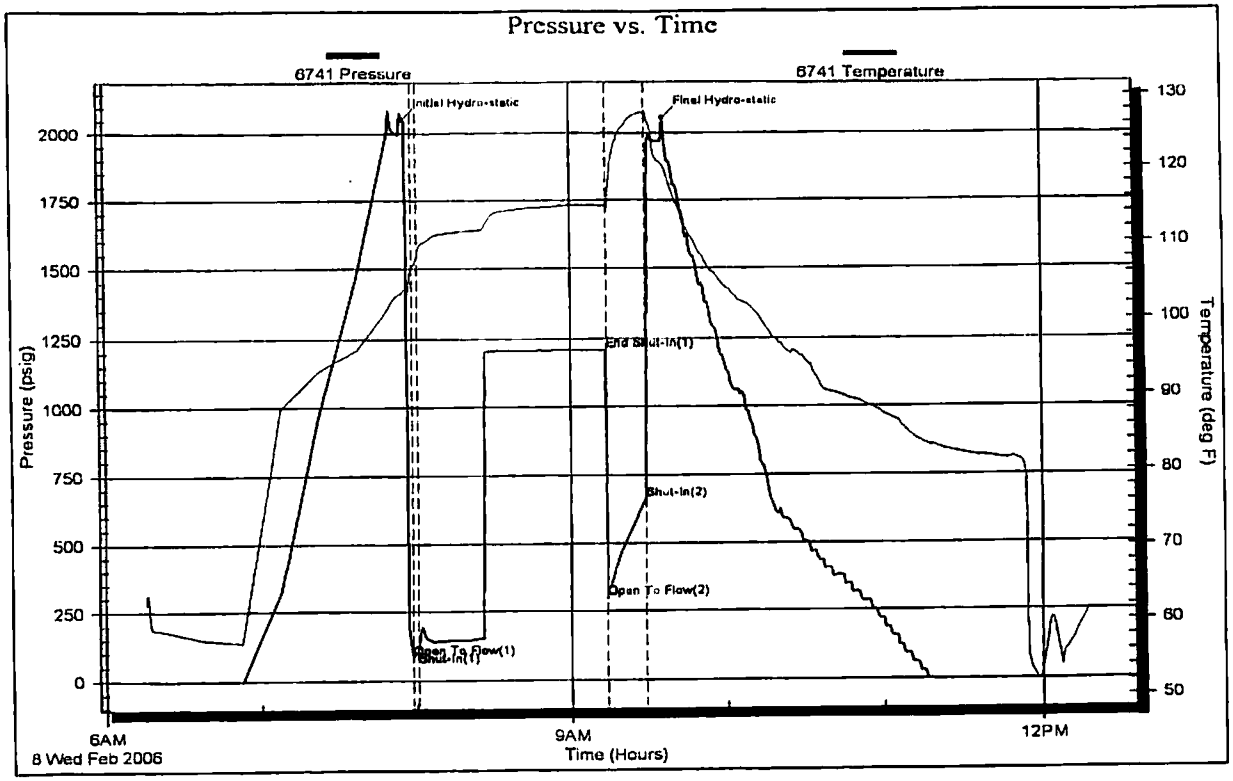
DST Test Number: '



Trilobite Testing, Inc Ref. No: 22280 Printed: 2006.02.10 @ 11:21:36 Page 1

Depleting Gas Test

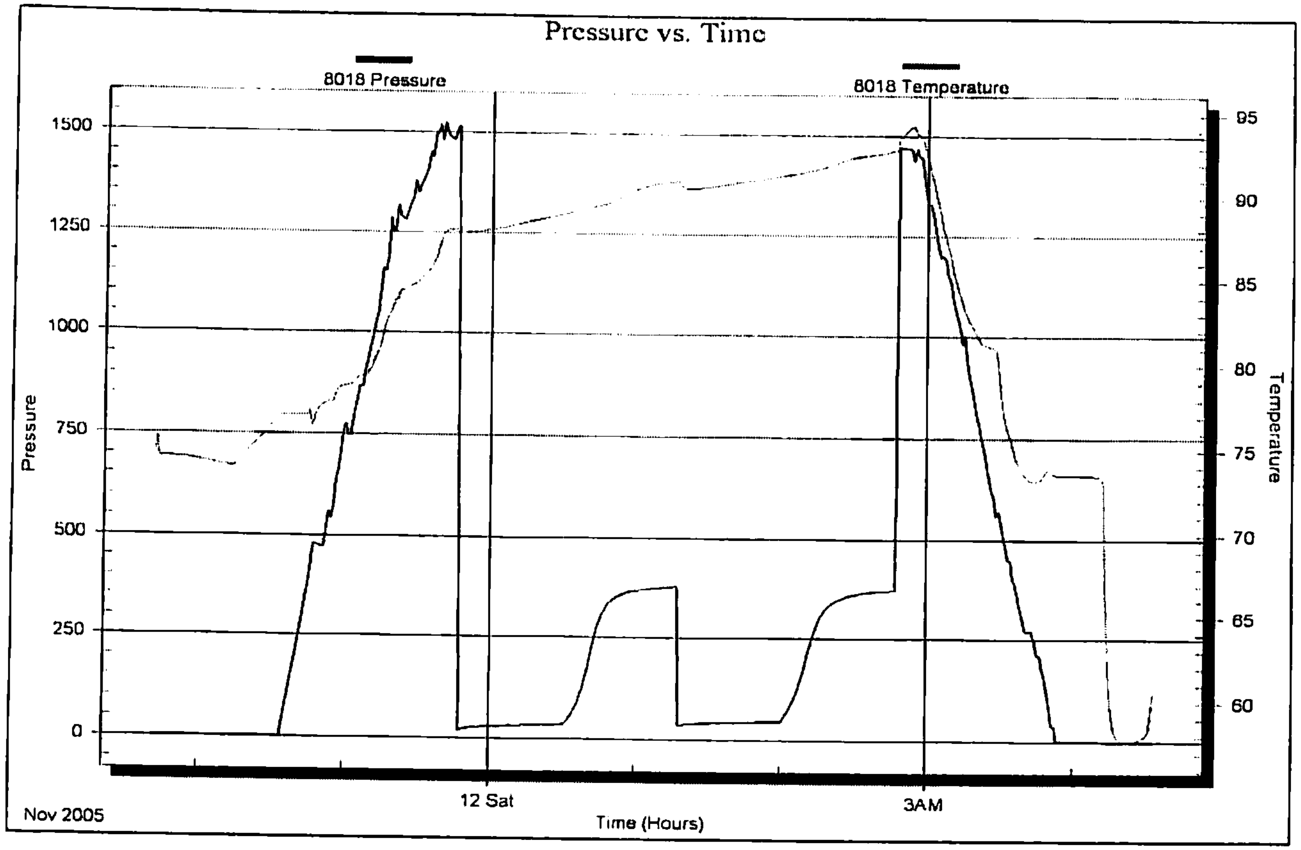
Serial #: 6741 Inside DST Test Number.



Trilobite Testing, Inc Ref. No: 23901 Printed: 2006.02.10 @ 11:20:28 Page 1

Well cleaned up during final flow

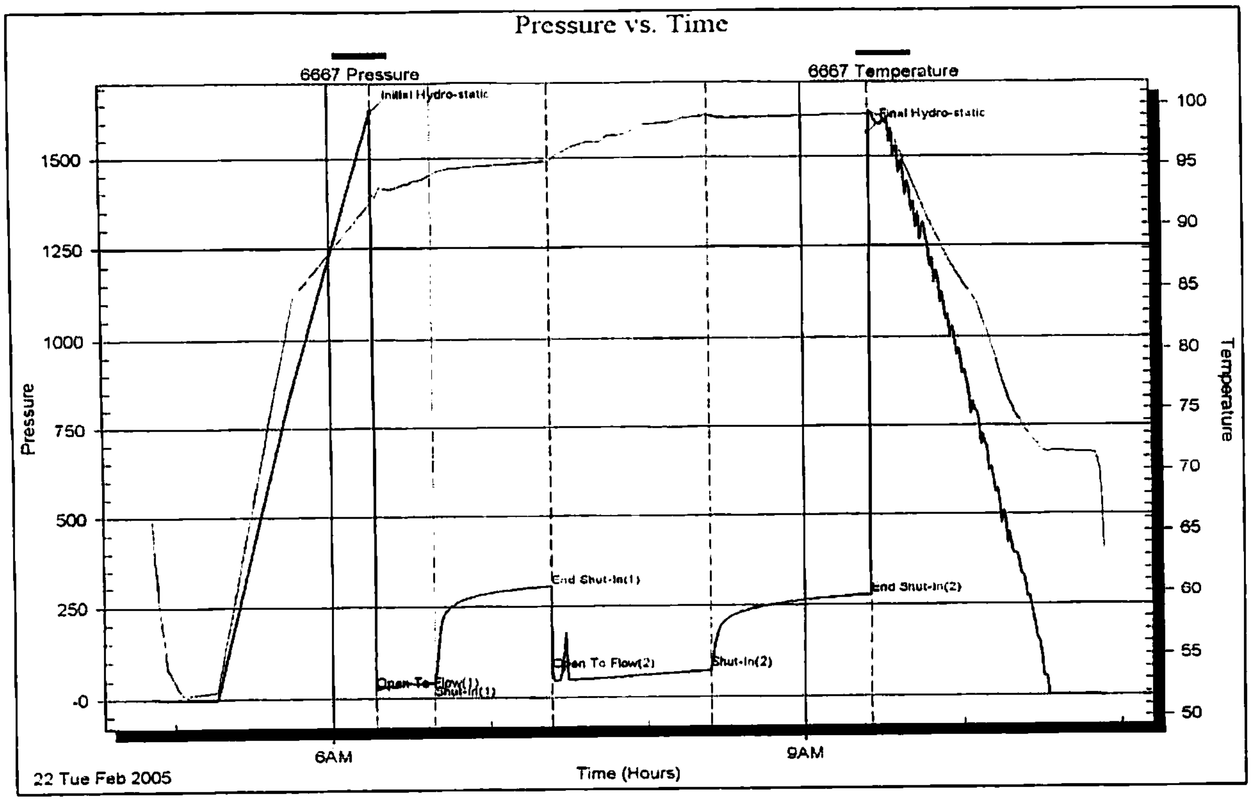
Serial #: 8018 Inside DST Test Number: 1



Trilobite Testing, Inc Ref. No: 23483 Printed: 2006.02.27 @ 11:35:09 Page 2

Depleted Pressures

Serial #: 6667 Inside DST Test Number: 3

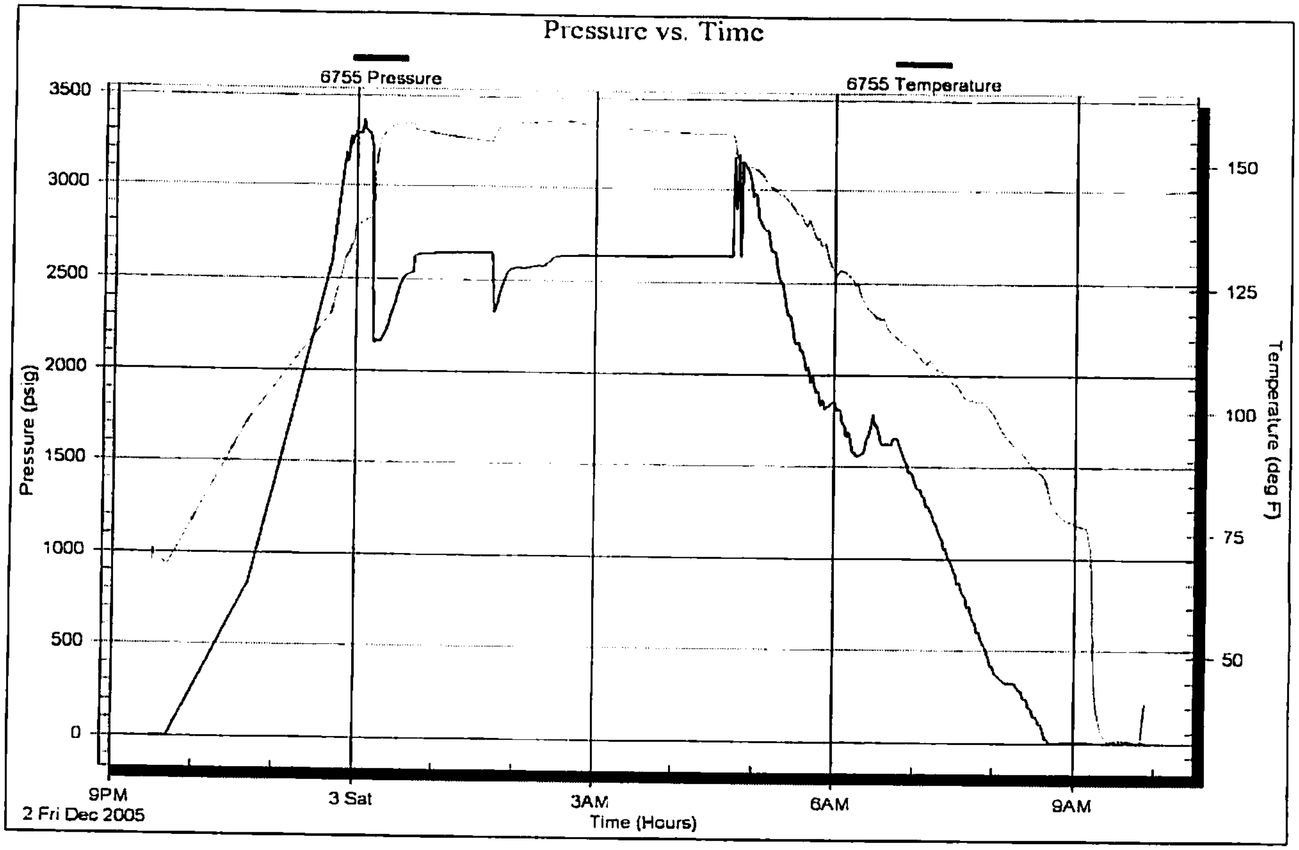


Trilobite Testing, Inc Ref. No: 19974 Printed: 2006.02.27 @ 16:15:56 Page 1

Depleted Pressures

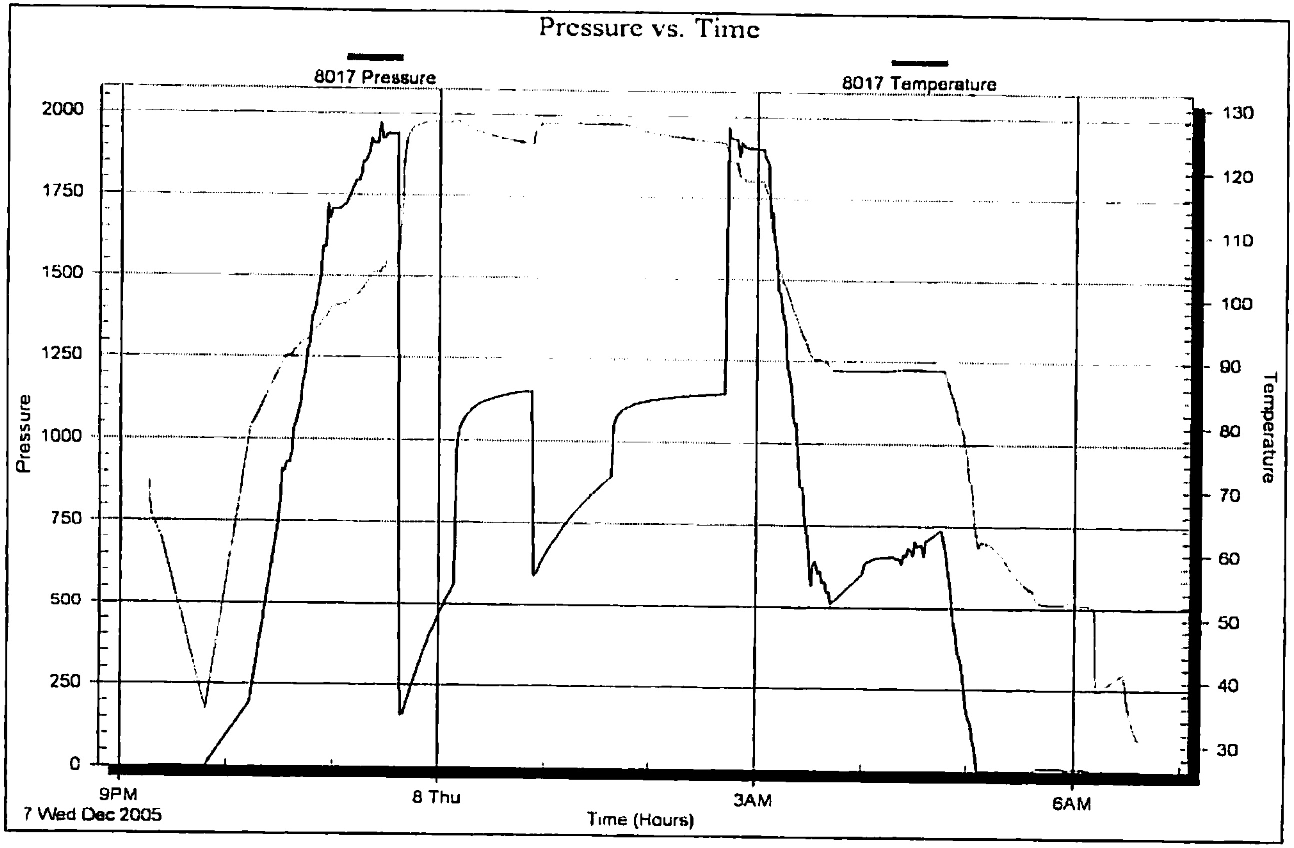
Serial #: 6755 Inside

DST Test Number: 1



Excellent Permeability

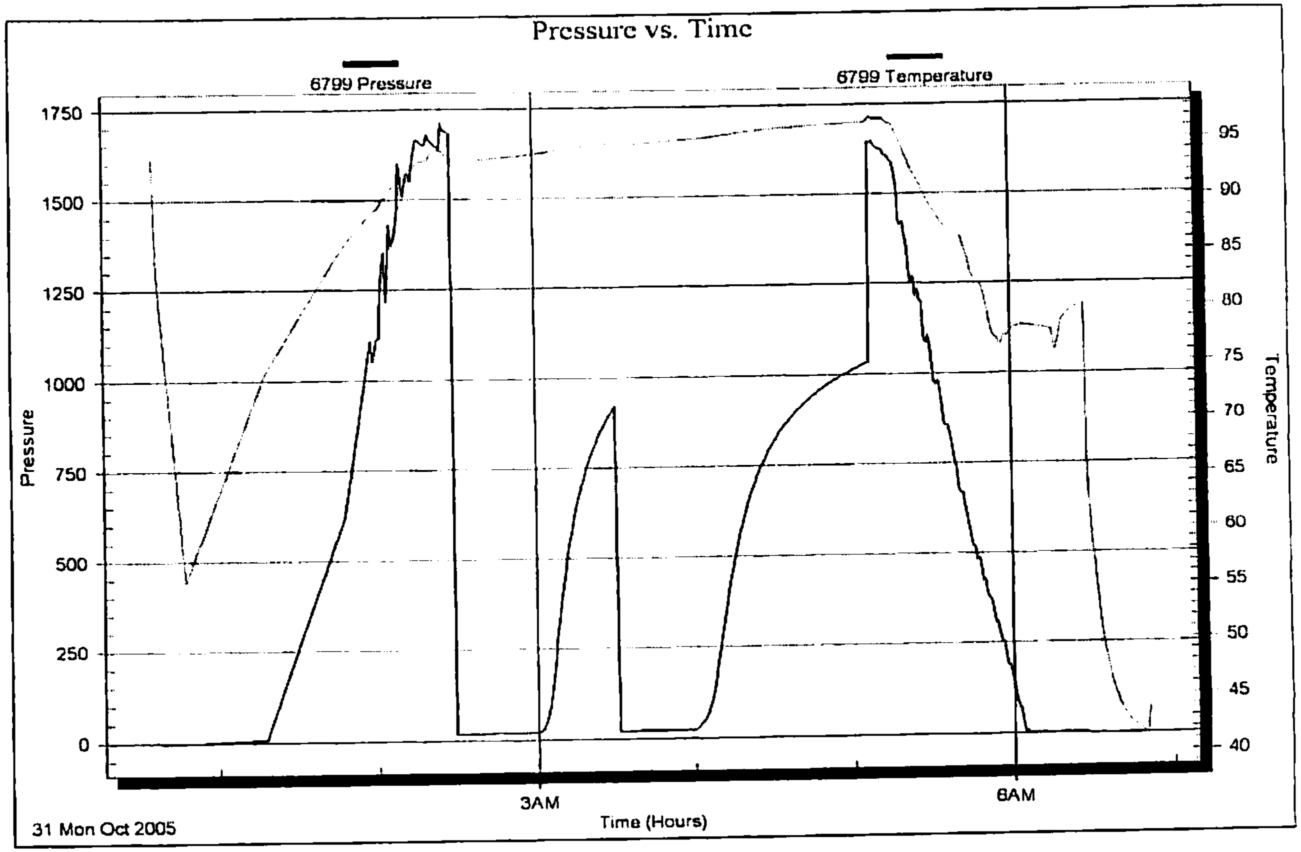
Serial #: 8017 Inside DST Test Number: 1



Good Permeability

Serial #: 6799 Inside

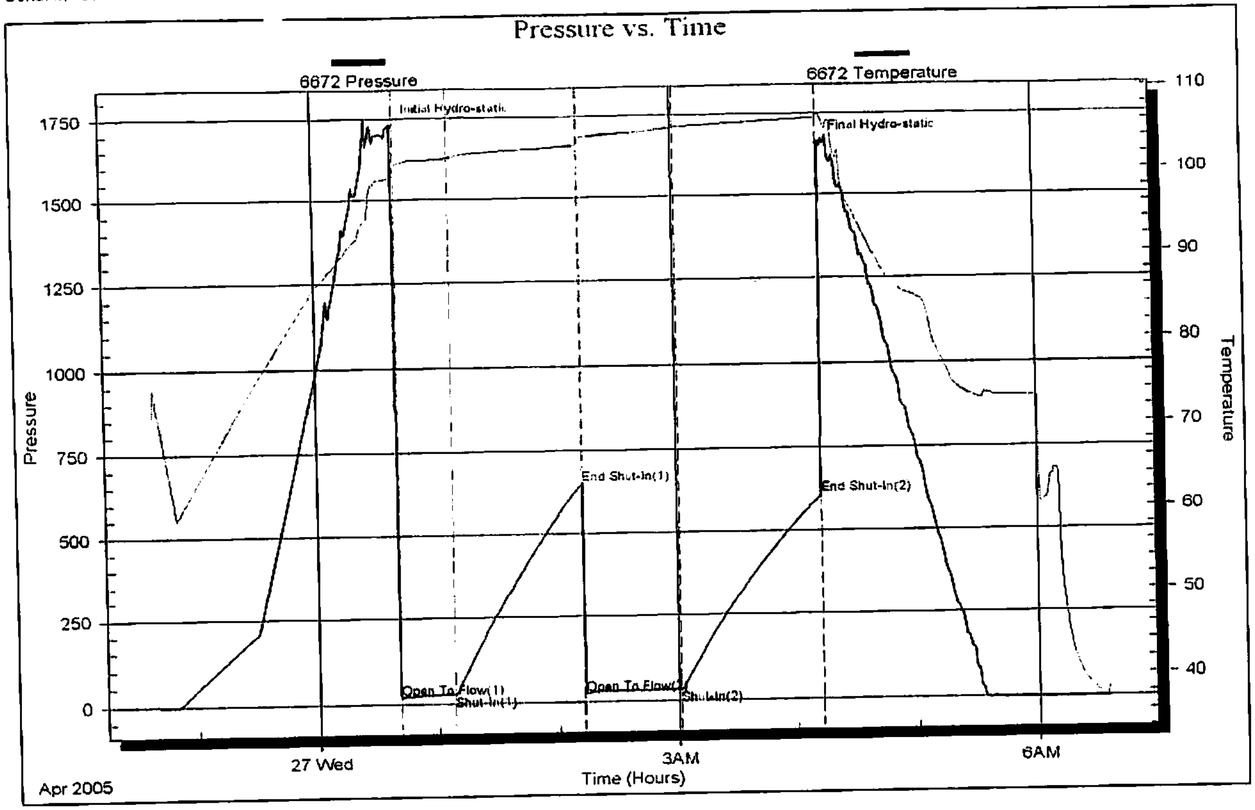
DST Test Number: 4



Low Permeability

Serial #: 6672 Inside

DST Test Number: 2

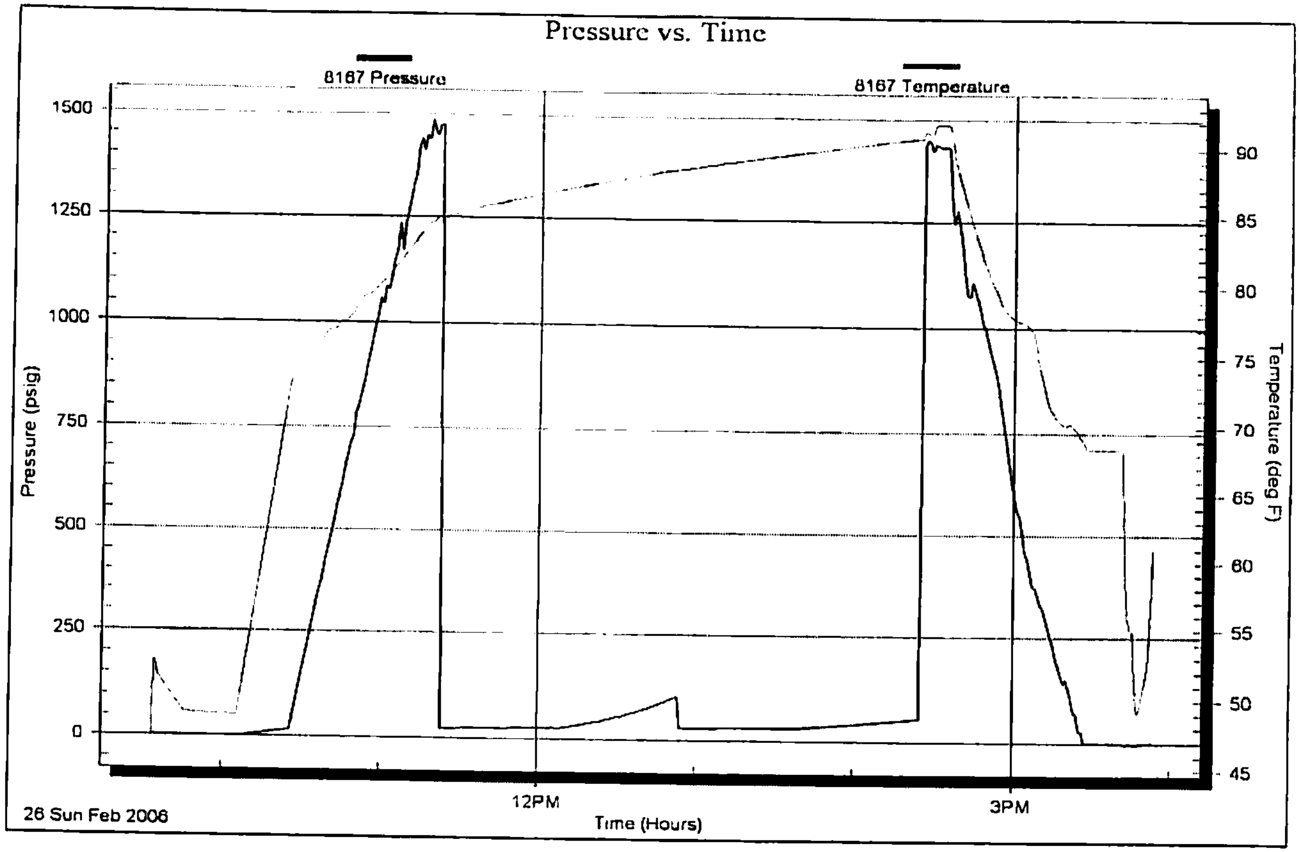


Trilobite Testing, Inc Ref. No: 19999 Printed: 2006.02.27 @ 16:11:20 Page 1

Low Permeability

Serial #: 8167 Inside

DST Test Number: 3

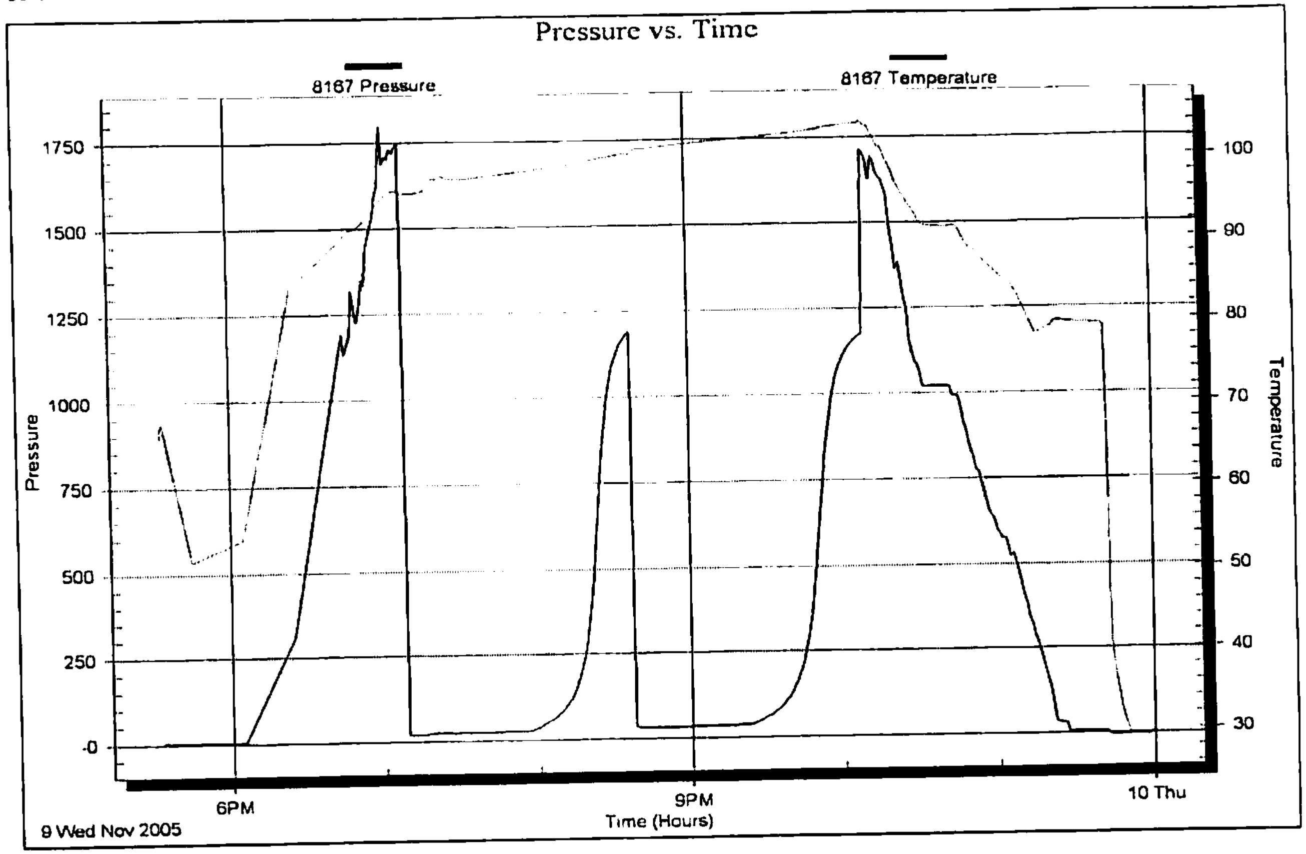


Trilobite Testing, Inc Ref No 23036 Printed: 2006.02.27 @ 11:45:52 Page 2

No Permeability

Serial #: 8167 Inside

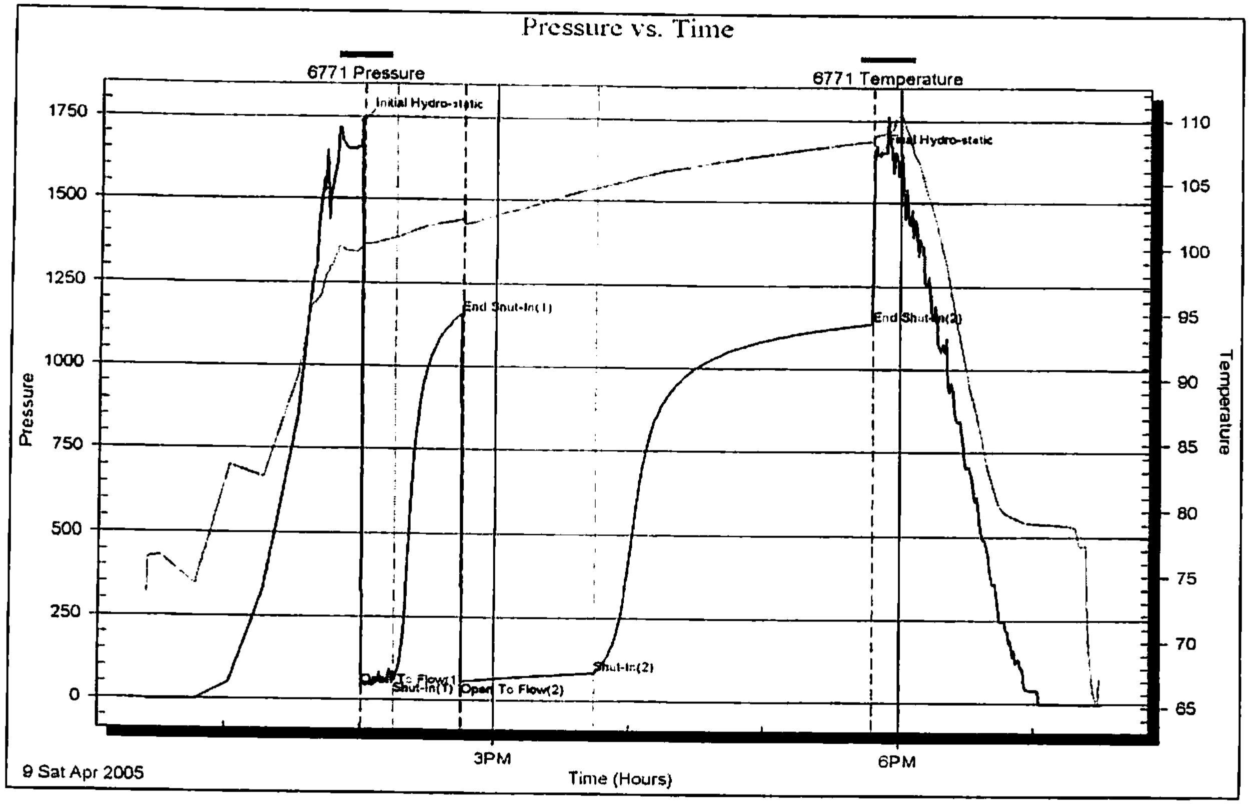
DST Test Number: 5



S Curve

Serial #: 6771 Inside

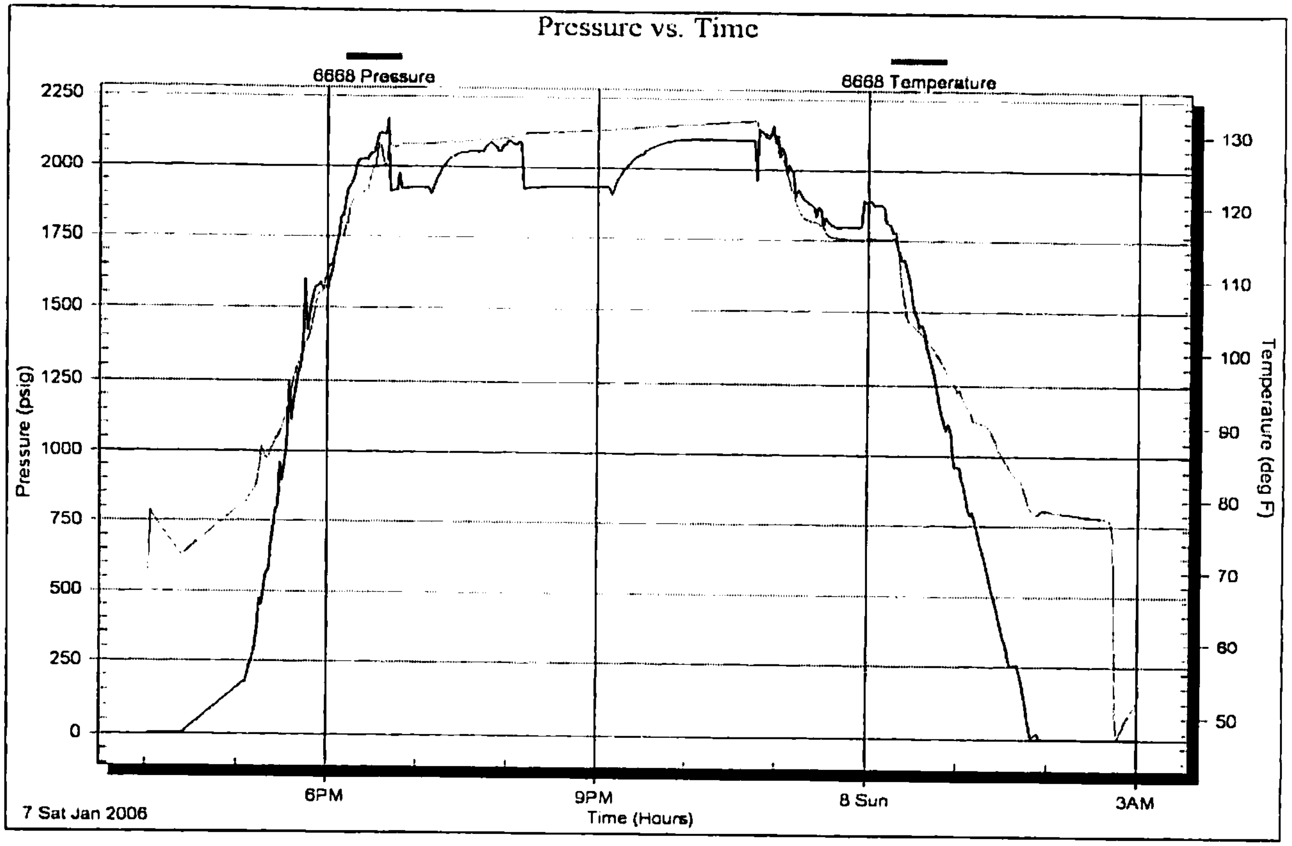
DST Test Number: 2



Trilobite Testing, Inc Ref. No: 21584 Printed: 2006.02 27 @ 16:05:55 Page 1

S Curve on shut in

Serial #: 6668 Inside DST Test Number: 1

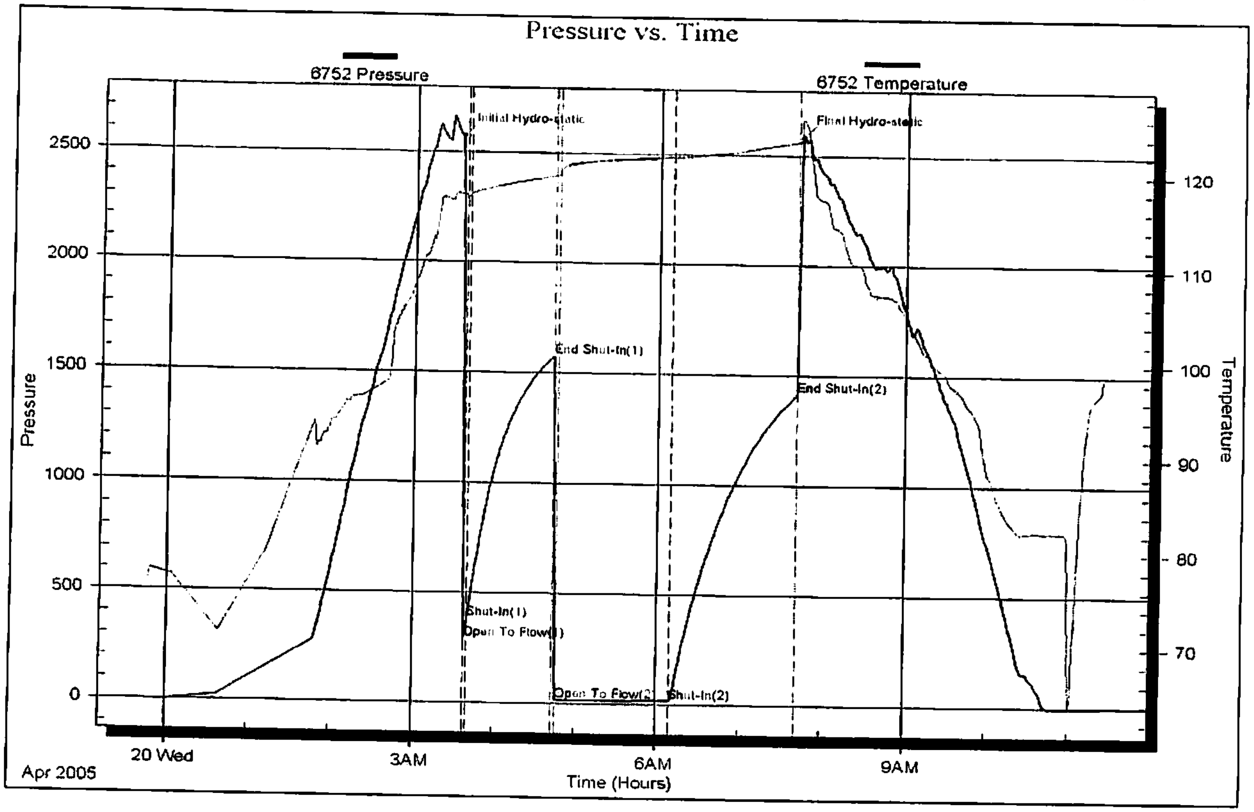


Trilobite Testing, Inc Ref No: 21948 Printed: 2006.02.27 @ 10:50:09 Page 2

Hole in Pipe

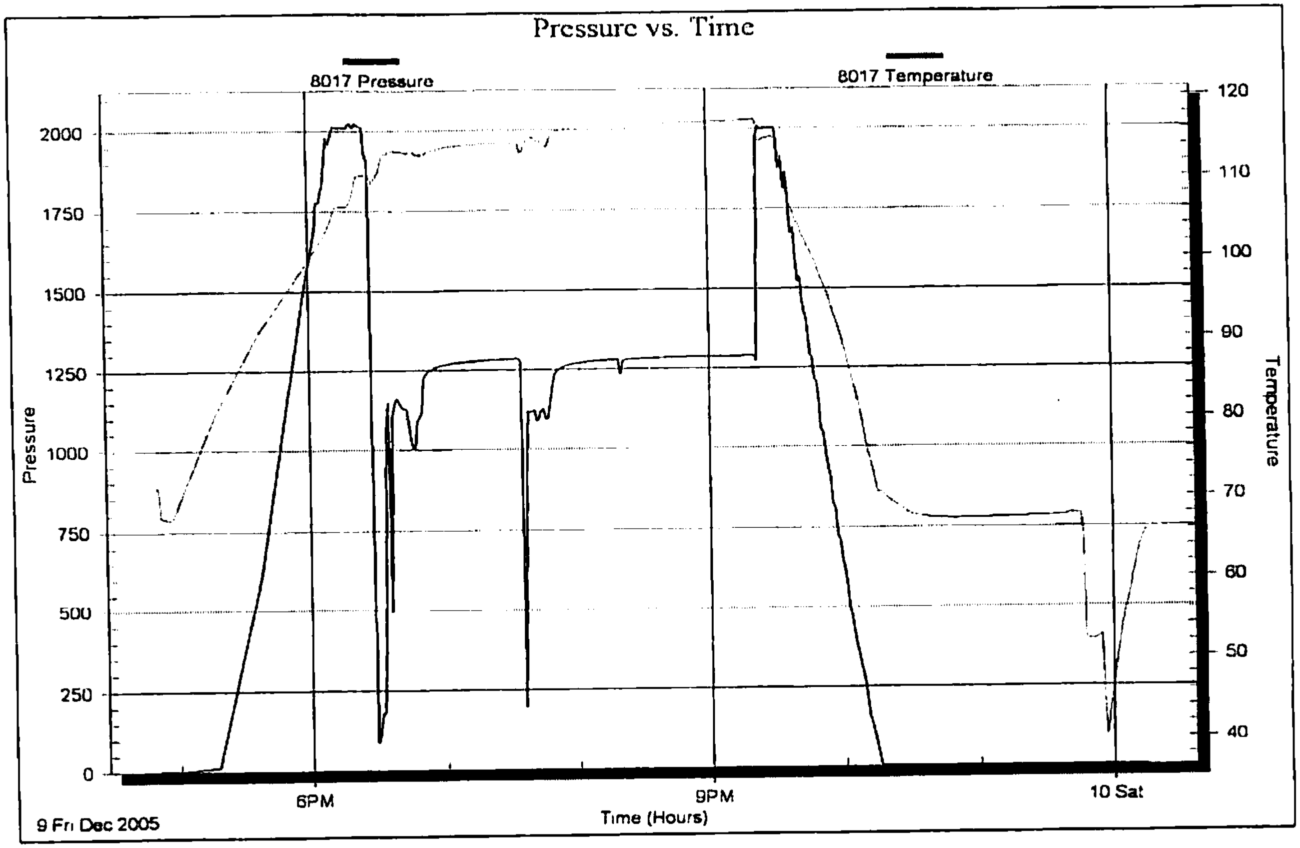
Serial #: 6752 Inside

DST Test Number: 3



Trilobite Testing, Inc Ref. No: 20572 Printed: 2006.02.27 @ 16:04:36 Page 1

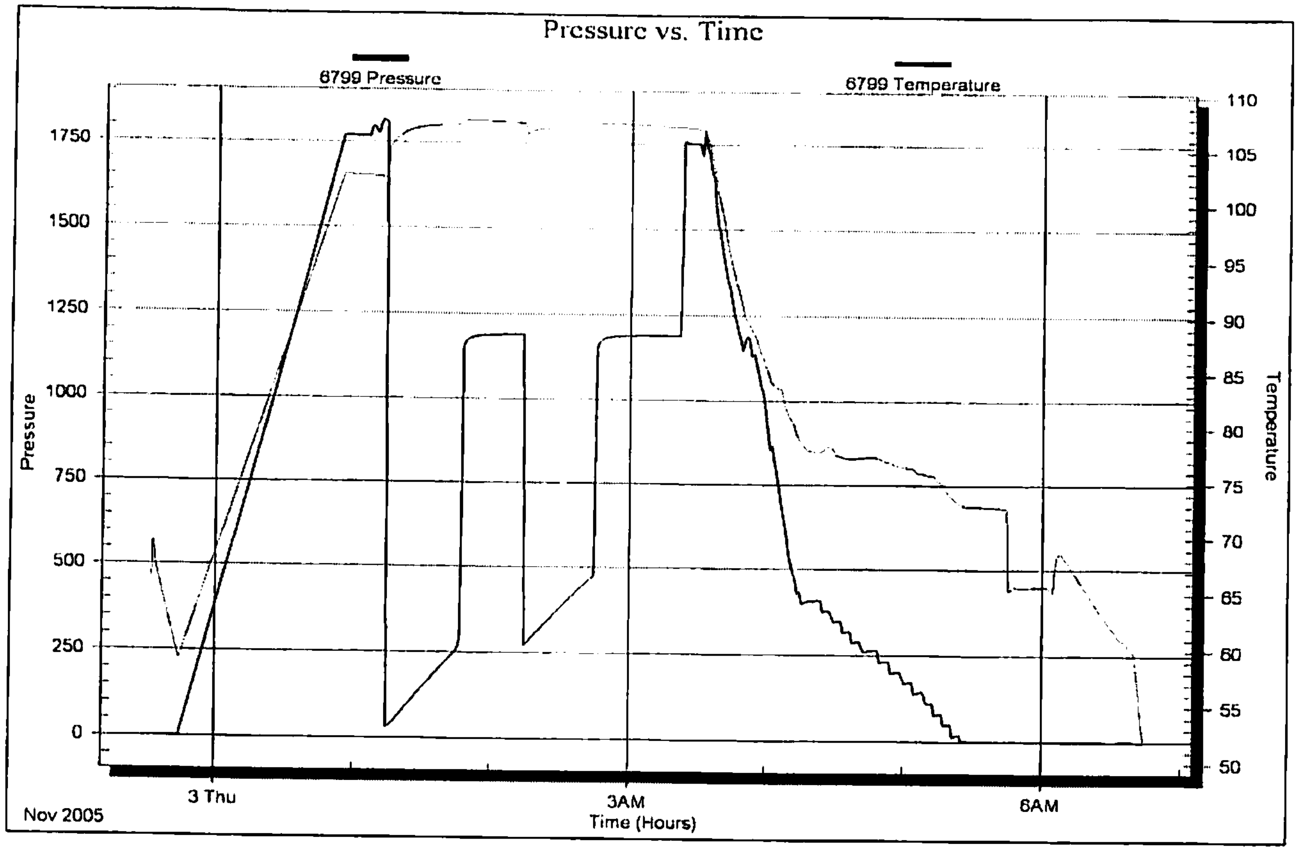
Initial flow plugged



Severe Plugging

Serial #: 6799 Inside

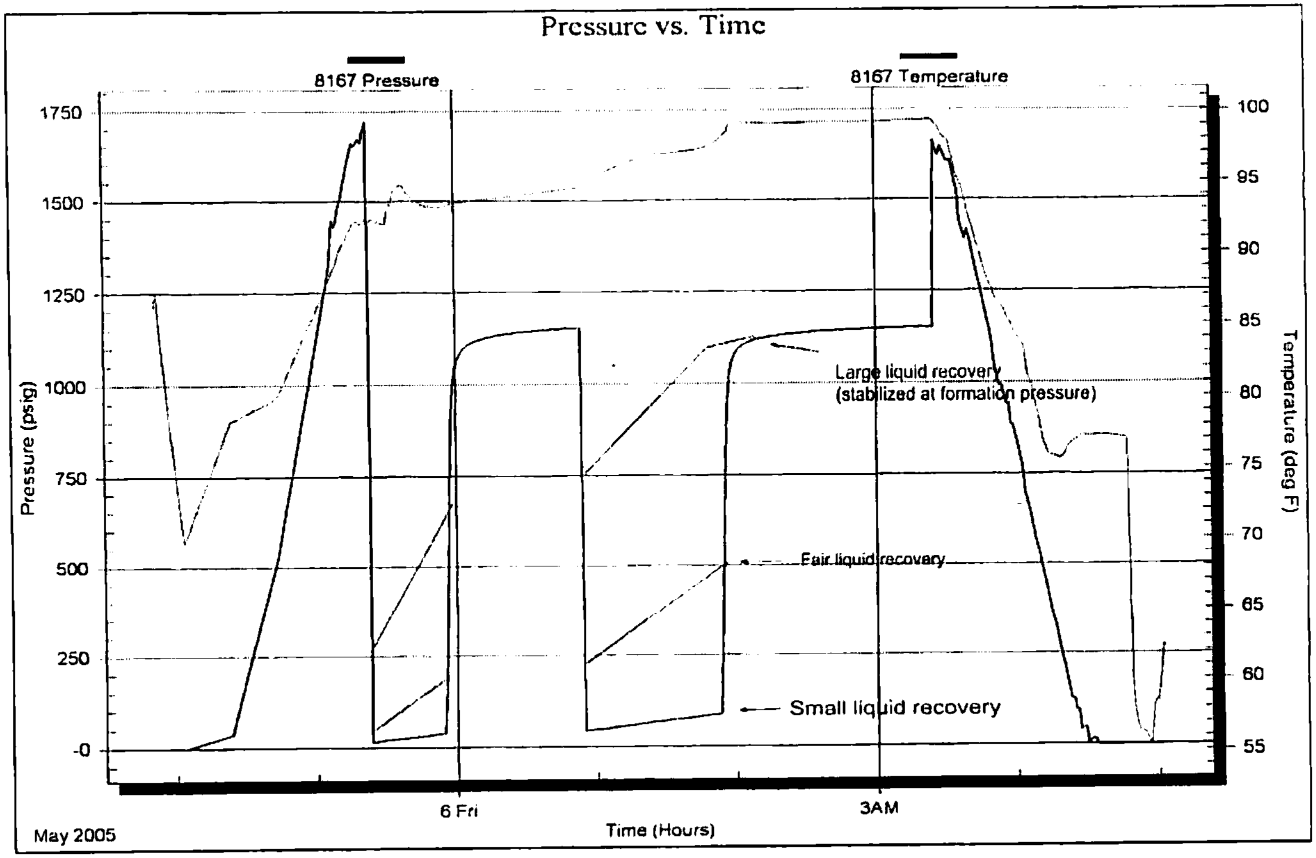
DST Test Number: 1



Trilobite Testing, Inc Ref. No 23329 Printed. 2006.02.27 @ 11:52:14 Page 2

Well Bore Damage

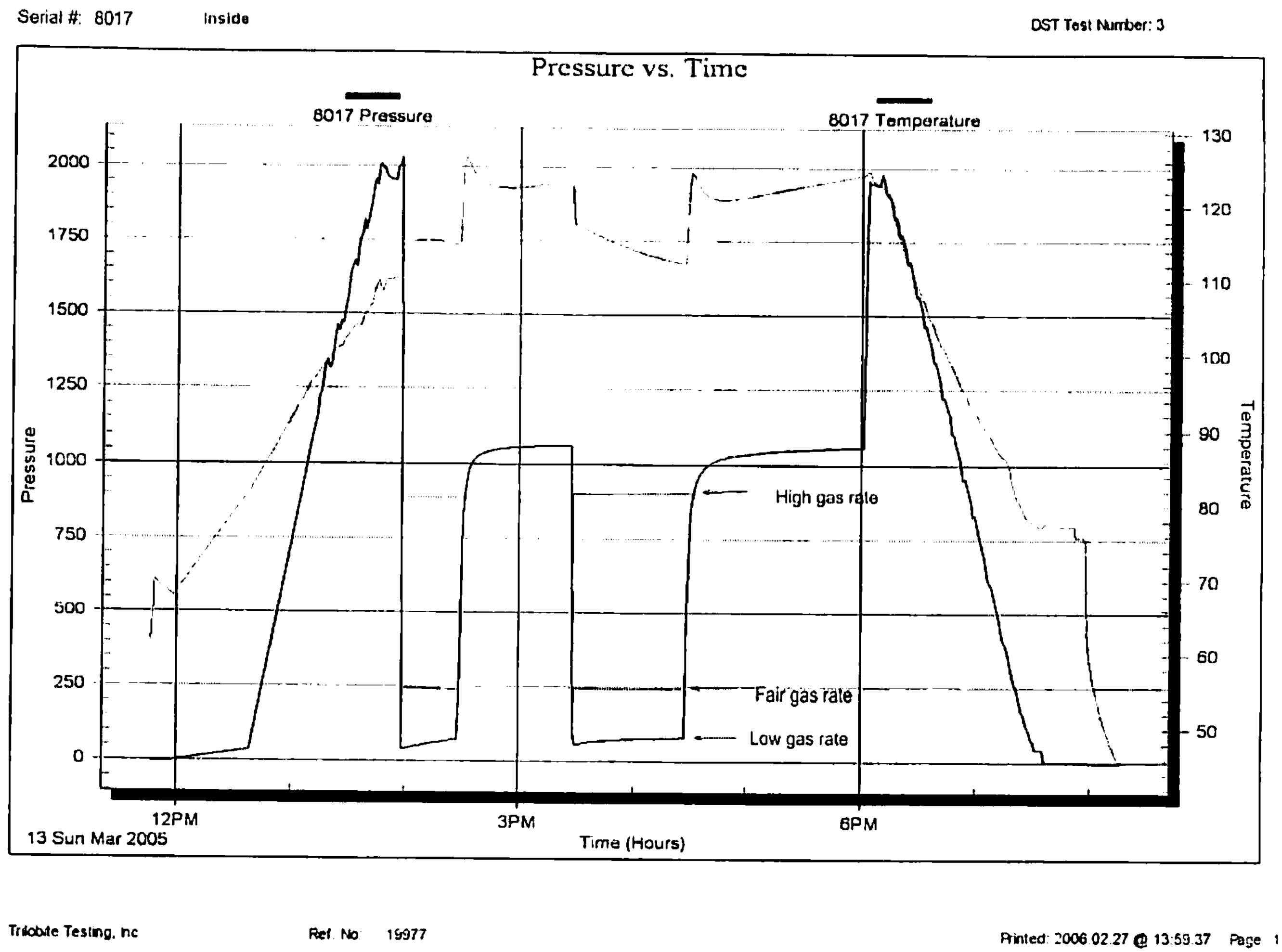
Serial # 8167 Inside DST Test Number: 8



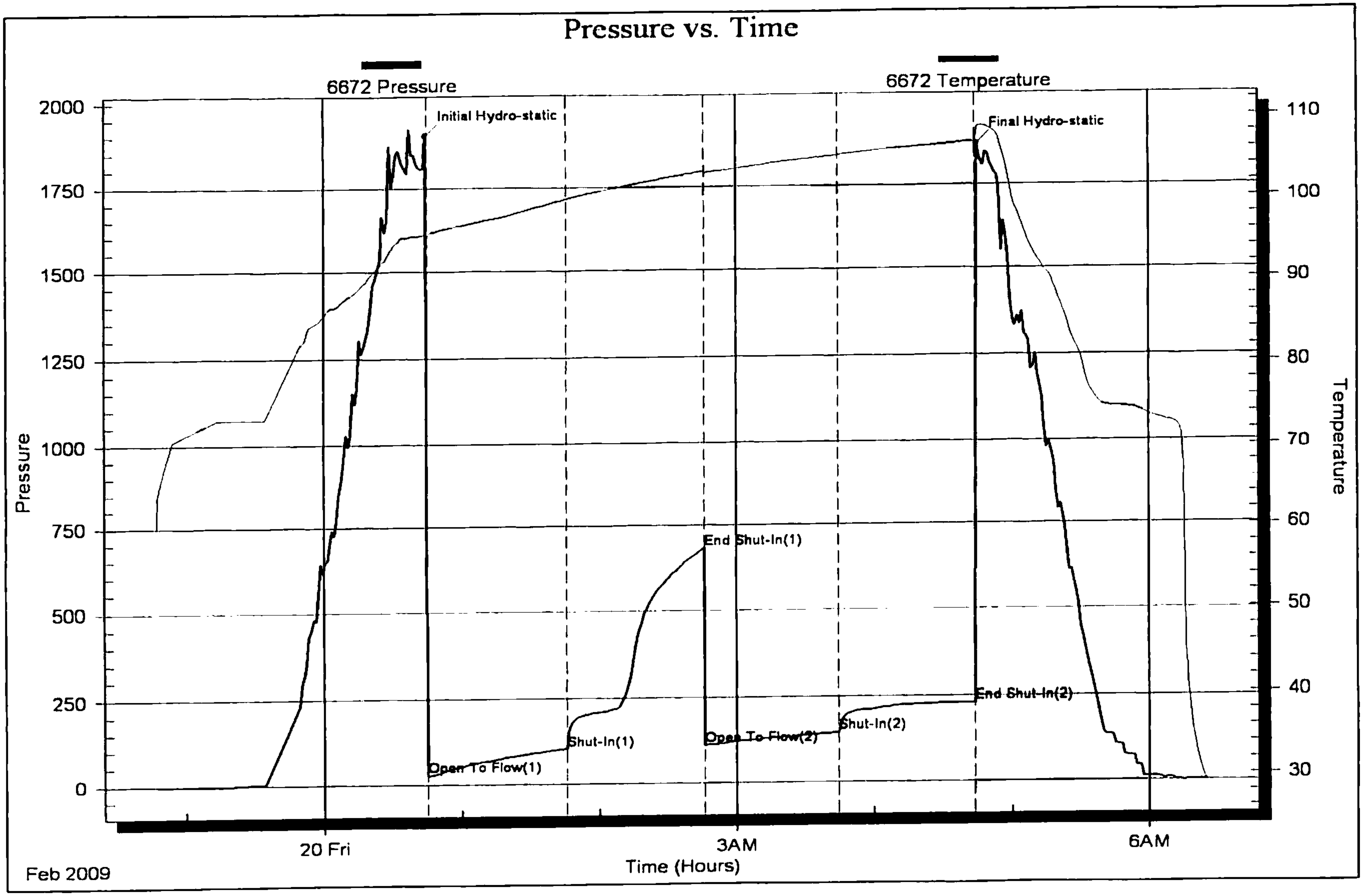
Trilobite Testing, Inc Ref. No: 22652 Printed: 2006.02.27 @ 13:57:26 Page 1

For liquid, the greater the increase in flow pressures,

The larger the column of liquid the reservoir pressure supports



For gas, the higher the static pressures, the larger the gas rate. The increases in pressure reflects back-pressure from the bottom choke.


Pressure vs. Time
6672 Pressure
6672 Temperature
Initial Hydro-static
Final Hydro-static
Open To Flow(1)
Shut-In(1)
End Shut-In(1)
Open To Flow(2)
Shut-In(2)
End Shut-In(2)
Pressure
2000
1750
1500
1250
1000
750
500
250
0
Temperature
110
100
90
80
70
60
50
40
30
20 Fri
3AM
6AM
Time (Hours)
Feb 2009