Pipeline Failure Investigation Report

Pipeline System: **Houstonia 200 Line** **Operator:** Panhandle Eastern Pipeline Company, LP

Location: Mile Post 21.6 **Date of Occurrence:** 8/25/2008

Medium Released: Natural gas **Quantity:** 13,518,578 CF

PHMSA Arrival Time & Date: 8/25/08 1:00 p.m. **Total Damages $** 1,046,359

Investigation Responsibility: ☐ State ☒ PHMSA ☐ NTSB Other ______

Company Reported Apparent Cause: ☒ Corrosion ☐ Excavation

☐ Natural Forces ☐ Incorrect Operation ☐ Other Outside Force Damage

☐ Material and/or Welds ☐ Equipment and Operations ☐ Other ______

Rupture	☒ Yes	☐ No
Leak	☐ Yes	☒ No
Fire	☐ Yes	☒ No
Explosion	☐ Yes	☒ No
Evacuation	☐ Yes	☒ No

Number of Persons _____ Area _____

Narrative Summary

Short summary of the Incident/Accident which will give interested persons sufficient information to make them aware of the basic scenario and facts.

Panhandle Eastern Pipeline Company (PEPL) experienced failure of the Houstonia 200 line near Mile Post 21.6. There were no evacuations, road closings, fires, injuries or fatalities as a result of the failure. The failure did not occur in a high consequence area (HCA).

The failure occurred on August 25, 2008, at approximately 8:51 a.m. CDT. The failure is located on a rocky hillside in a rural area west of Pilot Grove, Missouri in Cooper County. The failure was identified by PEPL when Houston Gas Control detected a pressure drop in the Houstonia 200 Line. The failure was located at approximately 9:00 a.m. when a PEPL field technician reported gas blowing near Mile Post 21.6. PEPL isolated the segment at approximately 9:30 a.m., by manually closing mainline valves 2 Gate and 3 Gate. The distance between 2 Gate and 3 Gate is approximately 16 miles.

The pipeline experienced a longitudinal rupture in the pipe body. The rupture created a 50 feet by 33 ft by 7 feet deep crater in the ground. Two pipeline segments totalling 28 feet in length and a coupling were ejected from the crater a distance up to 300 feet from the rupture site. The failure origin was a 16 inch long area of reduced wall thickness located at the 6:00 orientation.

The portion of the pipeline containing the failure is comprised of 24-inch diameter by 0.281-inch wall thickness, API 5L-X48, manufactured by A.O. Smith and contains a longitudinal electric flash welded (EFW) seam. The reported maximum allowable operating pressure (MAOP) is 800 psig, which corresponds to 71% of the specified minimum yield strength (SMYS). The pressure at the time and location of failure was 795 psig, which corresponds to 70% of the SMYS (99% of MAOP). The MAOP was established in accordance with 192.619 (c), the highest actual operating pressure to which the segment was subjected during the five years preceding July 1, 1970. A hydrostatic test of the pipeline was performed in 1955. Details of the hydrostatic test are unknown.

The pipeline, installed in 1937, is joined by circumferential girth welds and Dresser couplings. The pipeline external coating is coal tar. The pipeline has an impressed curent cathodic protection system that was reportedly energized in 1955.

The findings of PEPL's investigation are as follows:

1) The failure occurred due to tensile overload at a region of wall thinning caused by external corrosion.
2) The maximum wall loss measured at the rupture surface was 0.21 inches depth (75% of wall thickness).

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PEPL submitted a return to service plan to PHMSA that included a temporary 20% pressure reduction and remediation of anomalies found in a high resoultion MFL tool run. They subsequently remediated 30 anomalies with RPR less than 1.15 and replaced 912 feet of pipe. On 12/19/2009 the temporary pressure restriction was removed.

ACTIVITY #: 122653
OPERATOR ID #: 15105
UNIT ID #: 4093
NRC REPORT #: 881717
INCIDENT REPORT # (FORM 7100.2): 20090030 -- 5319

Region/State __Central________________________

Principal Investigator: _Roger Sneegas________

Date: _10/12/2010________________________

Reviewed by: __David Barrett__*original initialed*_______

Title: __Director – Central Region___________________

Date: __10/13/2010_________________________

Pipeline Failure Investigation Report

Failure Location & Response	
Location (City, Township, Range, County/Parish): (Acquire Map) Pilot Grove, Missouri	
Address or M.P. on Pipeline: (1) 21.6	Type of Area (Rural, City): (1) Rural
Date: 8/25/2008	Time of Failure: 8:51 a.m.
Time Detected: 9:00 a.m.	Time Located: 9:10 a.m.
How Located: A technician - Jerry Miller - heard the pipeline blowing from the nearest road at about 9:00 a.m. Gas control had previously noted a pressure drop at 8:51 a.m.	

NRC Report #: (Attach Report)	Time Reported to NRC:	Reported by:
881717	10:15 a.m. on 8/25/2008	Liz Rutherford

Type of Pipeline:

Gas Distribution	Gas Transmission	Hazardous Liquid	LNG
☐ LP	☒ Interstate Gas	☐ Interstate Liquid	☐ LNG Facility
☐ Municipal	☐ Intrastate Gas	☐ Intrastate Liquid	
☐ Public Utility	☐ Jurisdictional Gas Gathering	☐ Offshore Liquid	
☐ Master Meter	☐ Offshore Gas	☐ Jurisdictional Liquid Gathering	
	☐ Offshore Gas - High H_2S	☐ CO_2	

Pipeline Configuration (Regulator Station, Pump Station, Pipeline, etc.):
Mainline Houstonia 200

Operator/Owner Information	
Owner: Panhandle Eastern Pipeline	Operator: Panhandle Eastern Pipeline
Address: 5444 Westheimer Road Houston TX	Address: 5444 Westheimer Road Houston TX
Company Official: Eric Amundsen	Company Official: Eric Amundsen
Phone No.: 713-989-7460 Fax No.:	Phone No. 713-989-7460 Fax No.

Drug and Alcohol Testing Program Contacts ☐ N/A

Drug Program Contact & Phone: Brett Laaser

Alcohol Program Contact & Phone: 713-989-7549

Damages			
Product/Gas Loss or Spill[2]	13,518,578 CF	Estimated Property Damage $	25,000
Amount Recovered	0	Associated Damages[3] $	628,063

1 Photo documentation
2 Initial volume lost or spilled
3 Including cleanup cost

Pipeline Failure Investigation Report

Damages	
Estimated Amount $ 393,296	

Description of Property Damage:

The failure caused a crater in the right-of-way measuring about 50 X 33 feet and 7 feet deep. Two segments of pipe (46 feet total) were ejected from the crater.

Customers out of Service:	☐ Yes	☒ No	Number: _____
Suppliers out of Service:	☐ Yes	☒ No	Number: _____

Fatalities and Injuries

Fatalities:	☐ Yes	☒ No	Company: _____	Contractor: _____	Public: _____
Injuries - Hospitalization:	☐ Yes	☒ No	Company: _____	Contractor: _____	Public: _____
Injuries - Non-Hospitalization:	☐ Yes	☒ No	Company: _____	Contractor: _____	Public: _____
Total Injuries (including Non-Hospitalization):			Company: _____	Contractor: _____	Public: _____

Name	Job Function	Yrs w/ Comp.	Yrs. Exp.	Type of Injury

Drug/Alcohol Testing ☐ ***N/A***

Were all employees that could have contributed to the incident, post-accident tested within the 2 hour time frame for alcohol or the 32 hour time frame for all other drugs?

☒ Yes ☐ No

Job Function	Test Date & Time	Location	Results		Type of Drug
			Pos	Neg	
Gas System Controller	8/25/2008	Houston TX	☐	☒	
			☐	☐	
			☐	☐	
			☐	☐	
			☐	☐	

Pipeline Failure Investigation Report

System Description
Describe the Operator's System: The Houstonia 200 line runs from Liberal KS to Howell MI. It is 24-inch diameter 0.281-inch wall X48 pipe installed in 1937.

Pipe Failure Description ☐ *N/A*	
Length of Failure (inches, feet, miles): 46 feet (1)	
Position (Top, Bottom, include position on pipe, 6 O'clock): (1) Bottom 6 O'clock	Description of Failure (Corrosion Gouge, Seam Split): (1) External corrosion.
Laboratory Analysis: ☒ Yes ☐ No Performed by: CC Technologies Inc.	
Preservation of Failed Section or Component: ☒ Yes ☐ No If Yes - Method: Wrapped	
In Custody of: Panhandle	
Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Direction of Flow.	

Component Failure Description ☒ *N/A*	
Component Failed:	(1)
Manufacturer:	Model:
Pressure Rating:	Size
Other (Breakout Tank, Underground Storage):	

Pipe Data ☐ *N/A*	
Material: steel	Wall Thickness/SDR: 0.281- inch
Diameter (O.D.): 24-inch	Installation Date: 1937
SMYS: 48,000	Manufacturer: A. O. Smith
Longitudinal Seam: Electric Flash Weld	Type of Coating: Coal Tar
Pipe Specifications (API 5L, ASTM A53, etc.): API 5L, X48	

Joining ☐ *N/A*	
Type: Girth weld with Coupling every other joint	Procedure:
NDT Method: Unknown	Inspected: ☐ Yes ☐ No

Pipeline Failure Investigation Report

Pressure @ Time of Failure @ Failure Site ☐ ***N/A***				
Pressure @ Failure Site: 795 psig at the Houstonia Station		Elevation @ Failure Site: 660		
Pressure Readings @ Various Locations:			Direction from Failure Site	
Location/M.P./Station #	Pressure (psig)	Elevation (ft msl)	Upstream	Downstream
N/A				

Upstream Pump Station Data ☒ ***N/A***	
Type of Product:	API Gravity:
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure [4]	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Upstream Compressor Station Data ☐ ***N/A***	
Specific Gravity: .55	Flow Rate:
Pressure @ Time of Failure [4] 795 psig	Distance to Failure Site: 21.6 miles
High Pressure Set Point: 830 psig	Low Pressure Set Point:

Operating Pressure ☐ ***N/A***	
Max. Allowable Operating Pressure: 800 psig	Determination of MAOP: 192.619 (c)
Actual Operating Pressure: 795 psig	
Method of Over Pressure Protection: Engine safeties - first engine speed and torque, then shutdown.	
Relief Valve Set Point: 830 psig	Capacity Adequate? ☒ Yes ☐ No

Integrity Test After Failure ☐ ***N/A***
Pressure Test Conducted in place? (Conducted on Failed Components or Associated Piping): ☐ Yes ☒ No
If NO, Tested after removal? ☐ Yes ☒ No
Method: N/A
Describe any failures during the test.

Soil/water Conditions @ Failure Site ☐ ***N/A***
Condition of and Type of Soil around Failure Site (Color, Wet, Dry, Frost Depth): **Dry and very rocky**
Type of Backfill (Size and Description): **Rock**

4 Obtain event logs and pressure recording charts

Pipeline Failure Investigation Report

Soil/water Conditions @ Failure Site ☐ ***N/A***	
Type of Water (Salt, Brackish): **N/A**	Water Analysis [5] ☐ Yes ☒ No

External Pipe or Component Examination ***N/A***	
External Corrosion? ☒ Yes ☐ No [1]	Coating Condition (Disbonded, Non-existent): [1] Coal tar - some disbonded
Description of Corrosion: The failed pipeline segments showed multiple areas of external corrosion with reduced wall thickness.	
Description of Failure Surface (Gouges, Arc Burns, Wrinkle Bends, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of Origin): A 23 foot section of pipe was ejected and completely ruptured by the failure. Chevrons along the rupture pointed toward the origin in an area of external corrosion with reduced wall thickness.	
Above Ground: ☐ Yes ☒ No [1]	Buried: ☒ Yes ☐ No [1]
Stress Inducing Factors: [1]	Depth of Cover: 6 feet [1]

Cathodic Protection ☐ ***N/A***	
P/S (Surface): Readings taken this Spring were adequate - > .85 V - Recent reading in the area -2.1 V 3/26/08	P/S (Interface): Not taken
Soil Resistivity: No soil - rock pH:	Date of Installation: 1955
Method of Protection: **Rectifiers**	
Did the Operator have knowledge of Corrosion before the Incident? ☐ Yes ☒ No	
How Discovered? (Close Interval Survey, Instrumented Pig, Annual Survey, Rectifier Readings, ECDA, etc): **A close interval survey was performed in 2000 from 2 Gate to 3 Gate. Some areas of low pipe to soil potential were found but not in the area of the failure. See Appendix D.**	

Internal Pipe or Component Examination ☐ ***N/A***	
Internal Corrosion: ☐ Yes ☒ No [1]	Injected Inhibitors: ☐ Yes ☒ No
Type of Inhibitors: **N/A**	Testing: ☐ Yes ☒ No
Results (Coupon Test, Corrosion Resistance Probe): **N/A**	
Description of Failure Surface (MIC, Pitting, Wall Thinning, Chevrons, Fracture Mode, Point of Origin): **The cause of the failure was external corrosion with reduced wall thickness.**	
Cleaning Pig Program: ☒ Yes ☐ No	Gas and/or Liquid Analysis: ☐ Yes ☒ No

5 Attach copy of water analysis report

Pipeline Failure Investigation Report

Internal Pipe or Component Examination	☐ ***N/A***
Results of Gas and/or Liquid Analysis [6] **N/A**	
Internal Inspection Survey: ☐ Yes ☒ No	Results [7] ILI had been scheduled but not done.
Did the Operator have knowledge of Corrosion before the Incident? ☐ Yes ☒ No	
How Discovered? (Instrumented Pig, Coupon Testing, ICDA, etc.): **N/A**	

Outside Force Damage	☒ ***N/A***
Responsible Party:	Telephone No.:
Address:	
Work Being Performed:	
Equipment Involved: [1]	Called One Call System? ☐ Yes ☐ No
One Call Name:	One Call Report # [8]
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures? ☐ Yes ☐ No	
Pipeline Marking Type: [1]	Location: [1]
State Law Damage Prevention Program Followed? ☐ Yes ☐ No ☐ No State Law	
Notice Required: ☐ Yes ☐ No	Response Required: ☐ Yes ☐ No
Was Operator Member of State One Call? ☐ Yes ☐ No	Was Operator on Site? ☐ Yes ☐ No
Did a deficiency in the Public Awareness Program contribute to the accident? ☐ Yes ☐ No	
Is OSHA Notification Required? ☐ Yes ☐ No	

6 Attach copy of gas and/or liquid analysis report
7 Attach copy of internal inspection survey report
8 Attach copy of one-call report

Pipeline Failure Investigation Report

Natural Forces ☒ ***N/A***
Description (Earthquake, Tornado, Flooding, Erosion):

Failure Isolation ☐ ***N/A***	
Squeeze Off/Stopple Location and Method: (1) **Panhandle isolated the failure by manually closing 2 Gate and 3 Gate.**	
Valve Closed - Upstream: 2 Gate Time: 9:38 AM	I.D.: M.P.: 12.97
Valve Closed - Downstream: 3 Gate Time: 9:23	I.D.: M.P.: 28.43
Pipeline Shutdown Method: ☒ Manual ☐ Automatic ☐ SCADA ☐ Controller ☐ ESD	
Failed Section Bypassed or Isolated: Isolated	
Performed By: Field Tech.	Valve Spacing: 16 miles

Odorization ☒ ***N/A***		
Gas Odorized: ☐ Yes ☐ No	Concentration of Odorant (Post Incident at Failure Site):	
Method of Determination: ☐ Yes ☐ No	% LEL: ☐ Yes ☐ No	% Gas In Air: ☐ Yes ☐ No
	Time Taken: ☐ Yes ☐ No	
Was Odorizer Working Prior to the Incident? ☐ Yes ☐ No	Type of Odorizer (Wick, By-Pass):	
Odorant Manufacturer: Model:	Type of Odorant:	
Amount Injected:	Monitoring Interval (Weekly):	
Odorization History (Leaks Complaints, Low Odorant Levels, Monitoring Locations, Distances from Failure Site):		

Pipeline Failure Investigation Report

Odorization ☒ ***N/A***

Weather Conditions ☐ ***N/A***	
Temperature: 85 F	Wind (Direction & Speed): light
Climate (Snow, Rain): Sunny	Humidity:
Was Incident preceded by a rapid weather change? ☐ Yes ☒ No	
Weather Conditions Prior to Incident (Cloud Cover, Ceiling Heights, Snow, Rain, Fog): **Clear**	

Gas Migration Survey ☒ ***N/A***	
Bar Hole Test of Area: ☐ Yes ☐ No	Equipment Used:
Method of Survey (Foundations, Curbs, Manholes, Driveways, Mains, Services) [9] [1]	

Environment Sensitivity Impact ☒ ***N/A***	
Location (Nearest Rivers, Body of Water, Marshlands, Wildlife Refuge, City Water Supplies that could be or were affected by the medium loss): [1]	
OPA Contingency Plan Available? ☐ Yes ☐ No	Followed? ☐ Yes ☐ No

Class Location/High Consequence Area ☐ N/A	
Class Location: 1 ☒ 2 ☐ 3 ☐ 4 ☐ Determination: _____	HCA Area? ☐ Yes ☒ No ☐ N/A Determination: _____
Odorization Required? ☐ Yes ☒ No ☐ N/A	

Pressure Test History *(Expand List as Necessary)* ☐ **N/A**

9 Plot on site description page

Pipeline Failure Investigation Report

Pressure Test History *(Expand List as Necessary)* ☐ N/A						
	Req'd [10] Assessment Deadline Date	Test Date	Test Medium	Pressure (psig)	Duration (hrs)	% SMYS
Installation	N/A					
Next	N/A	1955	Water	Unknown	Unknown	Unknown
Next						
Most Recent						

Describe any problems experienced during the pressure tests.
Hydrostatic test done in 1955 - details unknown.

Internal Line Inspection/Other Assessment History *(Expand List as Necessary)* ☐ N/A					
	Req'd [10] Assessment Deadline Date	Assessment Date	Type of ILI Tool [11]	Other Assessment Method [12]	Indicated Anomaly If yes, describe below
Initial	**2012**				☐ Yes ☐ No
Next					☐ Yes ☐ No
Next					☐ Yes ☐ No
Most Recent					☐ Yes ☐ No

Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions.
Not scheduled until 2012. Not in top 50%. Gauge tool run already.

Pre-Failure Conditions and Actions ☐ N/A

Was there a known pre-failure condition requiring [10] the operator to schedule evaluation and remediation?
☐ Yes (describe below or on attachment) ☒ No

If there was such a known pre-failure condition, had the operator established and adhered to a required [10] evaluation and remediation schedule? Describe below or on attachment. ☐ Yes ☐ No ☒ N/A

Prior to the failure, had the operator performed the required [10] actions to address the threats that are now known to be related to the cause of this failure? ☐ Yes ☐ No ☒ N/A
List below or on an attachment such operator-identified threats, and operator actions taken prior to the accident.

Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions.
N/A

Maps & Records ☐ *N/A*

10 As required of Pipeline Integrity Management regulations in 49CFR Parts 192 and 195
11 MFL, geometry, crack, etc.
12 ECDA, ICDA, SCCDA, “other technology,” etc.

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Are Maps and Records Current? [13] ☒ Yes ☐ No Comments:	

Leak Survey History ☐ ***N/A***
Leak Survey History (Trend Analysis, Leak Plots): **Leak survey on 6/25/2007. No leaks were found in the area of the failure.**

Pipeline Operation History ☐ ***N/A***
Description (Repair or Leak Reports, Exposed Pipe Reports): **N/A**
Did a Safety Related Condition Exist Prior to Failure? ☐ Yes ☒ No Reported? ☐ Yes ☒ No
Unaccounted For Gas: **None before the incident.**
Over & Short/Line Balance (24 hr., Weekly, Monthly/Trend):

Operator/Contractor Error ☒ ***N/A***	
Name:	Job Function:
Title:	Years of Experience:
Training (Type of Training, Background):	
Was the person "Operator Qualified" as applicable to a precursor abnormal operating condition? ☐ Yes ☐ No ☐ N/A	
Was qualified individual suspended from performing covered task ☐ Yes ☐ No ☐ N/A	
Type of Error (Inadvertent Operation of a Valve):	
Procedures that are required:	
Actions that were taken:	
Pre-Job Meeting (Construction, Maintenance, Blow Down, Purging, Isolation):	
Prevention of Accidental Ignition (Tag & Lock Out, Hot Weld Permit):	
Procedures conducted for Accidental Ignition:	
Was a Company Inspector on the Job? ☐ Yes ☐ No	
Was an Inspection conducted on this portion of the job? ☐ Yes ☐ No	

13 Obtain copies of maps and records

Pipeline Failure Investigation Report

Operator/Contractor Error ☒ ***N/A***
Additional Actions (Contributing factors may include number of hours at work prior to failure or time of day work being conducted):
Training Procedures:
Operation Procedures:
Controller Activities:

Name	Title	Years Experience	Hours on Duty Prior to Failure	Shift

Alarm Parameters:
High/Low Pressure Shutdown:
Flow Rate:
Procedures for Clearing Alarms:
Type of Alarm:
Company Response Procedures for Abnormal Operations:
Over/Short Line Balance Procedures:
Frequency of Over/Short Line Balance:
Additional Actions:

Additional Actions Taken by the Operator ☐ ***N/A***
Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating downstream Pumps):

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Additional Actions Taken by the Operator ☐ *N/A*
The failure was detected by Gas Control in Houston at 8:51 a.m. on 8/25/2008. Field crews located the failure at 9:10 a.m. The failure was isolated by closing valves at about 9:30 a.m. **Panhandle sent a team to investigate the failure on 8/26/08. After the initial investigation, the pipeline was repaired and returned to service at 80% of the pressure at the time of the incident (795 psi) pending the results of the investigation.**

Pipeline Failure Investigation Report

Photo Documentation (1)					
Overall Area from best possible view. Pictures from the four points of the compass. Failed Component, Operator Action, Damages in Area, Address Markings, etc.					
Photo No.	Description	Roll No.	Photo No.	Description	Roll No.
1	View looking west at the crater		1		
2	East view of exposed pipe in crater		2		
3	West view of exposed pipe in crater		3		
4	View of longer ejected pipe segment		4		
5	Close view of longer segment		5		
6	View of shorter ejected segment		6		
7	Another view of shorter segment		7		
8	Possible failure origin on shorter segment		8		
9	Side view of possible failure.		9		
10	View of coupling ejected into the woods		10		
11	Close up of corrosion at possible failure origin.		11		
12	View of another area of external corrosion near the failure origin		12		
13	View of failure origin after the pipe was moved.		13		
14			14		
15			15		
16			16		
17			17		
18			18		
19			19		
20			20		
21			21		
22			22		
23			23		
24			24		
25			25		
26			26		
27			27		
28			28		
29			29		
30			30		
Type of Camera:					

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Photo Documentation (1)
Film ASA:
Video Counter Log (Attach Copy):

Additional Information Sources			
Agency	Name	Title	Phone Number
Police:	**Cooper County Sheriff**		
Fire Dept.:	**Pilot Grove Fire Dept**		
State Fire Marshall:			
State Agency:	**Missouri DOT Emergency Response Team**		
NTSB:			
EPA:			
FBI:			
ATF:			
OSHA:			
Insurance Co.:			
FRA:			
MMS:			
Television:	**No**		
Newspaper:			
Other:			

Pipeline Failure Investigation Report

Persons Interviewed		
Name	Title	Phone Number
Brad Howard	**Operations Specialist**	**660-568-1221**
Mike Dawson		
Steve Atkinson	**Technical Specialist**	**913-906-1522**
Jerry Rau	**Director Pipeline Integrity**	**713-989-7417**
Rob Wesch		
Liz Rutherford		
Brian Kraft	**Measurement Tech**	
Dan Corpening	**Area Director**	
Ross Cummins	**CP Tech**	
Richard Gifford	**Corrosion Tech**	
Gerald Moore	**Environmental Coordinator**	

Event Log	
Sequence of events prior, during, and after the incident by time. (Consider the events of all parties involved in the incident, Fire Department and Police reports, Operator Logs and other government agencies.)	
Time	Event
8:51 a.m. 8/25/08	**Gas Control detects a pressure drop on the Houstonia 200 line and asks field techs to check for a leak.**
9:00 a.m.	**Filed techs hear blowing gas near mile post 21.6**
9:10 a.m.	**Field techs locate the failure**
9:23 a.m.	**3 Gate at MP 28.43 is closed manually**
9:38 a.m.	**2 Gate at MP 12.97 is closed manually**
9:00 -11:00 a.m.	**Panhandle, Fire and police check the area to see if evacuations are necessary**
1:00 p.m.	**PHMSA investigator arrives on site.**
1:00 - 8:00 p.m.	**Investigation by PHMSA and Panhandle**
12:00 p.m. 8/26	**Panhandle investigation team from Houston arrives**
12:00 - 7:00 p.m.	**Investigation of the failure site by PHMSA and Panhandle.**

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Investigation Contact Log			
Time	Date	Name	Description
1:00 p.m.	**8/26/08**	**Brad Howard**	**Operations Specialist**
1:30 p.m.	**8/26/08**	**Steve Atkinson**	**Technical Specialist**
12:00 p.m.	**8/27/08**	**Jerry Rau**	**Director Pipeline Integrity**
1:00 p.m.	**8/26-10/20**	**Brad Howard**	**Follow up on various issues**
10:00 a.m.	**9/26/08**	**David McQuilling**	**Principal Engineer - conference call on cathodic protection**
10:00 a.m.	**9/26/08**	**Steve Atkinson**	**Same conference call.**

Failure Investigation Documentation Log				
Operator:	Unit #:	CPF #:	Date:	
Appendix Number	Documentation Description	Date Received	FOIA	
			Yes	No
A	**Investigation Pictures**	**8/25/08**		**X**
B	**Panhandle Incident Report**	**9/18/08**		**X**
C	**Panhandle Laboratory Failure Analysis**	**10/29/08**		**X**
D	**Panhandle Close Interval Survey**	**9/18/08**		**X**

Site Description
Provide a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

The Failure location was about two miles northwest of Pilot Grove (Cooper County) Missouri near Highway HH. The location was near milepost 21.6 on the Houstonia 200 line on a rocky hillside in a rural area. No structures were close to the failure location. The following page shows a sketch of the location provided by Panhandle. The image below shows the Panhandle system map.

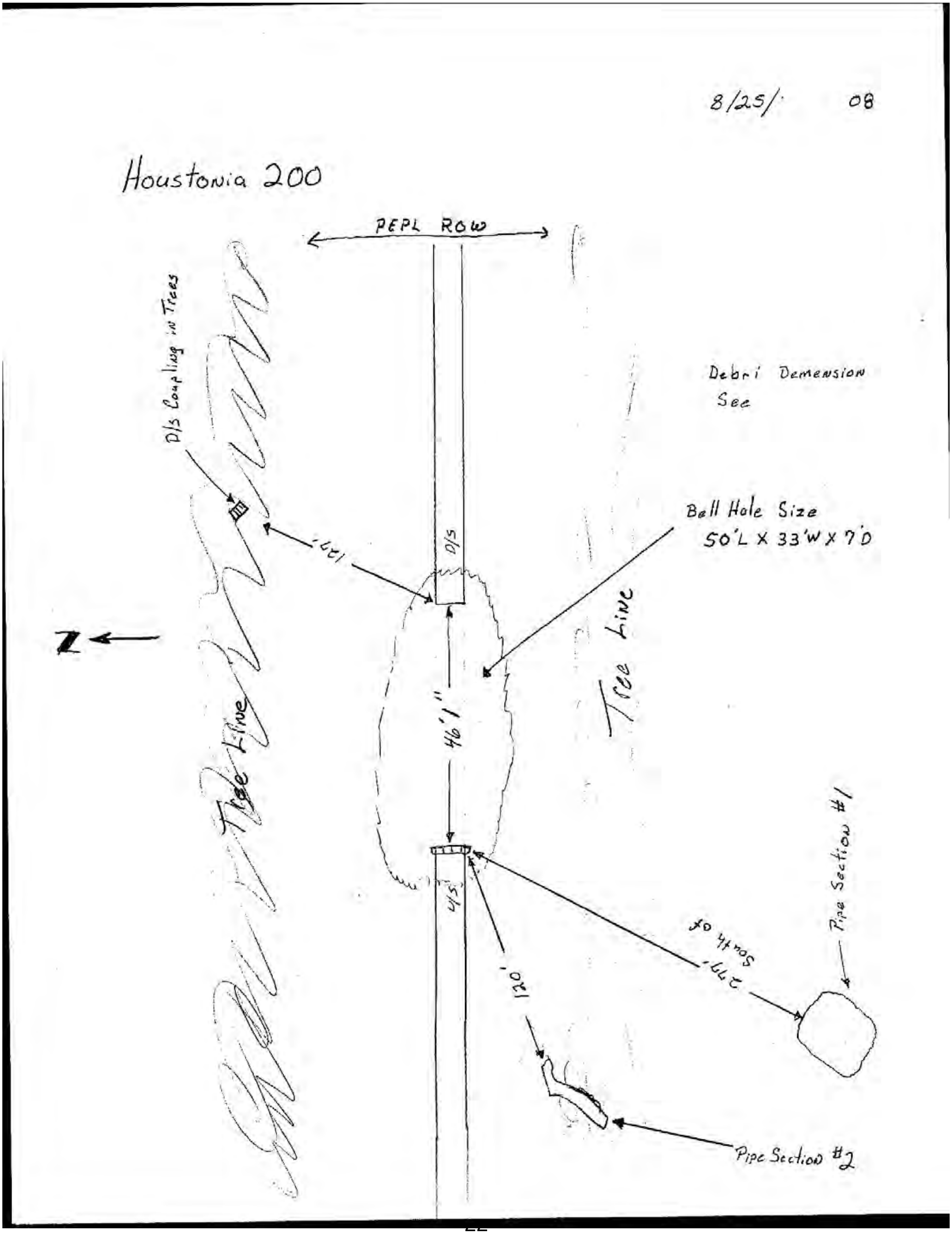
Panhandle Eastern Pipe Line Company, LP

Panhandle Eastern Pipe Line Company operates a 6,500-mile pipeline system with access to diverse supply sources and can deliver 2.8 Bcf/d of natural gas to Midwest and East Coast markets. Tie-ins to Chicago, Dayton and Cincinnati have added to a Midwest customer base that includes some of the nation's largest utility and industrial natural gas users. We lead the way in offering competitive rates and a constantly evolving array of customer-friendly service options.

Panhandle Eastern provides:

- Access to diverse Midcontinent and Canadian supply sources and to major Midwest and Northeast markets.
- Access to 74 Bcf of storage facilities.

To request a receipt and delivery point map, please contact Customer Service at 1-800-275-7375.


8/25/08
Houstonia 200
PEPL ROW
D/S Coupling in Trees
Debri Demension
See
Bell Hole Size
50'L X 33'W X 7'D
127'
D/S
N
46'1"
Tree Line
Tree Line
U/S
277' South of
120'
Pipe Section #1
Pipe Section #2

Appendix A

Houstonia 200 failure Pictures – 8/25/08 near Pilot Grove MO.

8/25/08 – #1- views looking West at the crater caused by the Houstonia 200 failure.

8/25/08 #2 - East view of the exposed pipe.

8/25/08 #3 -West close up.

8/25/08 #4 - One of two pipe sections ejected – the longer one – about 30 feet.

8/25/08 #5 -Closer view of the longer ejected section.

8/25/08 #6 -View of the shorter section ejected – about 23 feet – ruptured full length.

8/25/08 #7 -Another view of same looking north.

#8 - Areas with external corrosion and reduced wall thickness – possible failure origin.

8/25/08 #9 -Side view of the failure origin site with reduced wall thickness.

8/25/08 #10 -View of coupling ejected from pipeline.

8/25/08 #11 -Close up of external corrosion on the possible origin site.

8/25/08 #12 - Another area of external corrosion on the shorter section near the possible failure.

8/26/08 #13 -Different view of the possible failure origin after the pipe was turned over.

Appendix B

Panhandle Incident Report

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

Print

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING SYSTEMS

Report Date Sep 23, 2008

No. 20090030 -- 5319 (DOT Use Only)

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov .*

PART A – GENERAL REPORT INFORMATION

Check one or more boxes as appropriate:
☒ Original Report ☐ Supplemental Report ☒ Final Report

Operator Name and Address

a. Operator's 5-digit Identification Number (when known) / 15105 /

b. If Operator does not own the pipeline, enter Owner's 5-digit Identification Number (when known) / /

c. Name of Operator PANHANDLE EASTERN PIPELINE CO

d. Operator street address 5444 WESTHEIMER RD

e. Operator address HOUSTON, HARRIS, TX, 77056-5306
City, County or Parrish, State and Zip Code

2. Time and date of the incident
/ 900 / / 08 / / 25 / /2008/
hr. month day year

3. Location of incident

a. STATE ROAD HH
Nearest street or road

b. PILOT GROVE COOPER
City and County or Parrish

c. MO 65276
State and Zip Code

d. Mile Post/Valve Station VS 2

e. Survey Station No. 1140+00

f. Latitude: 38°54'09.5 N Longitude: 92° 58' 25 W
(if not available, see instructions for how to provide specific location)

g. Class location description
Onshore: ● Class 1 ◯ Class 2 ◯ Class 3 ◯ Class 4
Offshore: ◯ Class 1 (complete rest of this item)
Area ______ Block # ______
State / / or Outer Continental Shelf ☐

h. Incident on Federal Land other than Outer Continental Shelf
◯ Yes ● No

i. Is pipeline Interstate ● Yes ◯ No

4. Type of leak or rupture

◯ Leak: ◯ Pinhole ◯ Connection Failure (complete sec. F5)
◯ Puncture, diameter (inches) ______

● Rupture: ◯ Circumferential – Separation
● Longitudinal – Tear/Crack, length (inches) ______
Propagation Length, total, both sides (feet) 26

◯ N/A

◯ Other: ______

5. Consequences (check and complete all that apply)

a. ☐ Fatality Total number of people: / 0 /
Employees: / 0 / General Public: / 0 /
Non-employee Contractors: / 0 /

b. ☐ Injury requiring inpatient hospitalization Total number of people: / 0 /
Employees: / 0 / General Public: / 0 /
Non-employee Contractors: / 0 /

c. ☒ Property damage/loss (estimated) Total $ 1046359
Gas loss $ 393296 Operator damage $ 628063
Public/private property damage $ 25000

d. ☐ Release Occurred in a 'High Consequence Area'

e. ☐ Gas ignited – No explosion f. ☐ Explosion

g. ☐ Evacuation (general public only) / 0 / people
Reason for Evacuation:
◯ Emergency worker or public official ordered, precautionary
◯ Threat to the public ◯ Company policy

6. Elapsed time until area was made safe:
/ 0 / hr. / 38 / min.

7. Telephone Report
/ 881717 / / 08 / / 25 / /2008/
NRC Report Number month day year

8. a. Estimated pressure at point and time of incident:
790 PSIG

b. Max. allowable operating pressure (MAOP): 800 PSIG

c. MAOP established by 49 CFR section:
☐ 192.619 (a)(1) ☐ 192. 619 (a)(2) ☐ 192. 619 (a)(3)
☐ 192.619 (a)(4) ☒ 192. 619 (c)

d. Did an overpressurization occur relating to the incident? ◯ Yes ● No

PART B – PREPARER AND AUTHORIZED SIGNATURE

MARVIN HOVIS PRINCIPAL ENGINEER
(type or print) Preparer's Name and Title

(713) 989-7473
Area Code and Telephone Number

MARVIN.HOVIS@SUG.COM
Preparer's E-mail Address

(713) 989-1188
Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Code and Telephone Number

PART C - ORIGIN OF THE INCIDENT

1. Incident occurred on
   - ● Transmission System
   - ○ Gathering System
   - ○ Transmission Line of Distribution System

2. Failure occurred on
   - ● Body of pipe ○ Pipe Seam
   - ○ Joint
   - ○ Component
   - ○ Other: ______

3. Material involved *(pipe, fitting, or other component)*
   - ● Steel
   - ○ Plastic (If plastic, complete all items that apply in a-c)
     Plastic failure was: ☐ a.ductile ☐ b.brittle ☐ c.joint failure
   - ○ Material other than plastic or steel: ______

4. Part of system involved in incident
   - ● Pipeline ○ Regulator/Metering System
   - ○ Compressor Station ○ Other: ______

5. Year the pipe or component which failed was installed: / 1937 /

PART D – MATERIAL SPECIFICATION (if applicable)

1. Nominal pipe size *(NPS)* / 24 / in.
2. Wall thickness / .28 / in.
3. Specification ASME SMYS / 48000 /
4. Seam type EFW
5. Valve type ______
6. Pipe or valve manufactured by A O SMITH in year / 1937 /

PART E – ENVIRONMENT

1. Area of incident
   - ○ In open ditch
   - ○ Under pavement
   - ○ Above ground
   - ● Under ground
   - ○ Under water
   - ○ Inside/under building
   - ○ Other: ______
2. Depth of cover: 36 inches

PART F – APPARENT CAUSE

Important: *There are 25 numbered causes in this section. Check the box to the left of the* ***primary*** *cause of the incident. Check one circle in each of the supplemental items to the right of or below the cause you indicate. See the instructions for this form for guidance.*

F1 – CORROSION

If either F1 (1) External Corrosion, or F1 (2) Internal Corrosion is checked, complete all subparts a – e.

1. ● External Corrosion
2. ○ Internal Corrosion

a. Pipe Coating
   - ○ Bare
   - ● Coated

b. Visual Examination
   - ● Localized Pitting
   - ○ General Corrosion
   - ○ Other: ______

c. Cause of Corrosion
   - ● Galvanic ○ Stray Current
   - ○ Improper Cathodic Protection
   - ○ Microbiological
   - ○ Stress Corrosion Cracking
   - ○ Other: ______

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   ○ No ● Yes, Year Protection Started: / 1955 /

e. Was pipe previously damaged in the area of corrosion?
   ● No ○ Yes, How long prior to incident: / ______ / *years* / ______ / *months*

F2 – NATURAL FORCES

3. ○ Earth Movement => ○ Earthquake ○ Subsidence ○ Landslide ○ Other: ______
4. ○ Lightning
5. ○ Heavy Rains/Floods => ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other: ______
6. ○ Temperature => ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other: ______
7. ○ High Winds

F3 - EXCAVATION

8. ○ Operator Excavation Damage *(including their contractors)* / Not Third Party

9. ○ Third Party Excavation Damage *(complete a-d)*
   a. Excavator group
      ○ General Public ○ Government ○ Excavator other than Operator/subcontractor
   b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable ○ Landowner ○ Railroad
      ○ Other: ______
   c. Did operator get prior notification of excavation activity?
      ○ No ○ Yes: Date received: / ______ / mo. / ______ / day / ______ / yr.
      Notification received from: ○ One Call System ○ Excavator ○ Contractor ○ Landowner
   d. Was pipeline marked?
      ○ No ○ Yes *(If Yes, check applicable items i – iv)*
      i. Temporary markings: ○ Flags ○ Stakes ○ Paint
      ii. Permanent markings: ○ Yes ○ No
      iii. Marks were *(check one)* ○ Accurate ○ Not Accurate
      iv. Were marks made within required time? ○ Yes ○ No

F4 – OTHER OUTSIDE FORCE DAMAGE

10. ○ Fire/Explosion as primary cause of failure => Fire/Explosion cause: ○ Man made ○ Natural
11. ○ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ○ Rupture of Previously Damaged Pipe
13. ○ Vandalism

F5 – MATERIAL AND WELDS

Material

14. ◯ Body of Pipe => ◯ Dent ◯ Gouge ◯ Wrinkle Bend ◯ Arc Burn ◯ Other: ____________
15. ◯ Component => ◯ Valve ◯ Fitting ◯ Vessel ◯ Extruded Outlet ◯ Other: ____________
16. ◯ Joint => ◯ Gasket ◯ O-Ring ◯ Threads ◯ Other: ____________

Weld

17. ◯ Butt => ◯ Pipe ◯ Fabrication ◯ Other: ____________
18. ◯ Fillet => ◯ Branch ◯ Hot Tap ◯ Fitting ◯ Repair Sleeve ◯ Other: ____________
19. ◯ Pipe Seam => ◯ LF ERW ◯ DSAW ◯ Seamless ◯ Flash Weld
◯ HF ERW ◯ SAW ◯ Spiral ◯ Other: ____________

*Complete a-g if you indicate **any** cause in part F5.*

a. Type of failure:
◯ Construction Defect => ◯ Poor Workmanship ◯ Procedure not followed ◯ Poor Construction Procedures
◯ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? ◯ Yes ◯ No

c. Was part which leaked pressure tested before incident occurred? ◯ Yes, *complete d-g* ◯ No

d. Date of test: /______/ mo. /______/ day /______/ yr.

e. Test medium: ◯ Water ◯ Natural Gas ◯ Inert Gas ◯ Other: ____________________

f. Time held at test pressure: /______/ hr.

g. Estimated test pressure at point of incident: ____________________ *PSIG*

F6 – EQUIPMENT AND OPERATIONS

20. ◯ Malfunction of Control/Relief Equipment => ◯ Valve ◯ Instrumentation ◯ Pressure Regulator ◯ Other: ____________
21. ◯ Threads Stripped, Broken Pipe Coupling => ◯ Nipples ◯ Valve Threads ◯ Mechanical Couplings ◯ Other: ____________
22. ◯ Ruptured or Leaking Seal/Pump Packing

23. ◯ Incorrect Operation
a. Type: ◯ Inadequate Procedures ◯ Inadequate Safety Practices ◯ Failure to Follow Procedures ◯ Other: ____________
b. Number of employees involved who failed post-incident drug test: /__________/ Alcohol test: /__________/
c. Were most senior employee(s) involved qualified? ◯ Yes ◯ No d. Hours on duty: /______/

F7 – OTHER

24. ◯ Miscellaneous, *describe:* ______________________________
25. ◯ Unknown
◯ Investigation Complete ◯ Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART G – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

TENSILE OVERLOAD AT AN AREA OF WALL THINNING AT THE 6:00 CLOCK ORIENTATION DUE TO EXTERNAL CORROSION.

Appendix C

Panhandle Failure Analysis

CC Technologies
a DNV company

Metallurgical Analysis of 24-Inch Houstonia 200 Service Failure at MP 21.6 (8/25/08)

Panhandle Eastern Pipe Line Company, LP
Final Report – 813 8385 1
October 29, 2008

MANAGING RISK DNV

CC TECHNOLOGIES, INC.

Metallurgical Analysis of 24-Inch Houstonia 200 Service Failure at MP 21.6 (8/25/08)
for

Panhandle Eastern Pipe Line Company, L.P.
5444 Westheimer, Suite 432
Houston, TX 77056

5777 Frantz Road
Dublin, Ohio 43017-1386
U.S.A.

Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnv.com
www.cctechnologies.com

Summary:	Final Report
Prepared by:	Gregory T. Quickel, M.S. Staff Engineer
Reviewed by:	John Beavers, Ph.D., FNACE . Director – Failure Analysis
Approved by:	Patrick H. Vieth Senior VP – Integrity & Materials
Date of Issue:	October 29, 2008
Project Number:	813 8385 1

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Disclaimer

This report documents work performed by CC Technologies, Inc. (*CC Technologies*) Dublin, Ohio, for Panhandle Eastern Pipe Line Company, L.P. (*Panhandle*) Houston, Texas. Neither CC Technologies nor any person acting on behalf of CC Technologies:

- assumes any liability for consequences or damages resulting from the use, misuse, or reliance upon the information disclosed in this report.
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Executive Summary

Panhandle Eastern Pipe Line Company, L.P (*Panhandle*) retained CC Technologies, Inc. (*CC Technologies*) to perform a metallurgical analysis on a section of pipe from the 24-inch diameter Houstonia 200 natural gas pipeline that failed during service. The failure occurred on August 25, 2008 near Pilot Grove (Cooper County), Missouri at milepost (MP) 21.6.

The portion of the pipeline containing the failure is comprised of 24-inch diameter by 0.281-inch wall thickness line pipe with an estimated yield strength (EYS) of 48.0 ksi that was manufactured by A.O. Smith and contains an electric flash welded (EFW) longitudinal seam. The maximum allowable operating pressure (MAOP) and normal operating pressure are 800 psig, which corresponds to 71.2% of the EYS. The operating pressure at the time and location of the failure was 790 psig, which corresponds to 70.3% of the EYS.

The pipeline was installed in 1937 and was reportedly externally coated with a bitumastic pipe wrap. The pipeline has an impressed current cathodic protection (CP) system that was installed between 1951 and 1953. CP readings taken on March 25th, 2008 in the vicinity of the failure were -4.162 V (on) and -1.320 V (off).

A hydrostatic pressure test was performed in 1955 on Segments 1031+39 to 1317+15, which encompasses the failure site.

Four segments of line pipe steel, one which contained the failure origin, were delivered to CC Technologies for analysis. The received segments consisted of: a segment that contained the upstream (U/S) girth weld and failure origin, a mating downstream (D/S) segment, the D/S arrest segment from the joint that failed, and a segment of pipe from the joint D/S of the joint that failed. The objective of the analysis was to document the factual metallurgical evidence.

The pipe segments were visually examined and photographed in the as-received condition. Scale samples were removed from the external pipe surface, at and away from a region of wall loss near the failure origin. The following was performed on the scale samples: elemental analysis using energy-dispersive spectroscopy (EDS) with a scanning electron microscope (SEM), bacteria culture inoculation using a serial dilution technique, and qualitative spot testing using 2N HCl for the presence of carbonates and/or sulfides. A grid with 1-inch by 1-inch divisions was drawn on the internal surface of the pipe near the failure origin where external wall loss was present. Wall thickness values were recorded every 1 inch (measured on the internal surface) with an ultrasonic testing (UT) gauge and/or with calipers. Calipers were used where the UT gauge could not be used, because of sharp bends in the pipe. The external surface at the wall loss region near the failure origin was cleaned with a soft bristle brush and inhibited acid. Magnetic particle inspection (MPI) was performed on the external surface at the wall loss region near the failure origin to identify any indications. Transverse cross-sections were removed from the failure origin and seam weld, mounted, polished, and etched. Light photomicrographs were taken to document the corrosion morphology and steel microstructure.

Executive Summary (continued)

A pipe sample for chemical analysis was removed from the joint that failed to determine the composition. Transverse pipe samples for mechanical (duplicate tensiles and Charpy V-notch impact) testing were removed from the base metal of the downstream joint.

The predicted burst pressure for the region of wall loss that contained the rupture was calculated using the RSTRENG effective area method embodied in CorLAS™. Two flaw profiles were obtained. The first flaw profile (profile 1) was obtained by using a modified river bottom method. A second flaw profile (profile 2) was constructed by measuring the wall thicknesses at the edge of the counter-clockwise fracture surface. A flow strength of the measured yield stress (MYS)+10 ksi was used for the calculation.

Below is a summary of our preliminary observations and conclusions:

- The failure occurred at a region of external wall loss from corrosion.
- The maximum depth of wall loss at the rupture surface was 0.210 inches (74.7% of wall thickness).
- Bacteria did not likely play a role in the external corrosion based on the morphology of the corrosion and the results of the bacteria culture testing.
- The morphology of the fracture surfaces suggests that the failure initiated in a ductile manner.
- The morphology of the seam weld is consistent with an EFW seam.
- The microstructure and steel composition are consistent with line pipe steel.
- The results of the tensile and Charpy testing are consistent with this vintage of line pipe steel.
- The estimated burst pressure ranged between 663 psig to 868 psig, compared to an actual failure pressure of 790 psig.

Contents

Tables

Figures

1.0 BACKGROUND

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Four segments of line pipe steel, one which contained the failure origin, were delivered to CC Technologies for analysis. The received segments consisted of a segment that contained the upstream (U/S) girth weld and failure origin, a mating downstream (D/S) segment, the D/S arrest segment from the joint that failed, and a segment of pipe from the joint D/S of the joint that failed. The objective of the analysis was to document the factual metallurgical evidence.

2.0 APPROACH

The procedures used in the analysis were in accordance with industry accepted standards. Six of the general standards governing terminology, chemical analysis, mechanical testing, and specific metallographic procedures used are as follows:

- ASTM E3, “Standard Methods of Preparation of Metallographic Specimens.”
- ASTM E7, “Standard Terminology Relating to Metallography.”
- ASTM E8, “Test Methods for Tension Testing of Metallic Materials.”
- ASTM E23, “Standard Test Methods for Notched Bar Impact Testing of Metallic Materials.”
- ASTM A751, “Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products.”
- ASTM G15, “Standard Terminology Relating to Corrosion and Corrosion Testing.”

The pipe segments were visually examined and photographed in the as-received condition. Scale samples were removed from the external pipe surface, at and away from a region of wall loss near the failure origin. The following was performed on the scale samples: elemental analysis using energy-dispersive spectroscopy (EDS) with a scanning electron microscope (SEM), bacteria culture inoculation using a serial dilution technique, and qualitative spot testing using 2N HCl for the presence of carbonates and/or sulfides. A grid with 1-inch by 1-inch divisions was drawn on the internal surface of the pipe near the failure origin where external wall loss was present. Wall thickness values were recorded every 1 inch (measured on the internal surface) with an ultrasonic testing (UT) gauge and/or with calipers. Calipers were used where the UT gauge could not be used, because of sharp bends in the pipe. The external surface at the wall loss region near the failure origin was cleaned with a soft bristle brush and inhibited acid. Magnetic particle inspection (MPI) was performed on the external surface at the wall loss region near the failure origin to identify any indications. Transverse cross-sections were removed from the failure origin and seam weld, mounted, polished, and etched. Light photomicrographs were taken to document the corrosion morphology and steel microstructure. A pipe sample for chemical analysis was removed from the joint that failed to determine the composition. Transverse pipe samples for mechanical (duplicate tensiles and Charpy V-notch impact) testing were removed from the base metal of the downstream joint.

The predicted burst pressure for the region of wall loss that contained the rupture was calculated using the RSTRENG effective area method embodied in CorLAS™. Two flaw profiles were obtained. The first flaw profile (profile 1) was obtained by using a modified river bottom method. A second flaw profile (profile 2) was constructed by measuring the wall thicknesses at the edge of the counter-clockwise fracture surface. A flow strength of the measured yield stress (MYS)+10 ksi was used for the calculation.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 1 through Figure 4 are photographs of the four as-received pipe segments. The pipe segments were designated as Pipe Segment A1, A2, B1, and C and by Panhandle personnel. Pipe Segments A1, B1, and A2 contained portions of the rupture paths. Pipe Segment C did not contain a rupture path and was used for mechanical testing. None of the pipe segments contained in-tact coating (in the as-received condition) and all segments, except for Segment C, contained localize regions of wall loss. Top-dead-center (TDC) was not indicated on the pipe segments. Flow direction was not identified on the pipe segments but is labeled on pipe segments that ruptured.

The wall thicknesses were measured at four equally spaced locations on the pipe segments. The wall thickness values for the segments are shown in Table 1. The wall thickness values were consistent with a nominal wall thickness of 0.281 inches.

Figure 1 is a photograph of the internal surface of Pipe Segment A1 is the as-received condition. The pipe segment was approximately 6.5 feet in length and was the D/S mating segment to Segment A2. The seam weld is located between the two rupture faces. The orientation of the chevron markings on the rupture surfaces indicated that the failure origin was U/S.

Figure 2 is a photograph of the external and internal surfaces of Pipe Segment B1 in the as-received condition. Pipe Segment B1 was approximately 11 feet in length from the joint that ruptured, and contained the D/S portion of rupture arrest. Again, the orientation of the chevron markings on the rupture surfaces indicated that the failure origin was U/S of this segment.

Figure 3 is a photograph of the external surface of Pipe Segment C in the as-received condition. The pipe segment was approximately 1.5 feet in length, was from the joint D/S of the joint that ruptured, and was intact. The diameter of the pipe segment was 23.9 inches, which is consistent with a nominal diameter of 24 inches.

Figure 4 is a photograph of Pipe Segment A2 in the as-received condition. The pipe segment was approximately 4.2 feet in length and U/S of Pipe Segment A1. Chevron markings that were located on the fracture surfaces pointed to a rupture origin in the segment. Figure 5 and Figure 6 are photographs of the external pipe surface on the clockwise and counter-clockwise side of the rupture path, respectively. Corrosion wall loss is located on the external pipe surface on adjacent surfaces. The corroded region extended 0.5 feet to 1.79 feet from the U/S girth weld and the fracture surface within the region was at a 45° angle, indicating a shear type of failure. Outside of the region, the fracture surface contained chevron marks and was predominantly perpendicular to the pipe surface.

Figure 7 shows remaining wall produced from wall thickness measurements obtained. The measurements were recorded from approximately 34 to 47 inches clockwise of the seam weld and from 6 to 25-inches D/S of the U/S girth weld. The rupture surface regions were located approximately 40 to 41 inches clockwise of the seam weld (looking D/S). This figure shows that the maximum depth of attack ranges from 0.05 to 0.1 inches and the deepest portions of the attack are at/near the fracture surface. Based on a wall thickness of 0.281 inches, the maximum depth of wall loss was 0.188 inches (66.9% of wall thickness).

3.2 Magnetic Particle Inspection (MPI)

MPI was performed on the external pipe surface in the region of wall loss associated with the failure origin. No evidence of linear indications was identified on the pipe body.

3.3 Metallurgical Analysis

Figure 8 is a photograph of the mounted transverse cross-section (Mount M1) removed near the rupture origin (see Figure 5 and Figure 6 for location). The cross-section shows significant wall loss. Figure 9 is a stereo light photomicrograph of the area indicated in Figure 8. The rupture surfaces are at approximately a 45° angle to each other and there is evidence of necking near the rupture surfaces. Both observations are indicative of a ductile overload failure. Figure 10 is a light photomicrograph showing the cross-section of Mount M1 near the external surface. The figure shows a banded microstructure and there was no evidence in the cross-section of morphology that is indicative of microbial influenced corrosion (MIC).

Figure 11 is a stereo light photomicrograph of the mounted cross-section that was removed from the seam weld. The morphology of the weld is consistent with an EFW seam.

Figure 12 is a light photomicrograph of the typical microstructure of the base metal from Mount M2. The microstructure consists of ferrite (white areas), pearlite (dark areas consisting of lamellae), and inclusions. This microstructure is typical for this vintage and grade of line pipe steel.

3.4 Energy Dispersive Spectroscopy (EDS)

Table 2 is a summary of the EDS results of the scale samples removed from the external pipe surface; see Figure 5 for the locations where the scale was removed. Sample A was removed from the region of wall loss and Sample B was removed away from the region of wall loss. Figure 13 shows a representative EDS spectrum. High amounts of oxygen (O) and iron (Fe), lesser amounts of sodium (Na), magnesium (Mg), aluminum (Al), silicon (Si), sulfur (S), potassium (K), calcium (Ca), manganese (Mn), and carbon (C) were found in the samples.

The Fe and O were likely in the form of an iron oxide and other elements are commonly found in soils.

3.5 Qualitative Spot Test

Spot tests for the presence of carbonates and/or sulfides were performed on scale at locations where samples were removed for elemental analysis. The deposits were positive for the presence of carbonates (bubbling) and negative for the presence of sulfides (no rotten egg odor). Carbonates are commonly associated with CP.

3.6 Bacteria Culture Testing

Scale samples were removed from the external surface, inoculated, and incubated for the presence of aerobic, anaerobic, sulfate-reducing (SRB), acid-producing (APB), and iron-related bacteria (IRB) in concentrations ranging from 1-99,999 bacteria per mL. The samples were removed from the same locations where samples were removed for elemental analysis. Table 3 shows the results of the bacteria testing for the scale samples. The scale samples removed from both locations were positive for the presence of aerobic bacteria, anaerobic bacteria, and acid-producing bacteria (APB) in very high (10,000 – 99,999 bacteria per mL) concentrations. The fact that there was no evidence of an increased concentration of the bacteria near the failure site suggests that bacteria did not play a role in the failure.

3.7 Mechanical Test Results

The results of the tensile testing for samples removed from the Segment C (D/S joint) are shown in Table 4. The MYS and ultimate tensile strength (UTS) for the pipe segment were determined to be 51.8-ksi and 71.5-ksi, respectively, compared to an EYS of 48.0-ksi. The failure joint was not tested since it was deformed during the failure event.

Table 5 summarizes the results of the Charpy testing while Figure 14 and Figure 15 show the Charpy percent shear and impact energy curves, respectively. An analysis of the data indicates that the 85% FATT is 96.8°F and the upper shelf Charpy energy is 38.8-ft·lbs, full size. The CVN test results can be adjusted to account for material constraint effects by applying temperature shifts to the data.* The modified transition temperatures (brittle-to-ductile fracture initiation temperature) for the pipe segment were estimated as 90.4°F, based on a pipe wall thickness of 0.281 inches; see Table 6. Based on this analysis, the tested material is expected to exhibit ductile fracture propagation behavior above 90.4°F.

3.8 Chemical Analysis

The results of the chemical composition analysis conducted on a sample removed from the pipe section that ruptured are shown in Table 7. The composition is consistent with this vintage of line pipe steel.

3.9 Predicted Burst Pressure

The predicted burst pressure for the region of wall loss that contained the rupture was calculated using the RSTRENG effective area method embodied in CorLAS™. The predicted burst pressure relied upon the remaining wall thicknesses measurements at and near the rupture of flaw profile 1 and 2, the average mechanical properties from the mechanical testing, and the pipe dimensions; see Figure 16 for flaw profiles. The results of the analysis are summarized in Appendix A. The maximum depth of wall loss in flaw profile 1 and 2 were 0.188 inches (66.9% of wall thickness) and 0.210 inches (74.7% of wall thickness), respectively. The estimated burst pressure ranged between 663 psig to 868 psig, compared to an actual failure pressure of 790 psig.

4.0 CONCLUSIONS

Below is a summary of our preliminary observations and conclusions:

- The failure occurred at a region of external wall loss from corrosion.
- The maximum depth of wall loss at the rupture surface was 0.210 inches (74.7% of wall thickness).
- Bacteria did not likely play a role in the external corrosion based on the morphology of the corrosion and the results of the bacteria culture testing.
- The morphology of the fracture surfaces suggests that the failure initiated in a ductile manner.

* "A Simple *Procedure* for Synthesizing Charpy Impact Energy Transition Curves from Limited Test Data," Michael J. Rosenfeld, International Pipeline Conference – Volume 1, ASME 1996, p. 216.

- The morphology of the seam weld is consistent with an EFW seam.
- The microstructure and steel composition are consistent with line pipe steel.
- The results of the tensile and Charpy testing are consistent with this vintage of line pipe steel.
- The estimated burst pressure ranged between 663 psig to 868 psig, compared to an actual failure pressure of 790 psig.

Table 1. Summary of the results (in areas of minimal or no corrosion) of wall thickness measurements performed on the pipe segments.

Segment ID	Description	Wall Thickness 1 (inches)	Wall Thickness 2 (inches)	Wall Thickness 3 (inches)	Wall Thickness 4 (inches)
A1	D/S of and cut from Segment A2	0.271	0.275	0.281	0.280
A2	Segment that contained U/S girth weld and failure origin	0.282	0.281	0.278	0.275
B1	D/S arrest segment	0.279	0.276	0.280	0.280
C	Segment for mechanicals	0.281	0.281	0.282	0.283

Table 2. Results of elemental analysis of scale samples removed from the external pipe surface using energy dispersive spectroscopy (EDS).

	Location A, Corroded Region (wt %)	Location B, Non-Corroded Region (wt %)
O	26	68
Na	<1	-
Mg	<1	3.4
Al	<1	1.6
Si	<1	5.6
S	<1	<1
K	<1	<1
Ca	1.5	4.3
Mn	1.3	-
C	-	15
Fe	69	2.1

Table 3. Results of bacteria analysis performed on scale samples removed from the external surfaces, at and away from the region of external corrosion.

	Scale from Location A		Scale from Location B	
	Test Result	**Bacteria Concentration**	**Test Result**	**Bacteria Concentration**
Aerobic	positive	Very High	positive	Very High
Anaerobic	positive	Very High	positive	Very High
Acid-Producing	positive	Very High	positive	Very High
Sulfate-Reducing	negative	-	negative	-
Iron-Related	negative	-	negative	-

Bacteria Concentration Key:

Very Low (1 – 9 bacteria per mL),
Low (10 – 99 bacteria per mL),
Moderate (100 – 999 bacteria per mL),
High (1,000 – 9,999 bacteria per mL),
Very High (10,000 – 99,999 bacteria per mL)

Table 4. Results of tensile tests performed on transverse samples from Pipe Segment C (D/S of failure joint).

	Pipe Segment C
Yield Strength, ksi	51.8
Tensile Strength, ksi	71.5
Elongation in 2 inches, %	33.0
Reduction of Area, %	52.0

Table 5. Results of Charpy V-notch impact tests performed on samples removed from the base metal of Pipe Segment C.

Sample ID	Temperature, °F	Sub-size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
1	-30	2	3.5	0	0
2	-5	3	5.3	5	0
3	20	4	7	15	1
4	45	10	17.6	40	9
5	70	16	28.1	60	22
6	95	21	36.9	85	30
7	120	22	38.7	95	31
8	145	21.5	37.8	98	31

Table 6. Results of analysis of the Charpy V-notch impact energy and percent shear plots.

	Pipe Segment C
Upper Shelf Impact Energy (Full Size), Ft-lbs	38.8
85% FATT, °F	96.8
Maxey Adjusted 85% FATT, °F	90.4

Table 7. Results of chemical analysis of a pipe steel sample from Pipe Segment A2 (failure joint) by optical emission spectroscopy (OES) removed from the joint that ruptured.

Element		Base Metal (Wt. %)
C	(Carbon)	0.287
Mn	(Manganese)	1.07
P	(Phosphorus)	0.011
S	(Sulfur)	0.029
Si	(Silicon)	0.008
Cu	(Copper)	0.023
Sn	(Tin)	0.002
Ni	(Nickel)	0.014
Cr	(Chromium)	0.015
Mo	(Molybdenum)	0.000
Al	(Aluminum)	0.002
V	(Vanadium)	0.001
Nb	(Niobium)	0.002
Zr	(Zirconium)	0.001
Ti	(Titanium)	0.001
B	(Boron)	0.0002
Ca	(Calcium)	0.0000
Co	(Cobalt)	0.003
Fe	(Iron)	Balance
Carbon Equivalent (CE_{IIW})		0.47

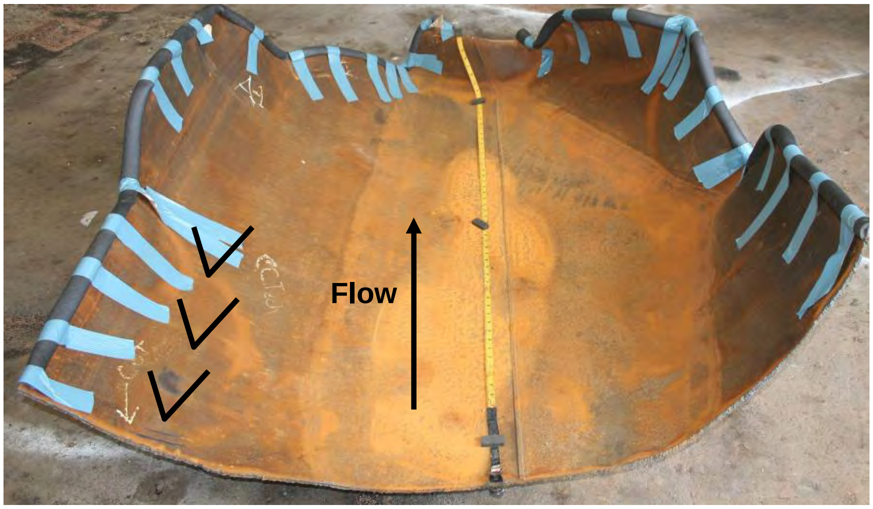


Figure 1. Photograph of Pipe Segment A1 (internal surface) in the as-received condition.

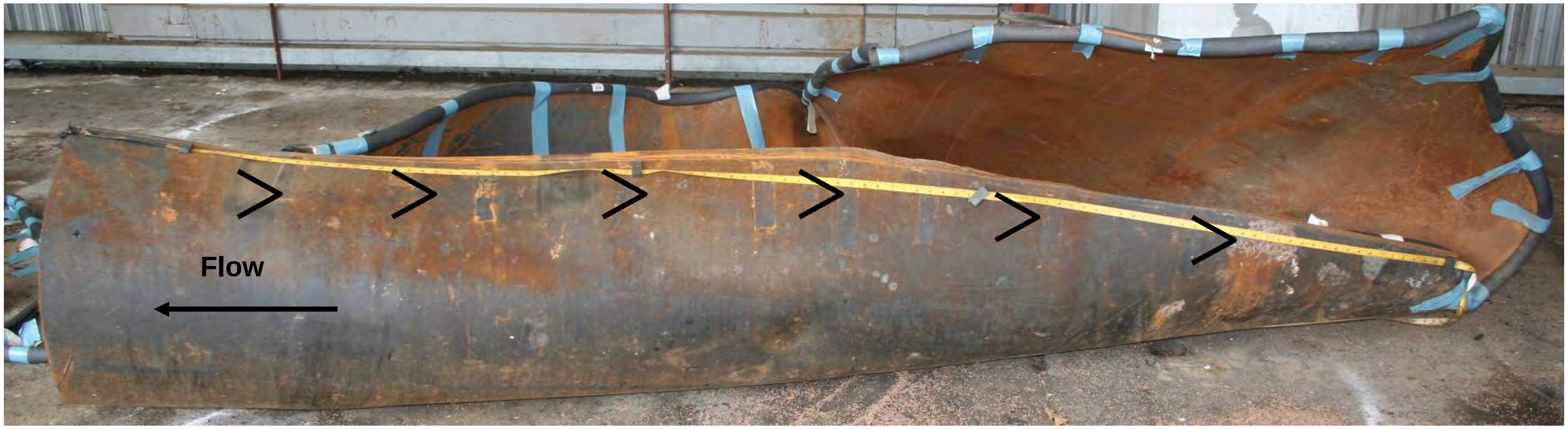


Figure 2. Photograph of Pipe Segment B1 in the as-received condition.

Figure 3. Photograph of Pipe Segment C in the as-received condition.

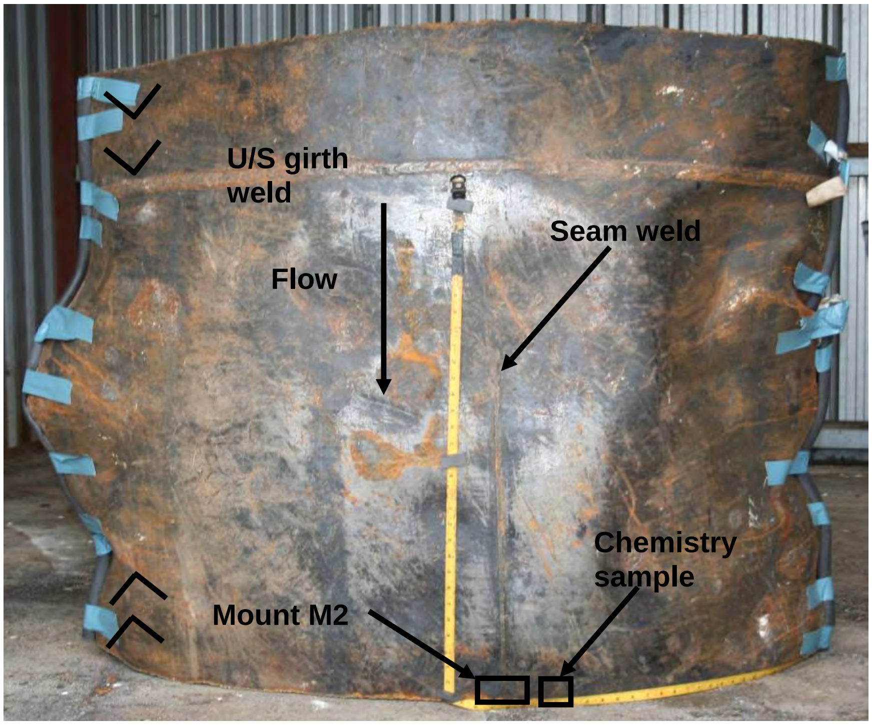


Figure 4. Photograph of Pipe Segment A2 (external surface) in the as-received condition.

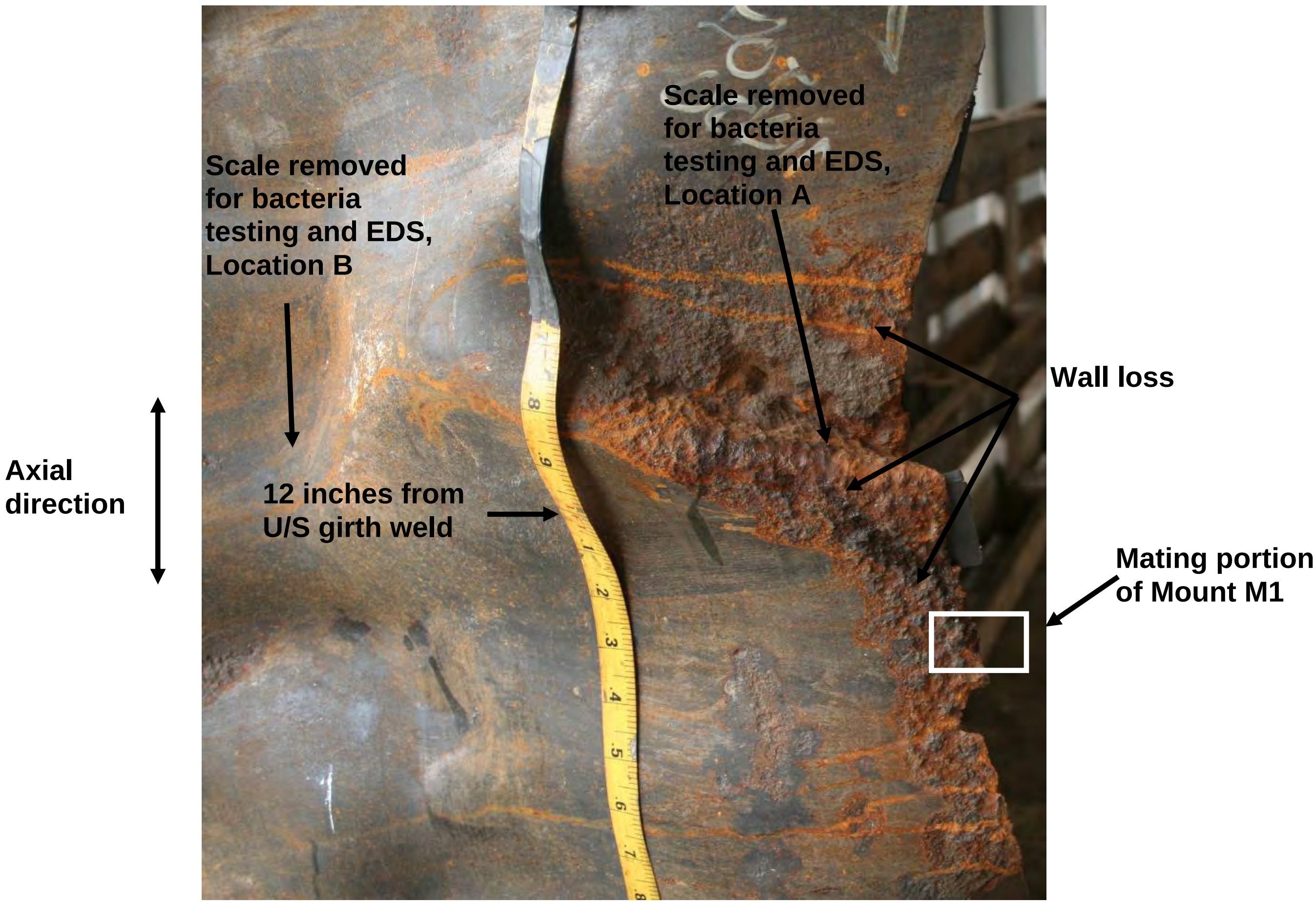


Figure 5. Photograph of the external surface of Pipe Segment A2 on the clockwise side of rupture.

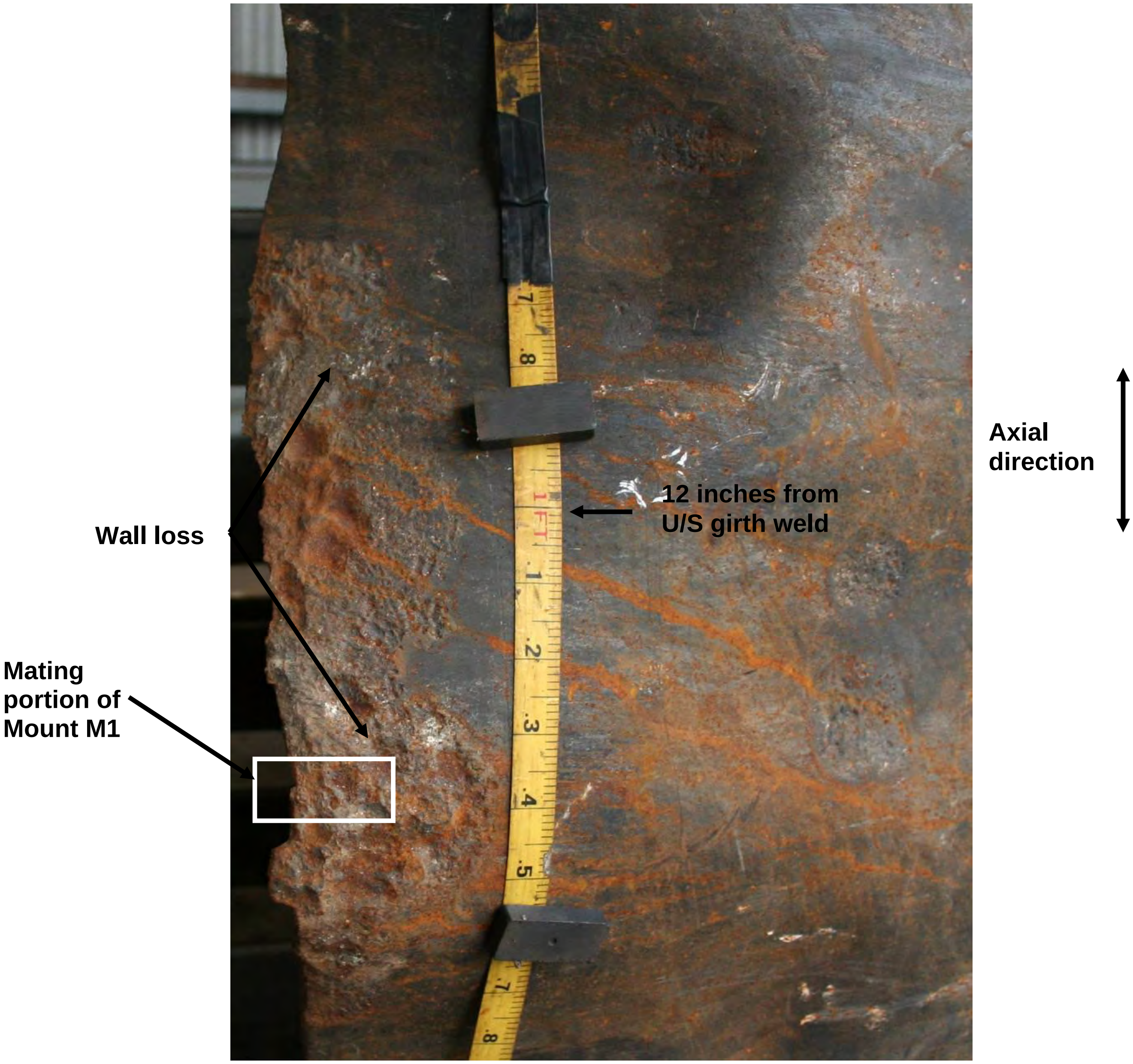


Figure 6. Photograph of the external surface of Pipe Segment A2 on the counter-clockwise side of rupture.

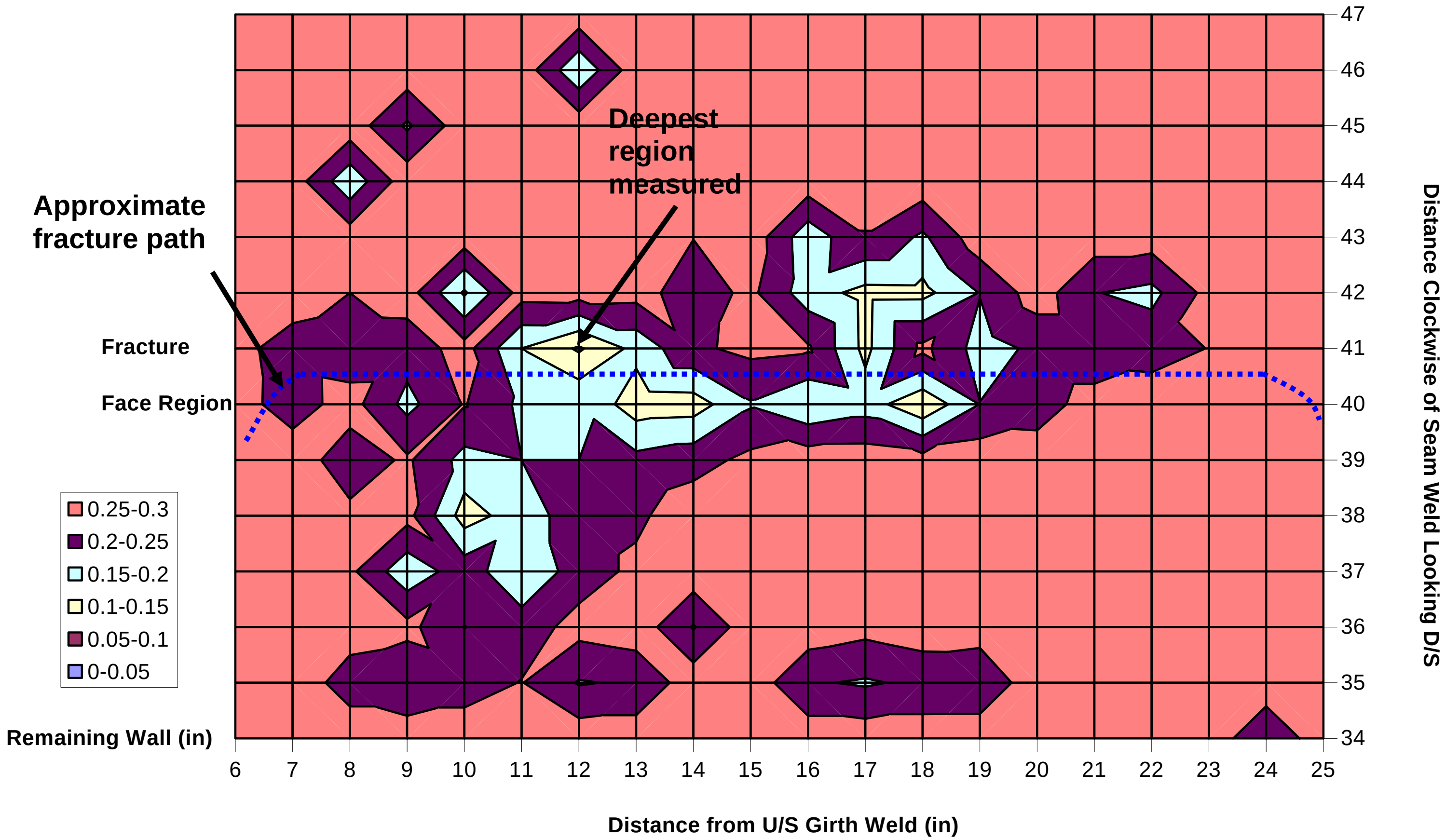


Figure 7. Remaining wall in the region of the probable failure origin.

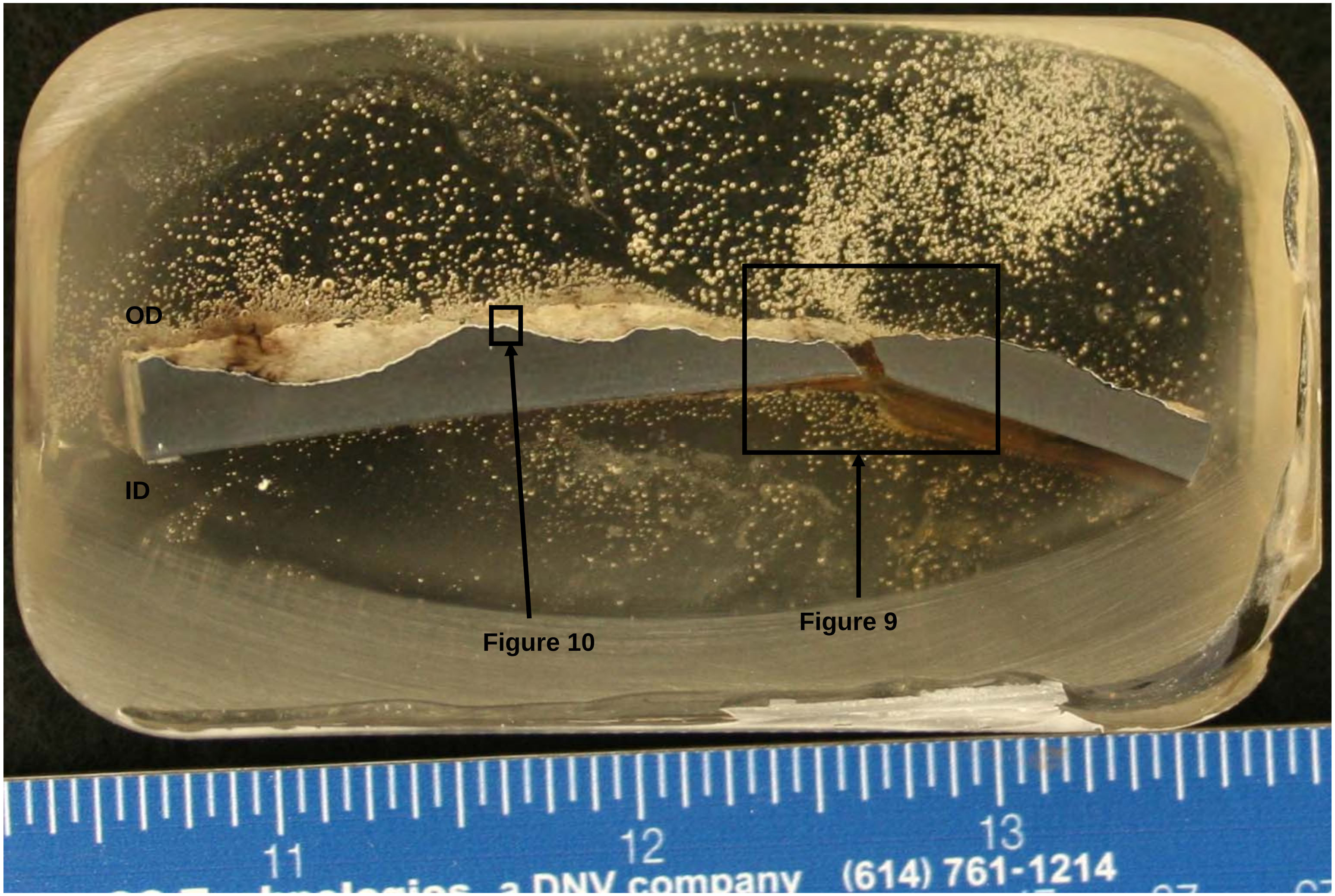


Figure 8. Stereo light photomicrograph of a transverse cross-section removed from the rupture near the failure origin (Mount M1, 4% Nital Etchant).

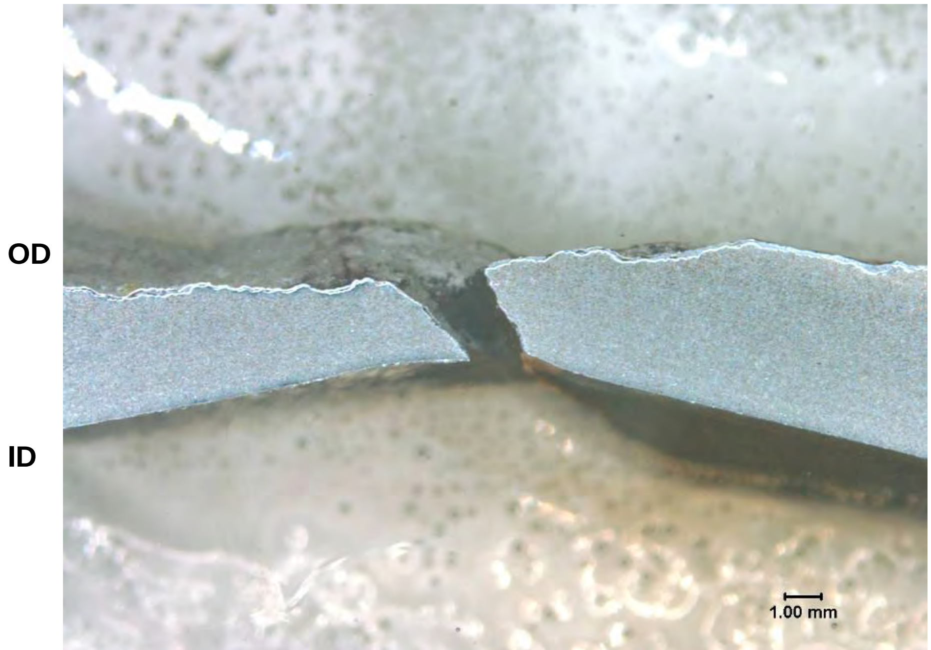


Figure 9. Stereo light photomicrograph of the rupture area indicated in Figure 8 (Mount M1, 4% Nital Etchant).

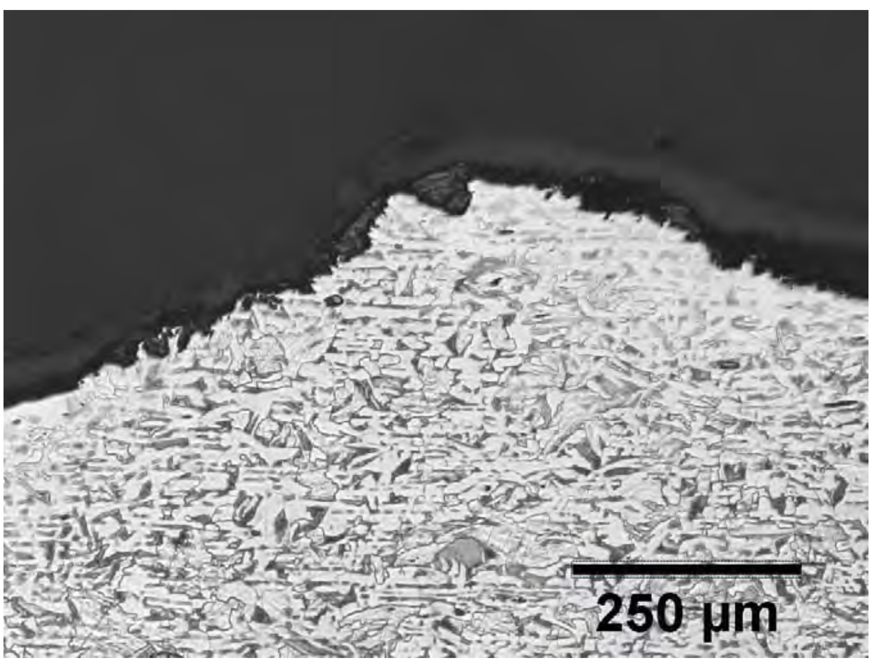


Figure 10. Light photomicrograph of the external surface of the pipe in Mount M1 (4% Nital Etchant, area indicated in Figure 8).

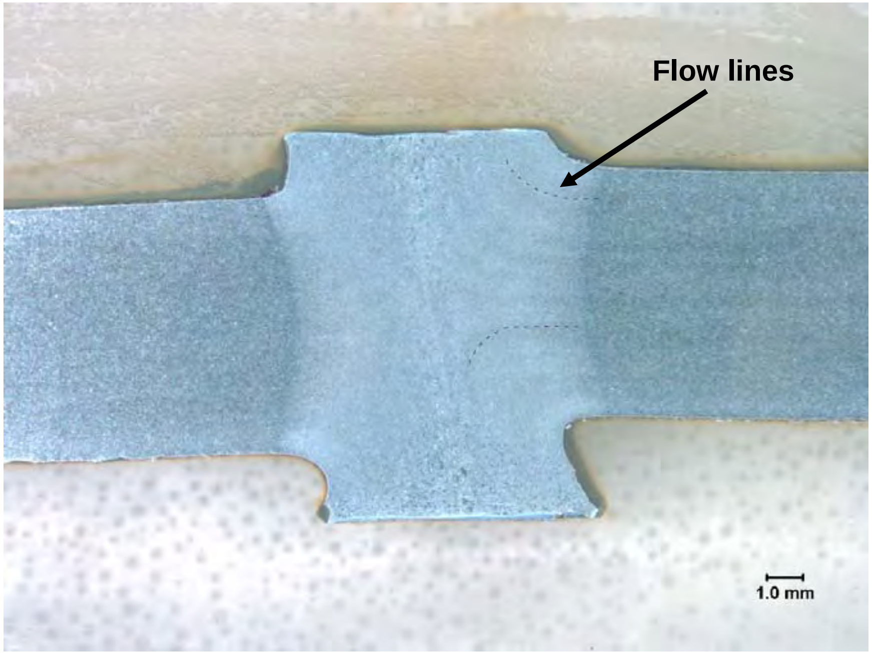


Figure 11. Stereo light photomicrograph of the seam weld cross-section (Mount M2, 4% Nital Etchant).

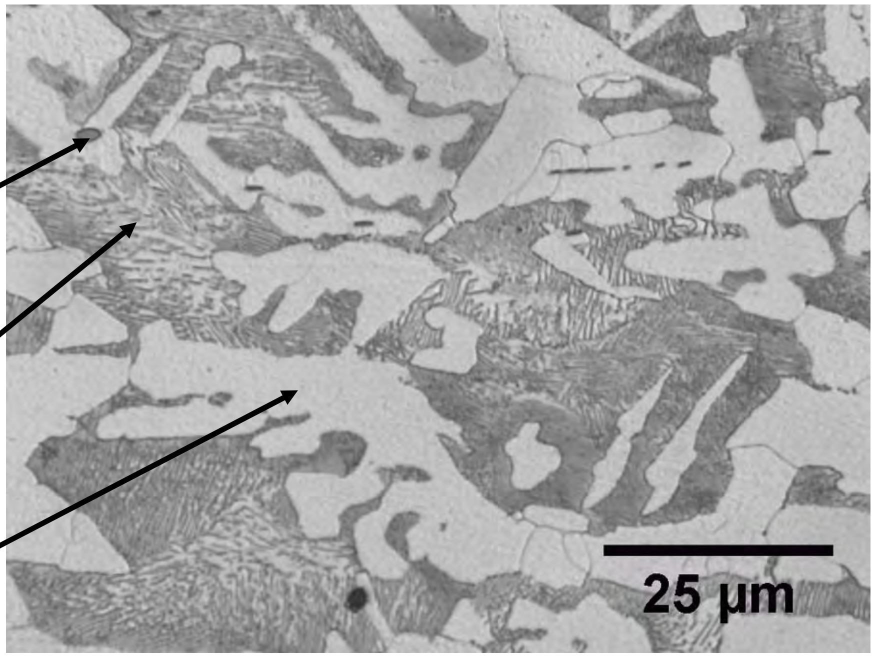


Figure 12. Light photomicrograph of the typical base metal microstructure from Mount M2 (4% Nital Etchant).

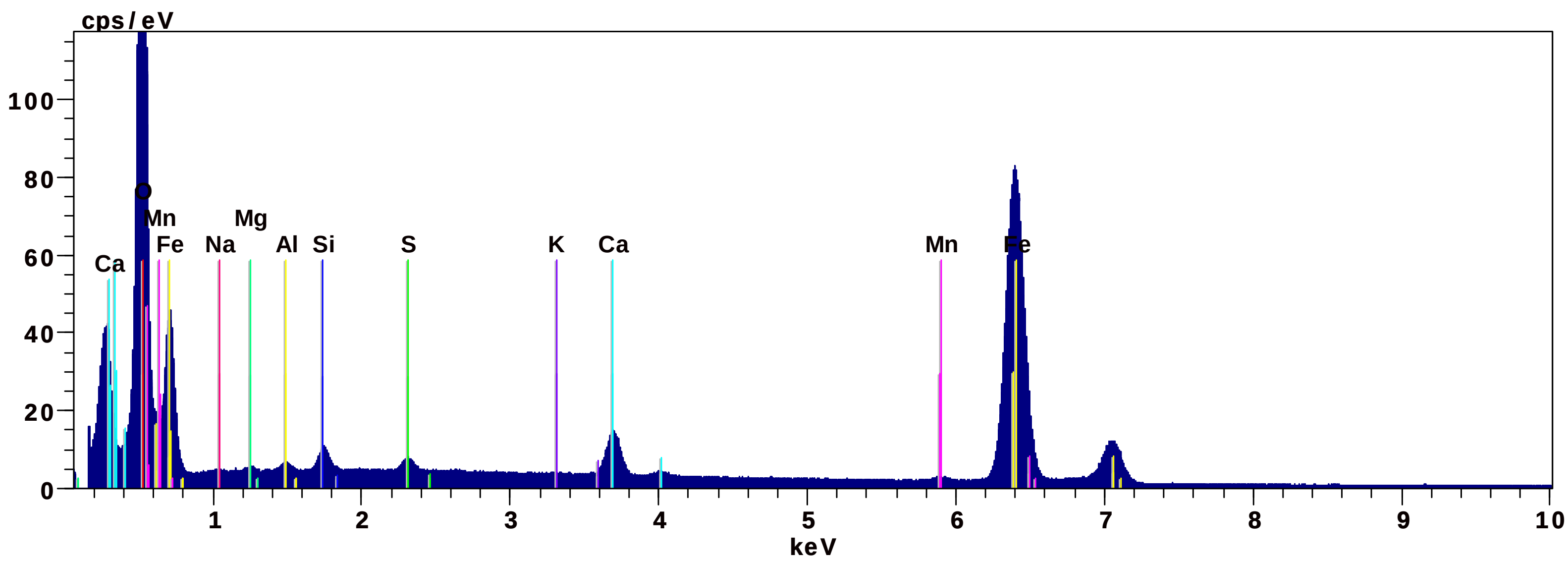


Figure 13. EDS spectrum of scale that was removed from the external surface.

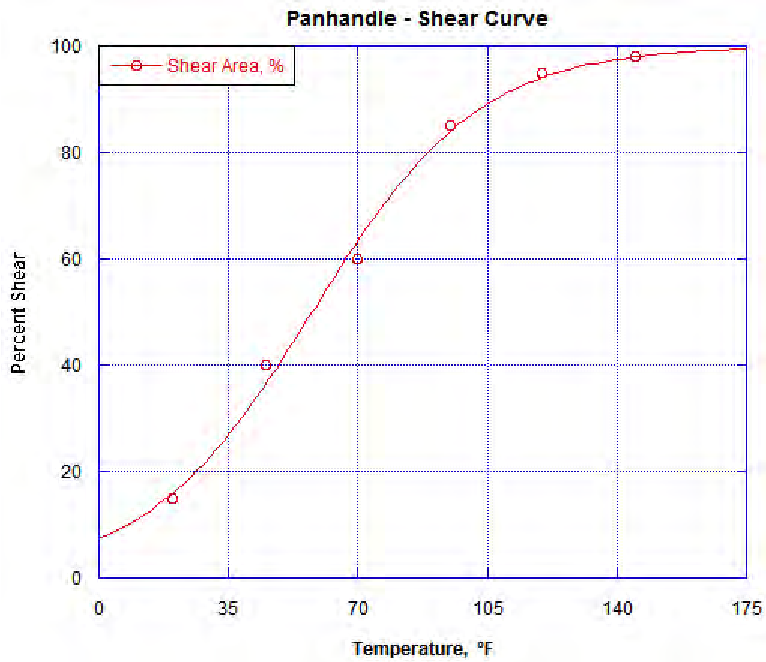


Figure 14. Plot of percent shear from Charpy V-notch tests as a function of temperature for samples removed from Pipe Segment C.

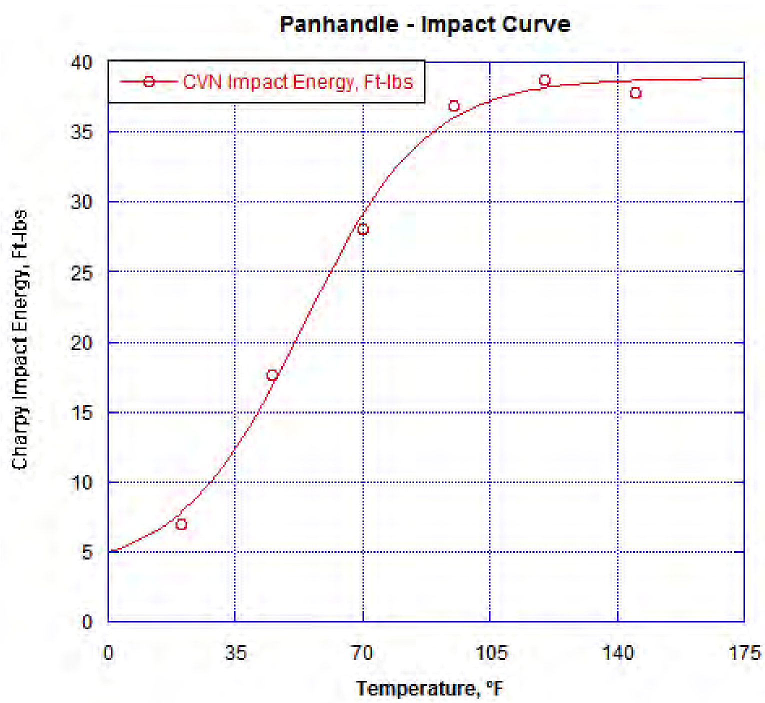


Figure 15. Plot of Charpy V-notch impact energy as a function of temperature for samples removed from Pipe Segment C.

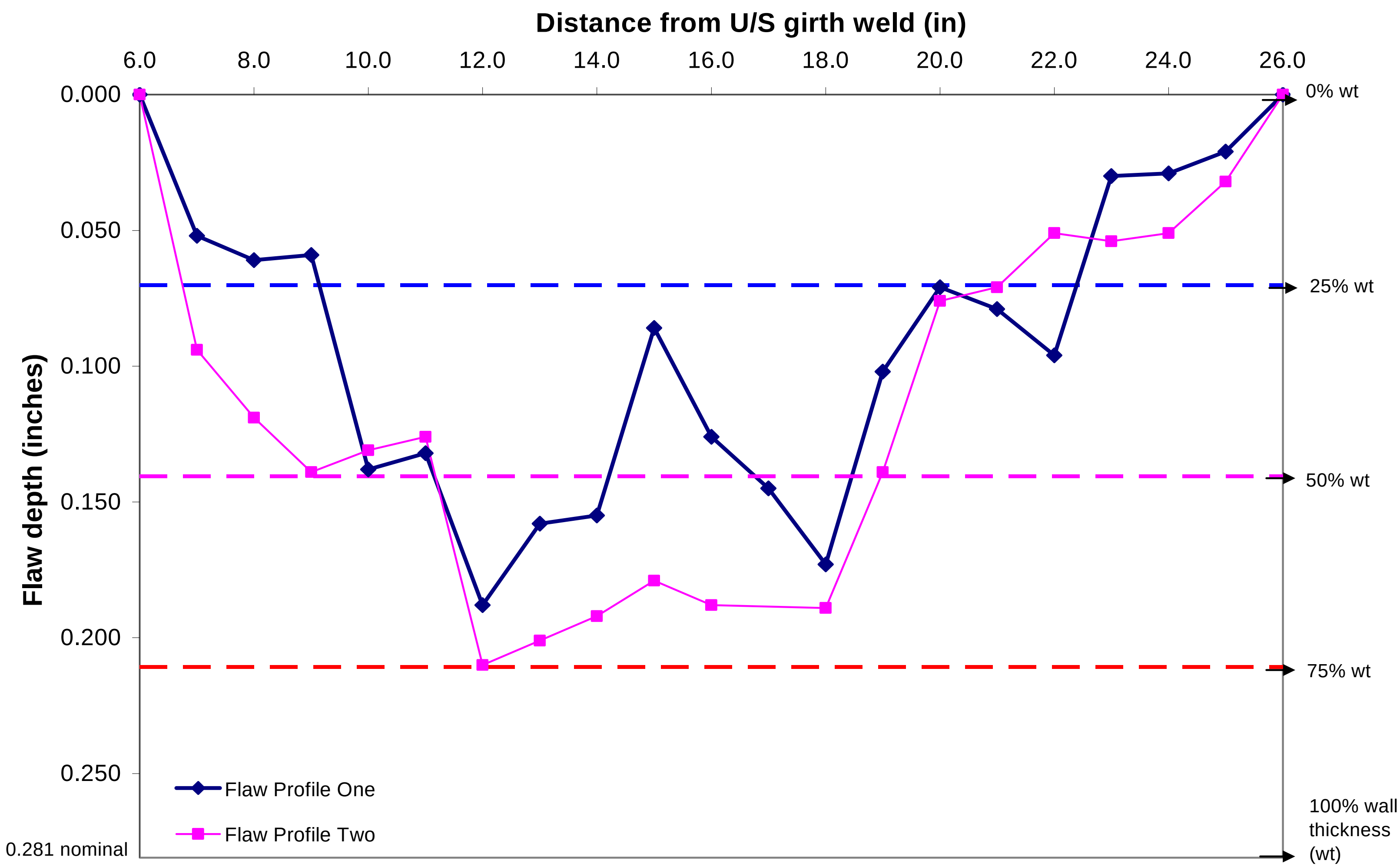


Figure 16. Flaw depth vs. length profile of the measured flaws.

APPENDIX A

DESCRIPTION OF CORLAS^{TM}

APPENDIX A

Description of CorLAS™

The CorLAS™ computer program was developed by CC Technologies to evaluate crack-like flaws in pipelines based on inelastic fracture mechanics. Using the effective area of the actual, measured crack length-depth profile, an equivalent semi-elliptical surface flaw is modeled and used to compute the effective stress and the applied value of J for internal pressure loading. The effective stress and applied J are then compared with the flow strength (σ_{fs}) and fracture toughness (J_C), respectively, to predict the failure pressure.

The program also contains a similar inelastic fracture mechanics analysis for through-wall flaws. The fracture toughness of the steel can be estimated from Charpy data or measured by means of a J_{IC} test. In the most recent version of CorLAS™, the fracture toughness analysis automatically checks for plastic instability and only the fracture toughness curve needs to be considered for crack-like flaws. The actual tensile and Charpy properties of the pipe joint, measured from the samples removed, can be used for the critical leak/rupture length calculation.

```
********************************************************************************
Houstonia 200                    :SEMI-ELLIPTICAL FLAW PROFILE
EST YS 48 ksi

UTS, psi =  71500.  YS, psi =  51750.  FS, psi =  61750.
E, ksi = 29500.  nexp = 0.110  Jc, lb/in =  1935.
Thin-wall (OD) formula for hoop stress   Tmat =   62.5
OD, in. =   24.00  Wall Thickness, in. =  0.281

SUMMARY OF RESULTS FOR EFFECTIVE-AREA METHOD
Flaw: Start, in. =     4.000 Length, in. =     9.000 Area, in.^2 =    1.283
  Depth,in.: Maximum =  0.188  Equivalent Flaw =  0.182
Failure Stress, psi =  37048.  Failure Pressure, psig =  867.53

******** Input Flaw Profile Data *********
```

---------- Length, in. ----------	---------- Depth, in. ----------
0	0
1	0.052
2	0.061
3	0.059
4	0.138
5	0.132
6	0.188
7	0.158
8	0.155

9	0.086
10	0.126
11	0.145
12	0.173
13	0.102
15	0.071
16	0.079
17	0.096
18	0.03
19	0.029
20	0.021
21	0
----------	----------

******** Effective Flaw Results *********

i	Flaw Start, in.	Flaw Length, in.	Effective Area, in.^2	Flow Failure Stress, psi	Japplied, lb/in	Tapplied	Failure Pressure, psig
THOSE BELOW ARE FOR FLOW-STRENGTH FAILURE CRITERION							
1	4	9	1.283	37048	4278.6	1794.1	867.5
----------	----------	----------	----------	----------	----------	----------	----------

****

Houstonia 200 :SEMI-ELLIPTICAL FLAW PROFILE
EST YS 48 ksi
UTS, psi = 71500. YS, psi = 51750. FS, psi = 61750.
E, ksi = 29500. nexp = 0.110 Jc, lb/in = 1935.
Thin-wall (OD) formula for hoop stress Tmat = 62.5
OD, in. = 24.00 Wall Thickness, in. = 0.281

SUMMARY OF RESULTS FOR EFFECTIVE-AREA METHOD
Flaw: Start, in. = 5.000 Length, in. = 8.000 Area, in.^2 = 1.480
Depth,in.: Maximum = 0.210 Equivalent Flaw = 0.236
Failure Stress, psi = 28328. Failure Pressure, psig = 663.34

******** Input Flaw Profile Data *********

Length, in.	Depth, in.
0	0
1	0.094
2	0.119
3	0.139
4	0.131
5	0.126

6	0.21
7	0.201
8	0.192
9	0.179
10	0.188
12	0.189
13	0.139
15	0.076
16	0.071
17	0.051
18	0.054
19	0.051
20	0.032
21	0
----------	----------

******** Effective Flaw Results *********

i	Flaw Start, in.	Flaw Length, in.	Effective Area, in.^2	Flow Failure Stress, psi	Japplied, lb/in	Tapplied	Failure Pressure, psig
THOSE BELOW ARE FOR FLOW-STRENGTH FAILURE CRITERION							
1	5	8	1.48	28328	10025.2	6519.7	663.3

CC Technologies / Det Norske Veritas

CCT/DNV is a leading provider of technology in managing corrosion and materials risks. As one of the few firms to combine practical engineering solutions with state-of-the-art research and testing, we can offer our clients innovative, cost effective solutions. We specialize in engineering, research and testing for corrosion control and monitoring, fitness-for-service, pipeline/plant integrity analysis, materials evaluation and selection, failure analysis, litigation support, management systems approaches and instrumentation and software design and development.

CC Technologies
a DNV company

MANAGING RISK DNV

Appendix D

Panhandle Close Interval Survey

CLOSE INTERVAL POTENTIAL SURVEY

LINE 200 24 INCH 2 GATE TO 3 GATE

FROM

EAST EDGE RIVER

TO

TS 24.4

FOR

CMS PANHANDLE EASTERN

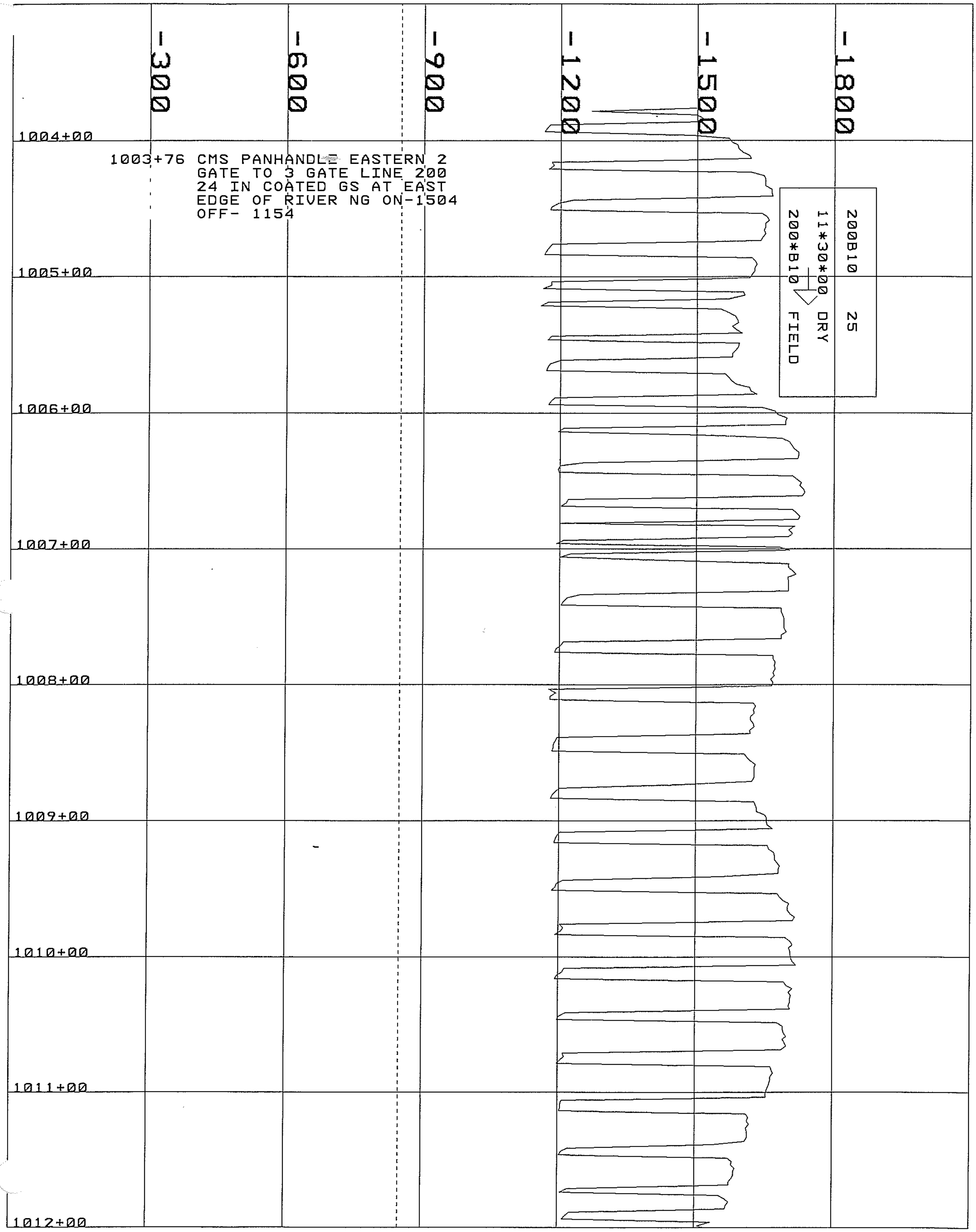
BY

CORRPRO COMPANIES, INC.

HOUSTON, TEXAS

NOVEMBER, 2000

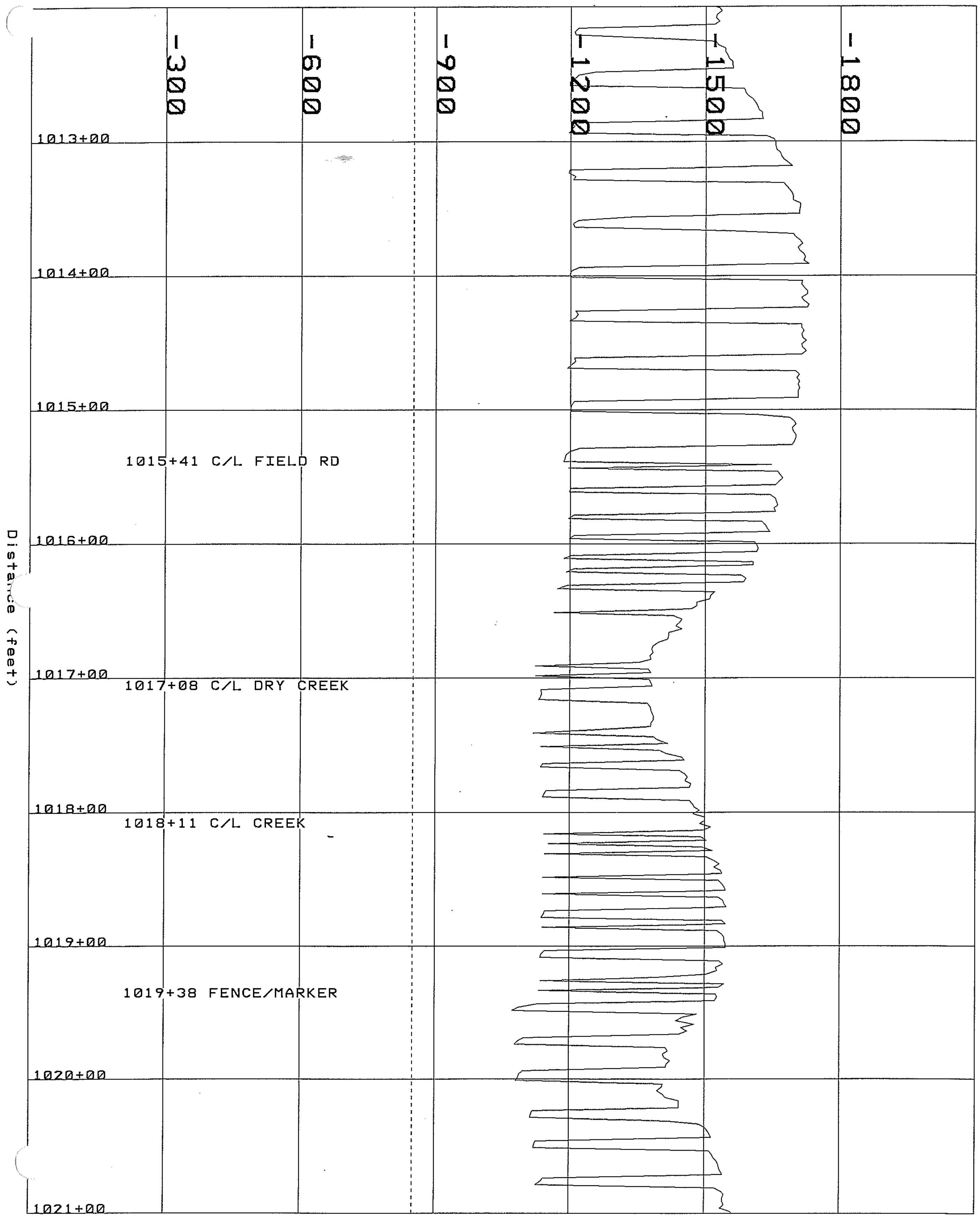
Pipe/Soil Potential (mv)

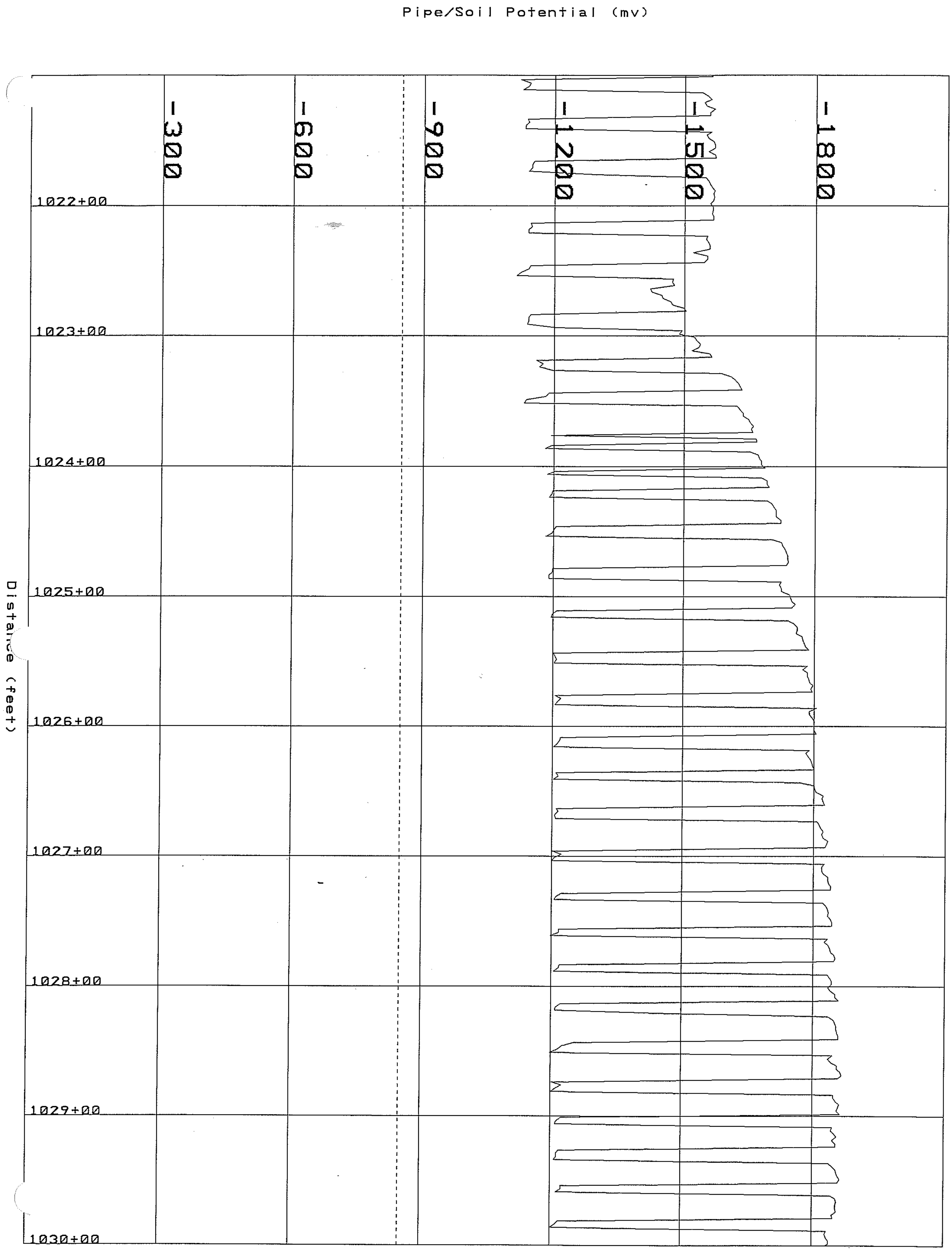


Distance (feet)

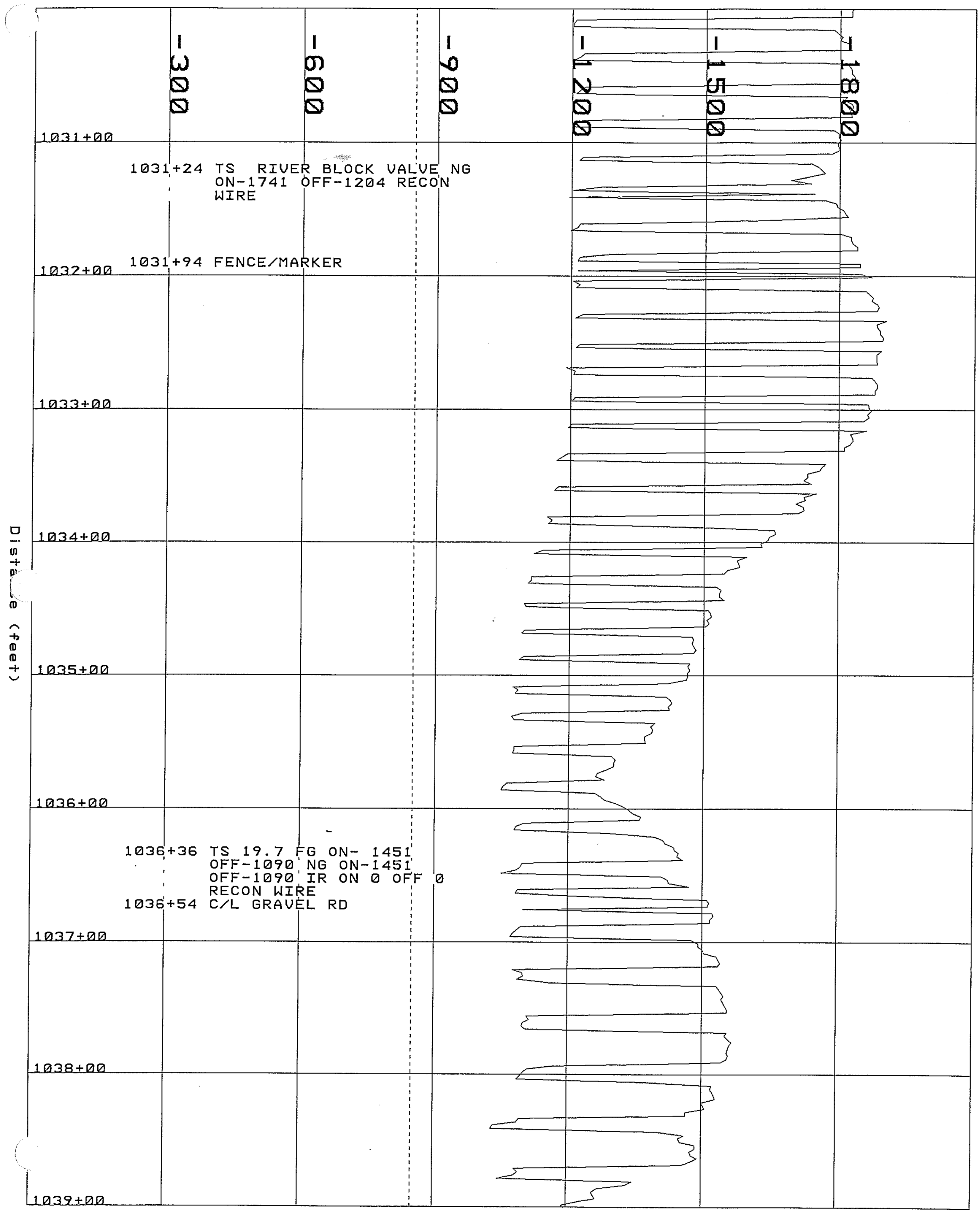
1

Pipe/Soil Potential (mv)

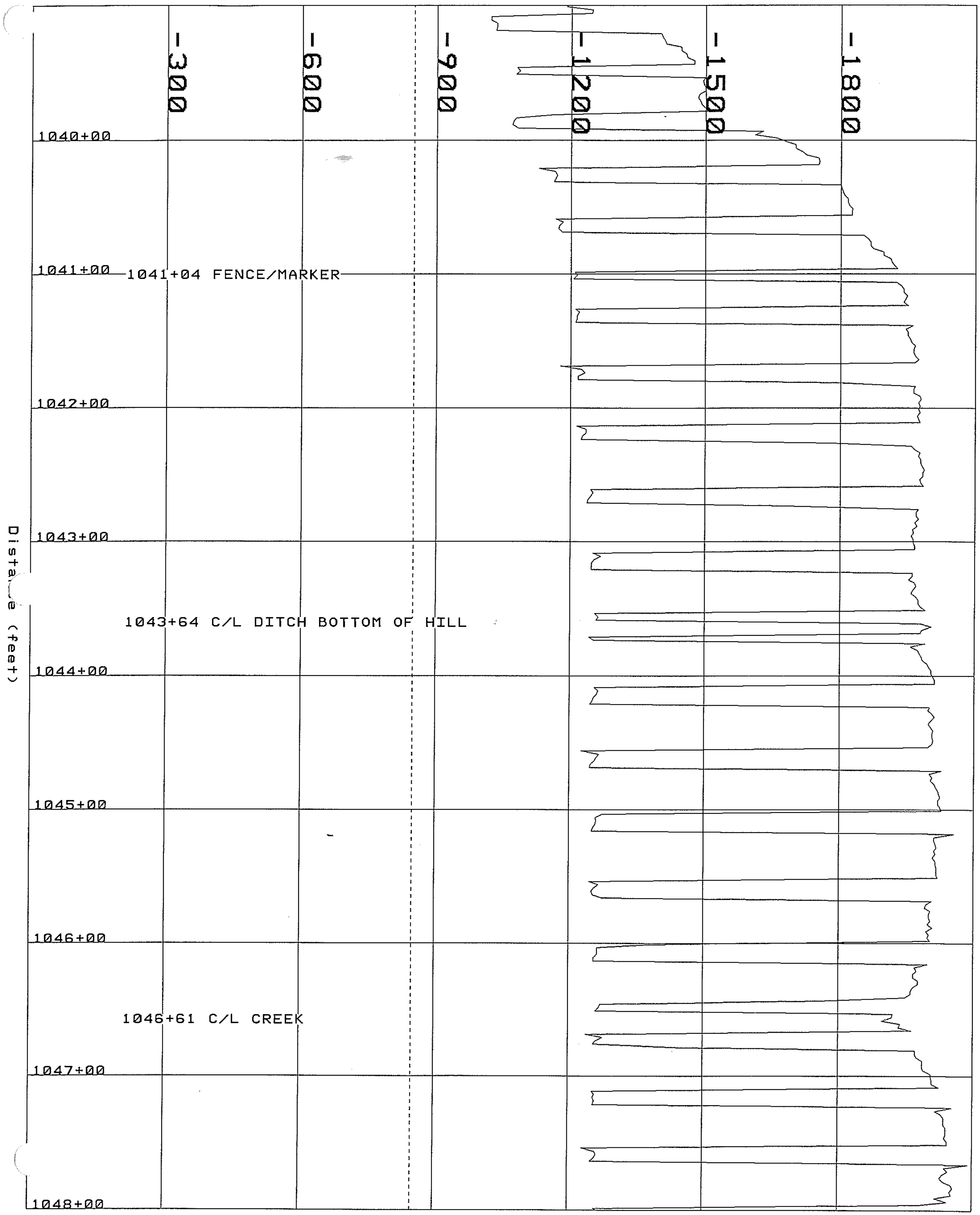


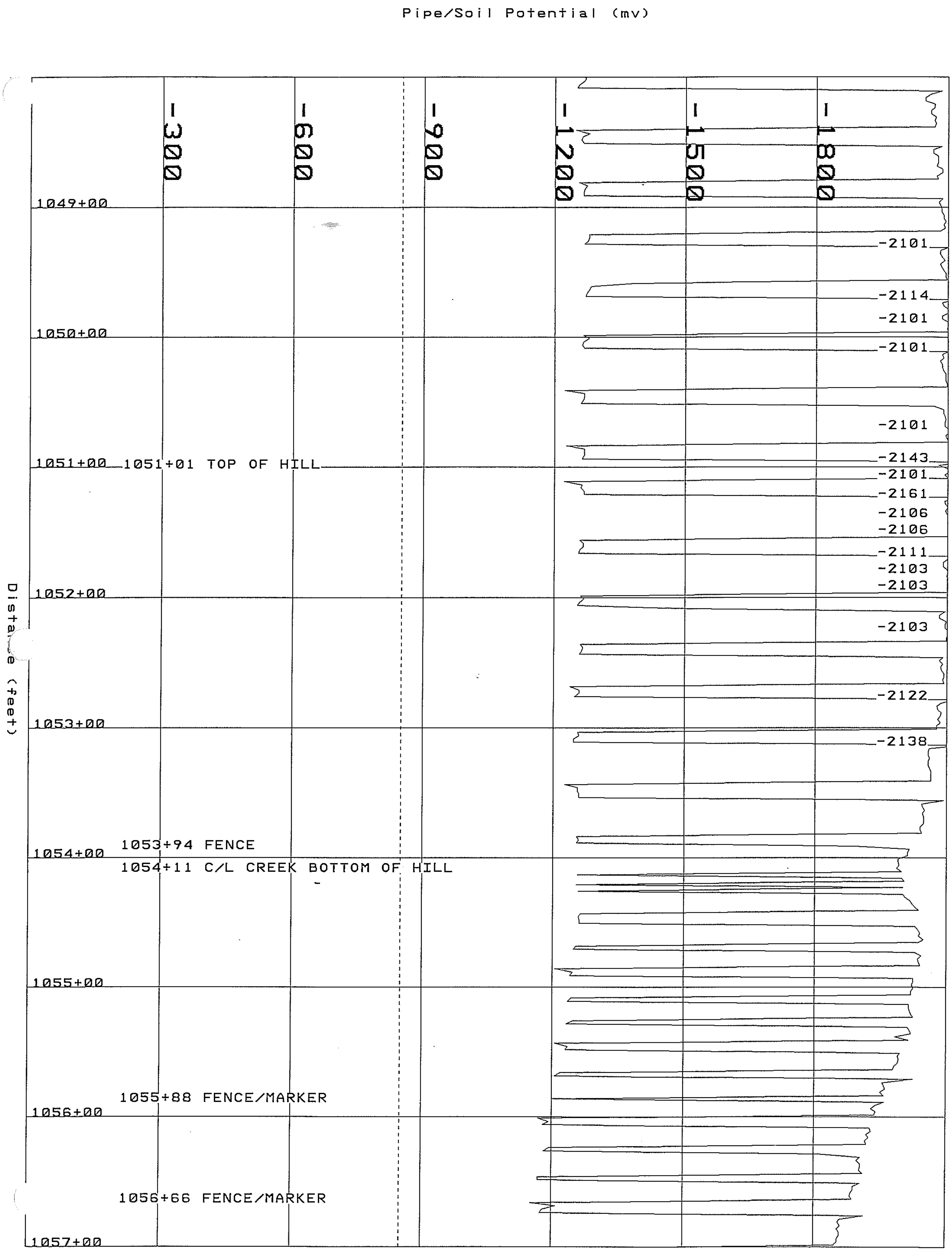

Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
1022+00
1023+00
1024+00
1025+00
1026+00
1027+00
1028+00
1029+00
1030+00
Distance (feet)

Pipe/Soil Potential (mv)

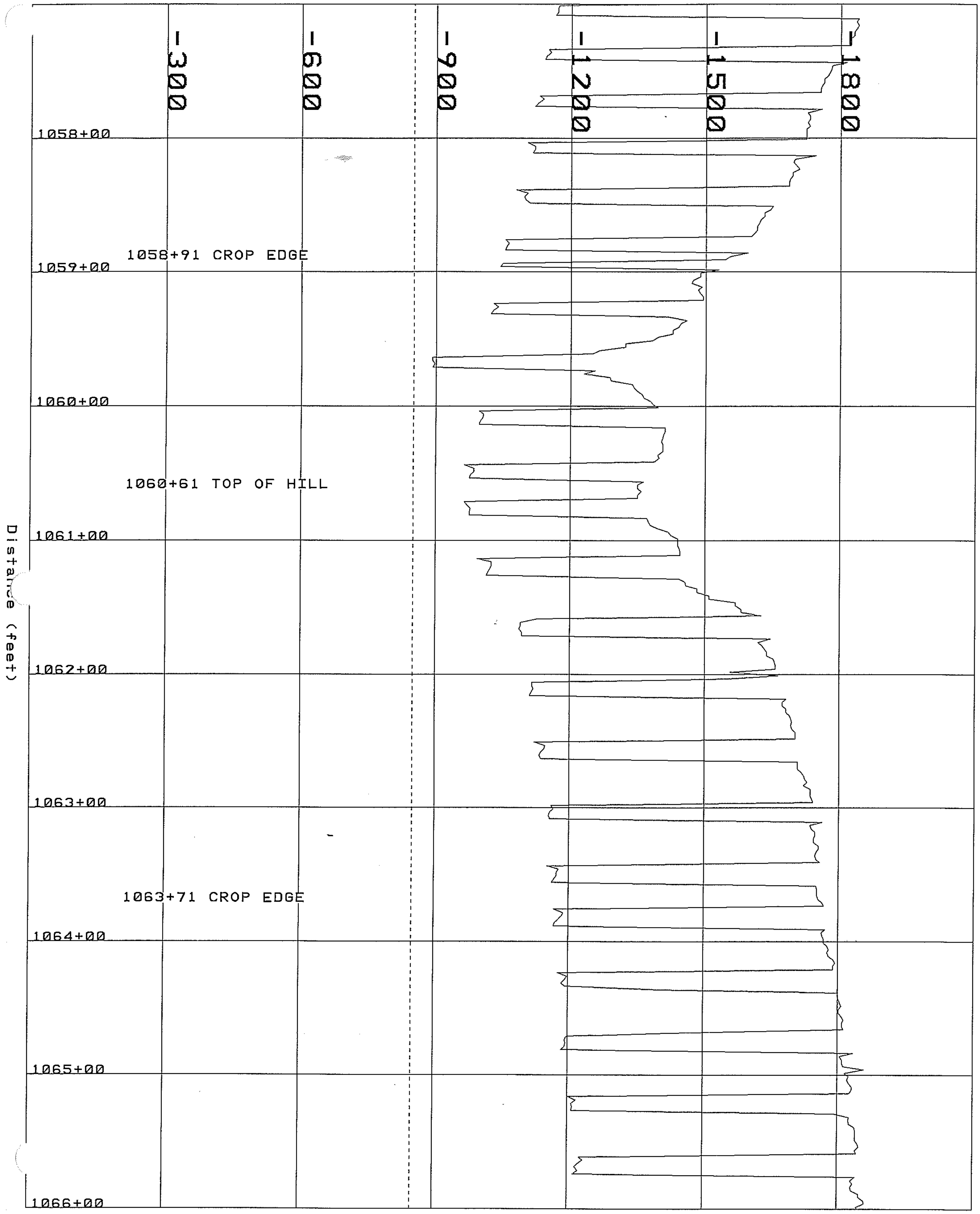


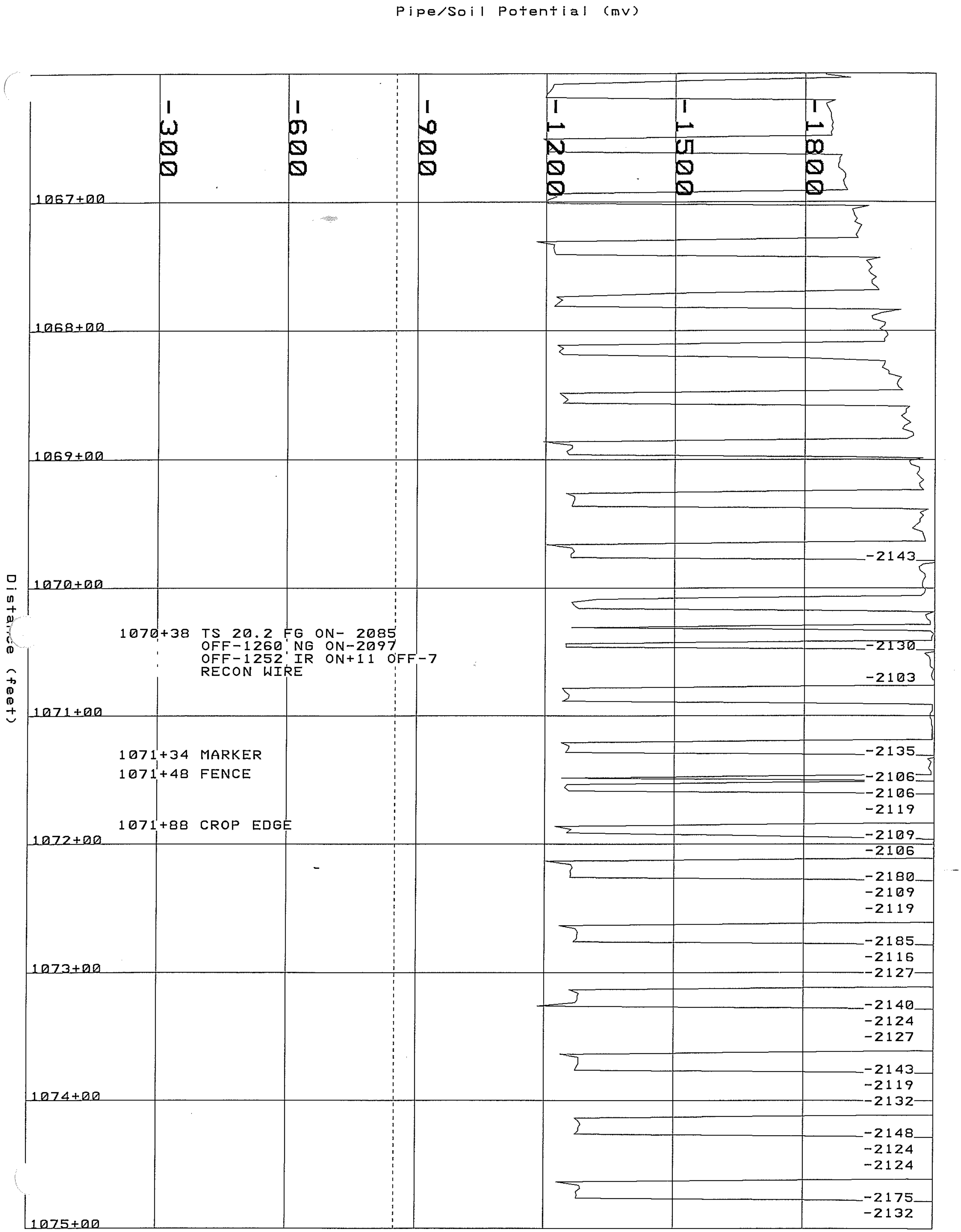
Pipe/Soil Potential (mv)



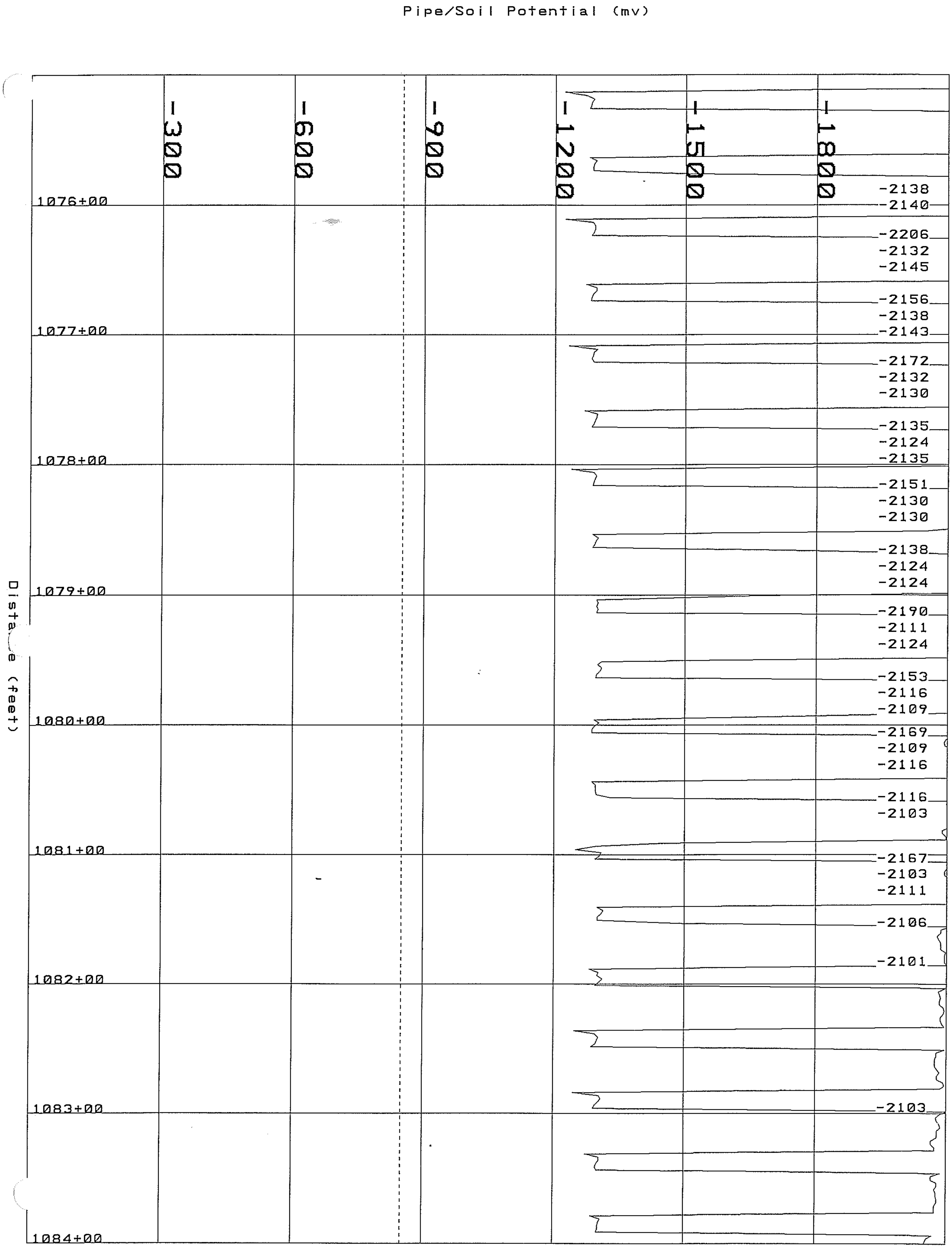

Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1049+00
1050+00
1051+00
1052+00
1053+00
1054+00
1055+00
1056+00
1057+00
1051+01 TOP OF HILL
1053+94 FENCE
1054+11 C/L CREEK BOTTOM OF HILL
1055+88 FENCE/MARKER
1056+66 FENCE/MARKER
-2101
-2114
-2101
-2101
-2101
-2143
-2101
-2161
-2106
-2106
-2111
-2103
-2103
-2103
-2122
-2138

Pipe/Soil Potential (mv)



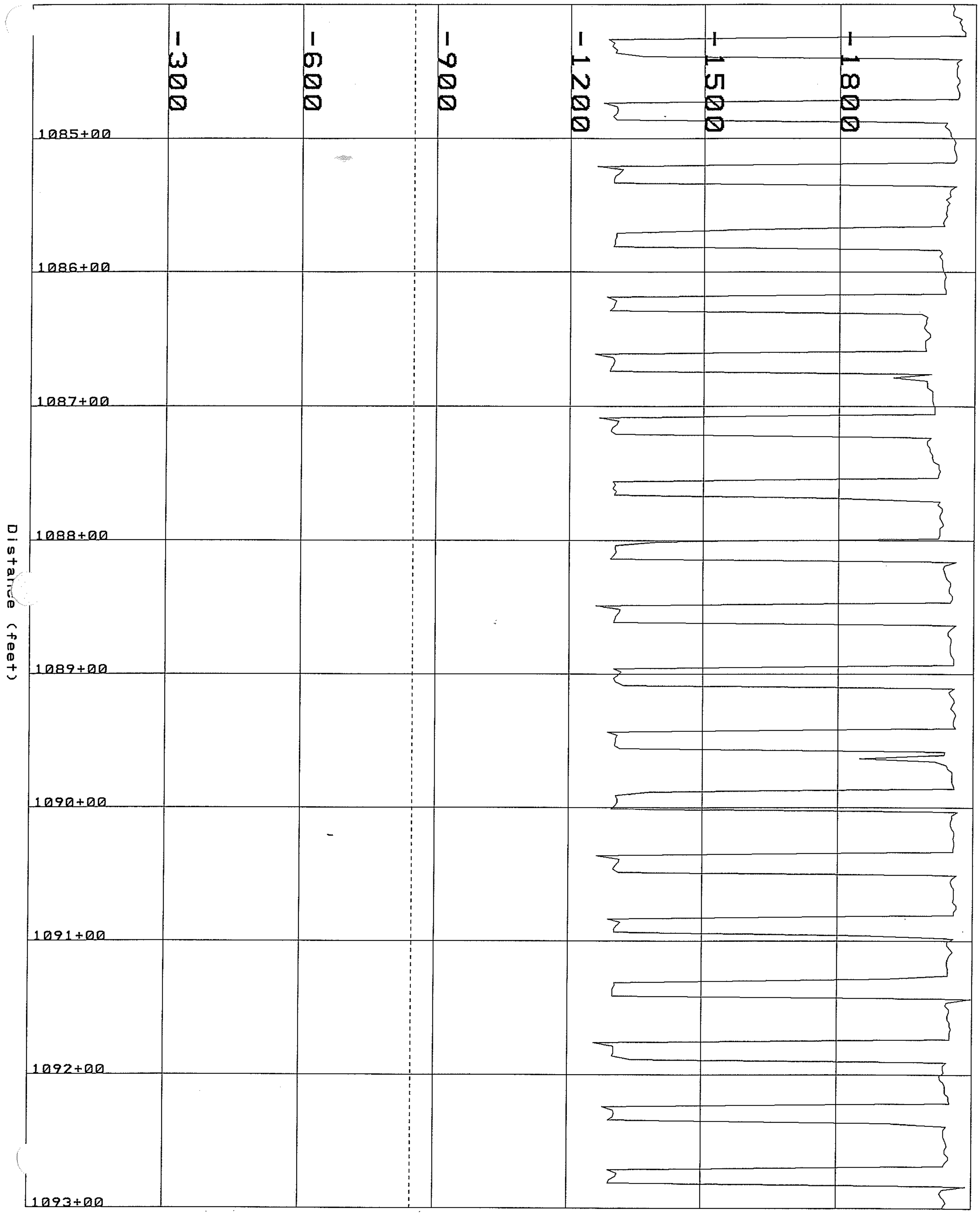


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
1067+00
1068+00
1069+00
-2143
1070+00
1070+38 TS 20.2 FG ON- 2085
OFF-1260 NG ON-2097
OFF-1252 IR ON+11 OFF-7
RECON WIRE
-2130
-2103
1071+00
1071+34 MARKER
-2135
1071+48 FENCE
-2106
-2106
-2119
1071+88 CROP EDGE
-2109
1072+00
-2106
-2180
-2109
-2119
-2185
-2116
1073+00
-2127
-2140
-2124
-2127
-2143
-2119
1074+00
-2132
-2148
-2124
-2124
-2175
-2132
1075+00
Distance (feet)

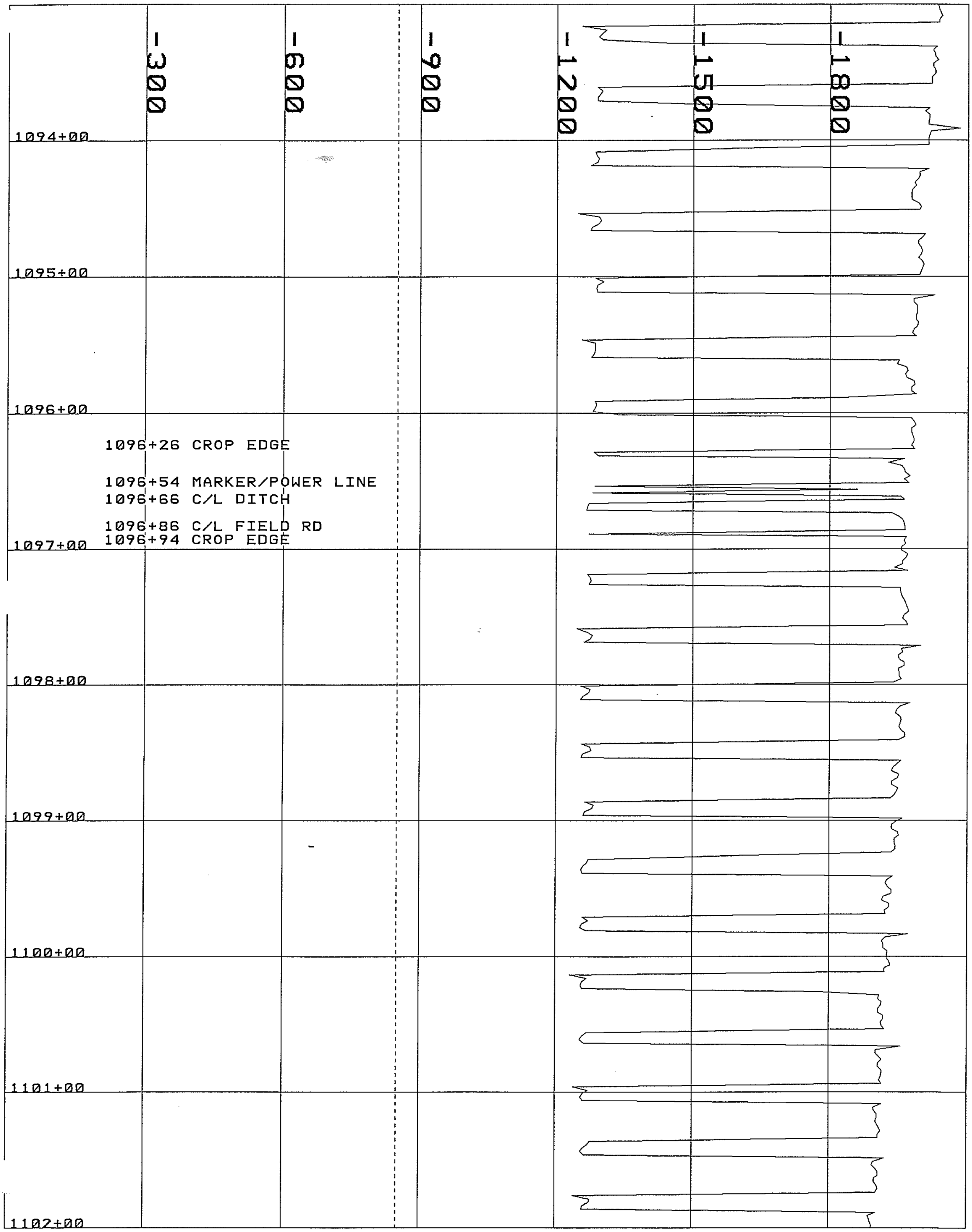


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1076+00
1077+00
1078+00
1079+00
1080+00
1081+00
1082+00
1083+00
1084+00
-2138
-2140
-2206
-2132
-2145
-2156
-2138
-2143
-2172
-2132
-2130
-2135
-2124
-2135
-2151
-2130
-2130
-2138
-2124
-2124
-2190
-2111
-2124
-2153
-2116
-2109
-2169
-2109
-2116
-2116
-2103
-2167
-2103
-2111
-2106
-2101
-2103

Pipe/Soil Potential (mv)

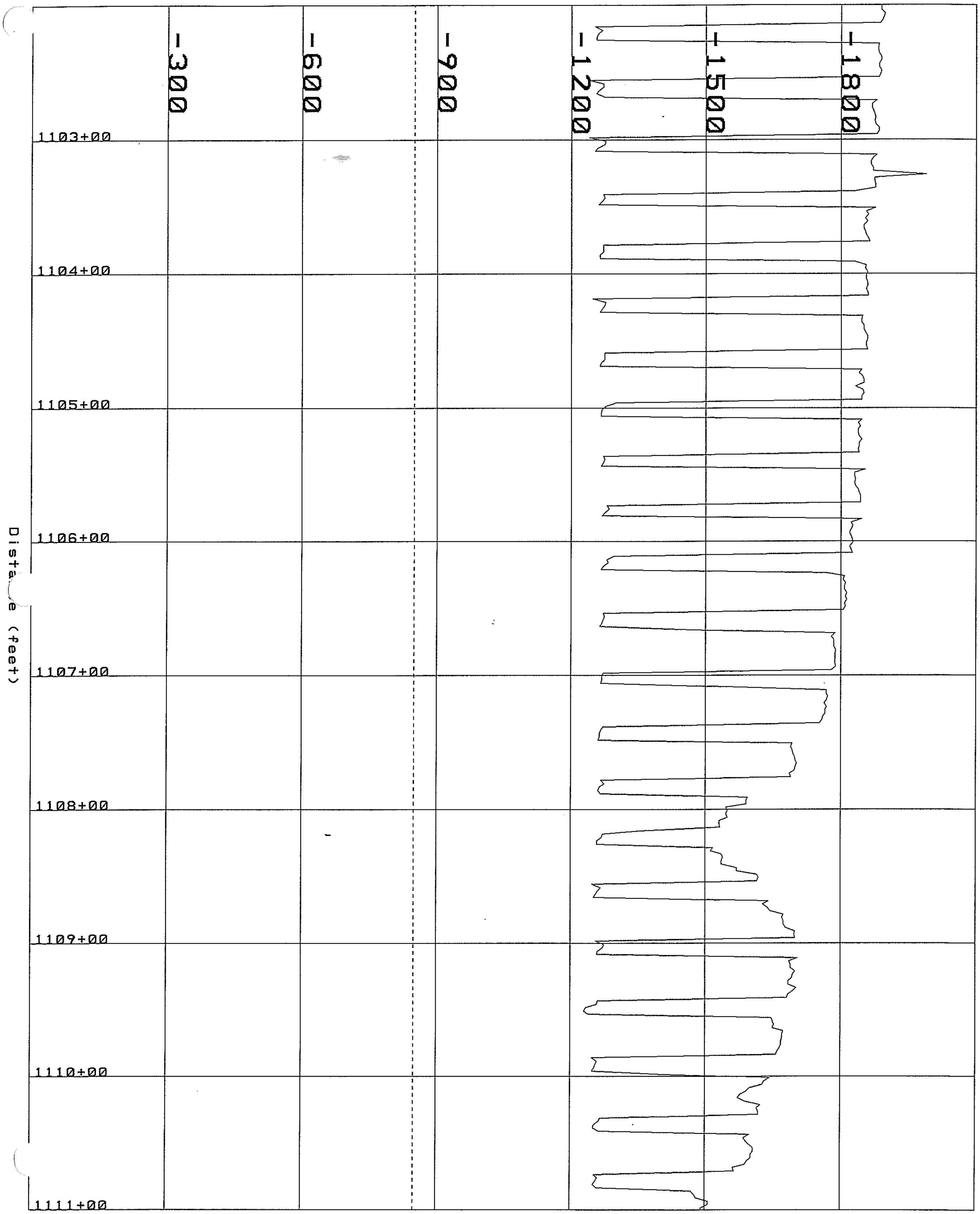


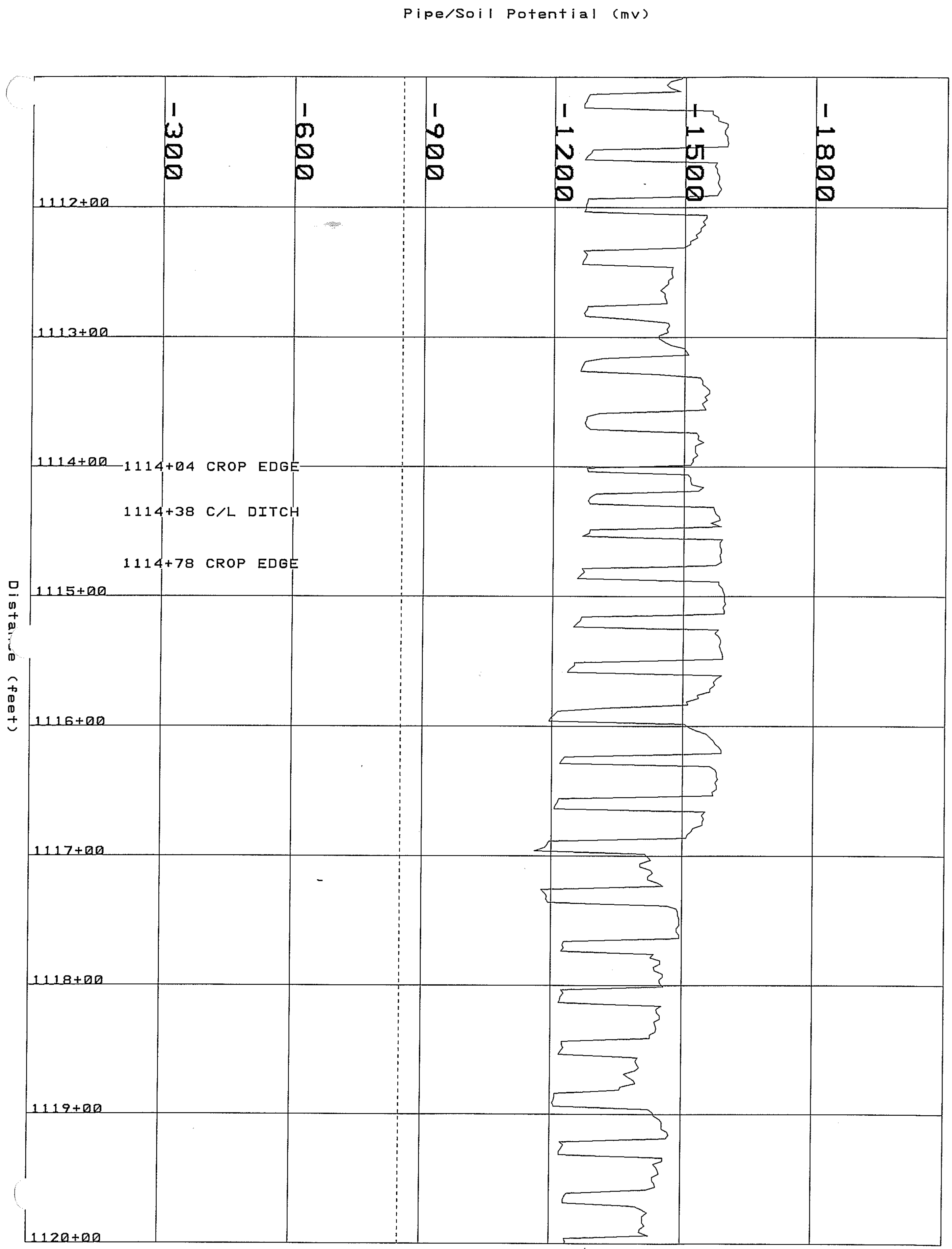
Pipe/Soil Potential (mv)

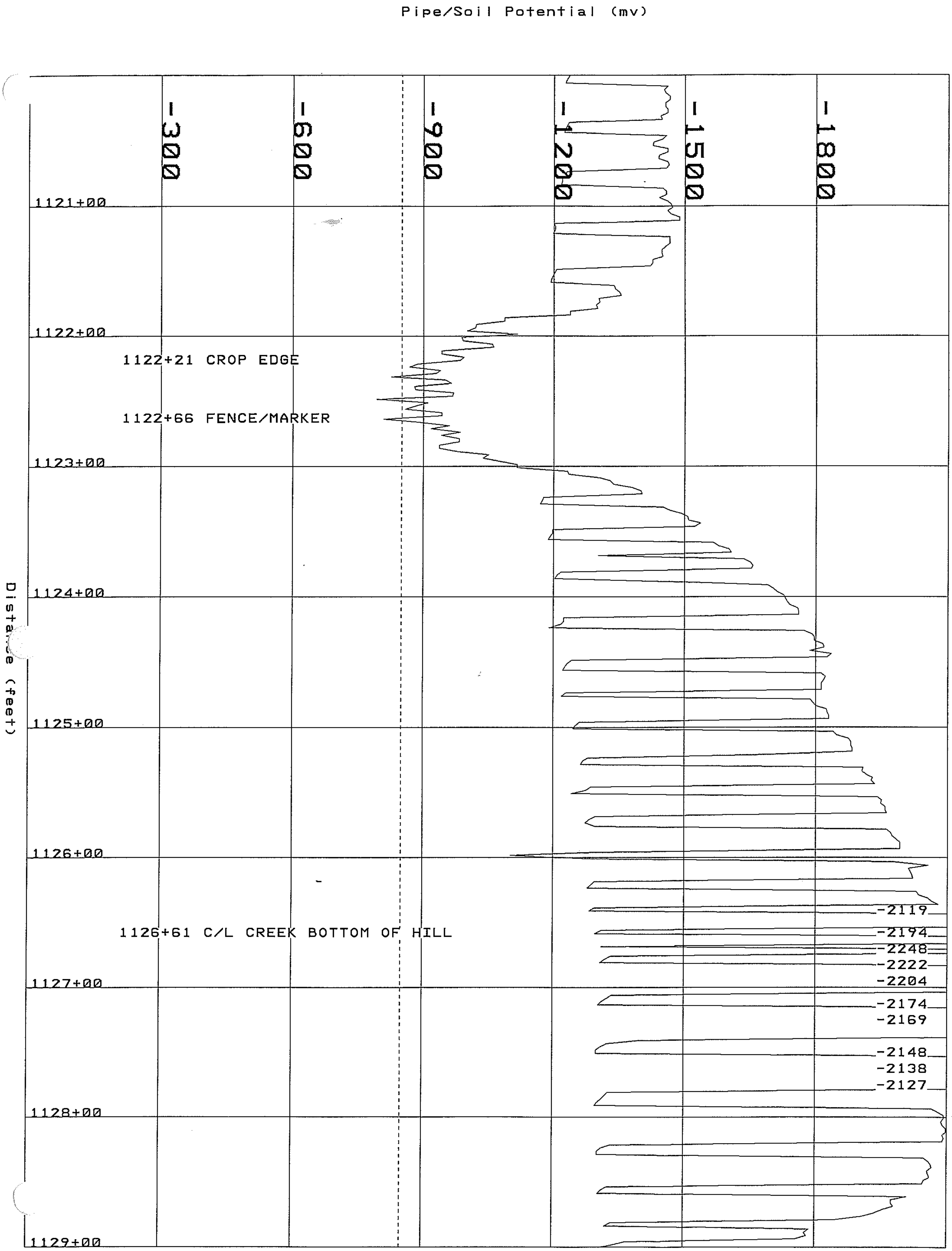


Distance (feet)

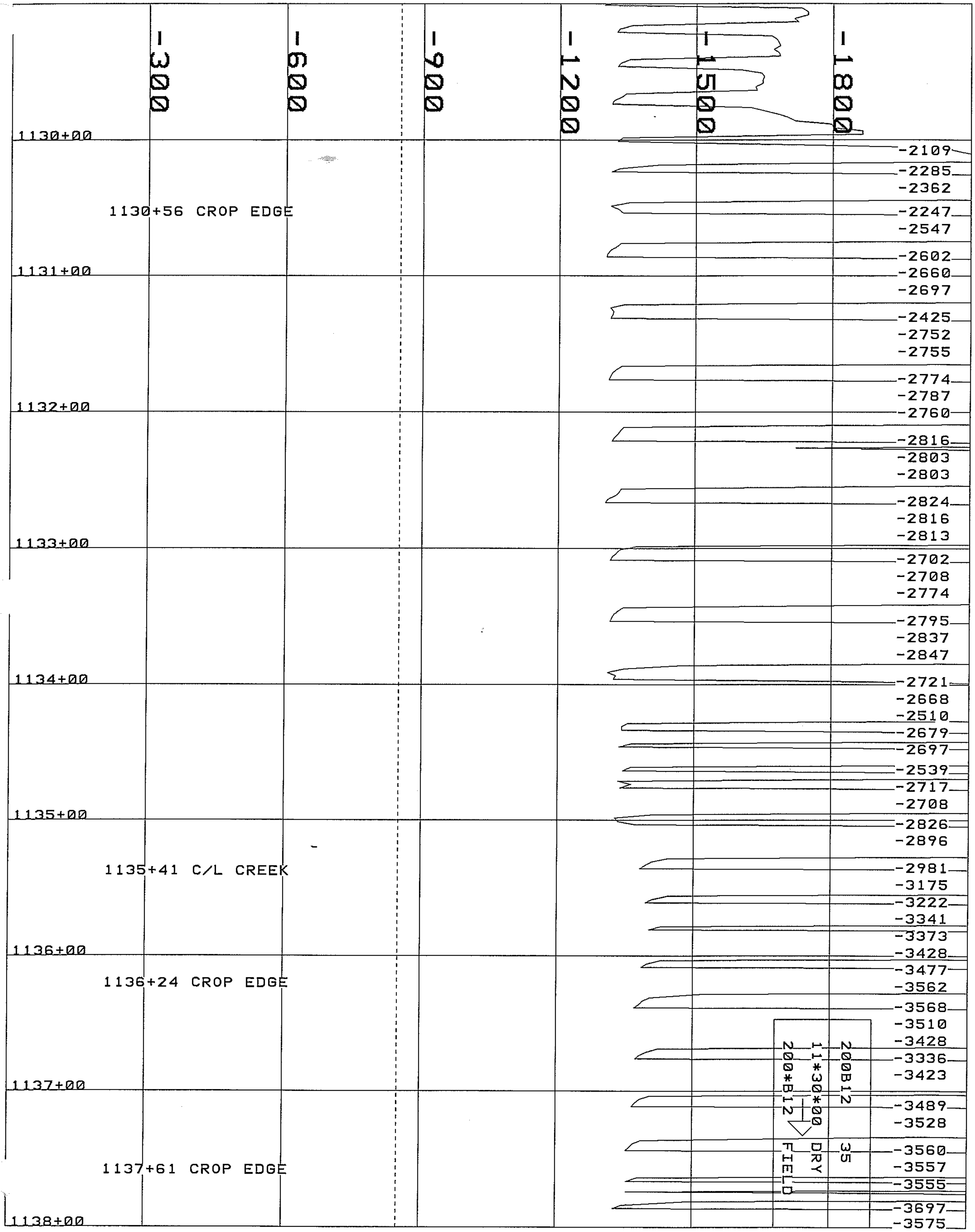
Pipe/Soil Potential (mv)




Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
1112+00
1113+00
1114+00
1114+04 CROP EDGE
1114+38 C/L DITCH
1114+78 CROP EDGE
1115+00
1116+00
1117+00
1118+00
1119+00
1120+00
Distance (feet)

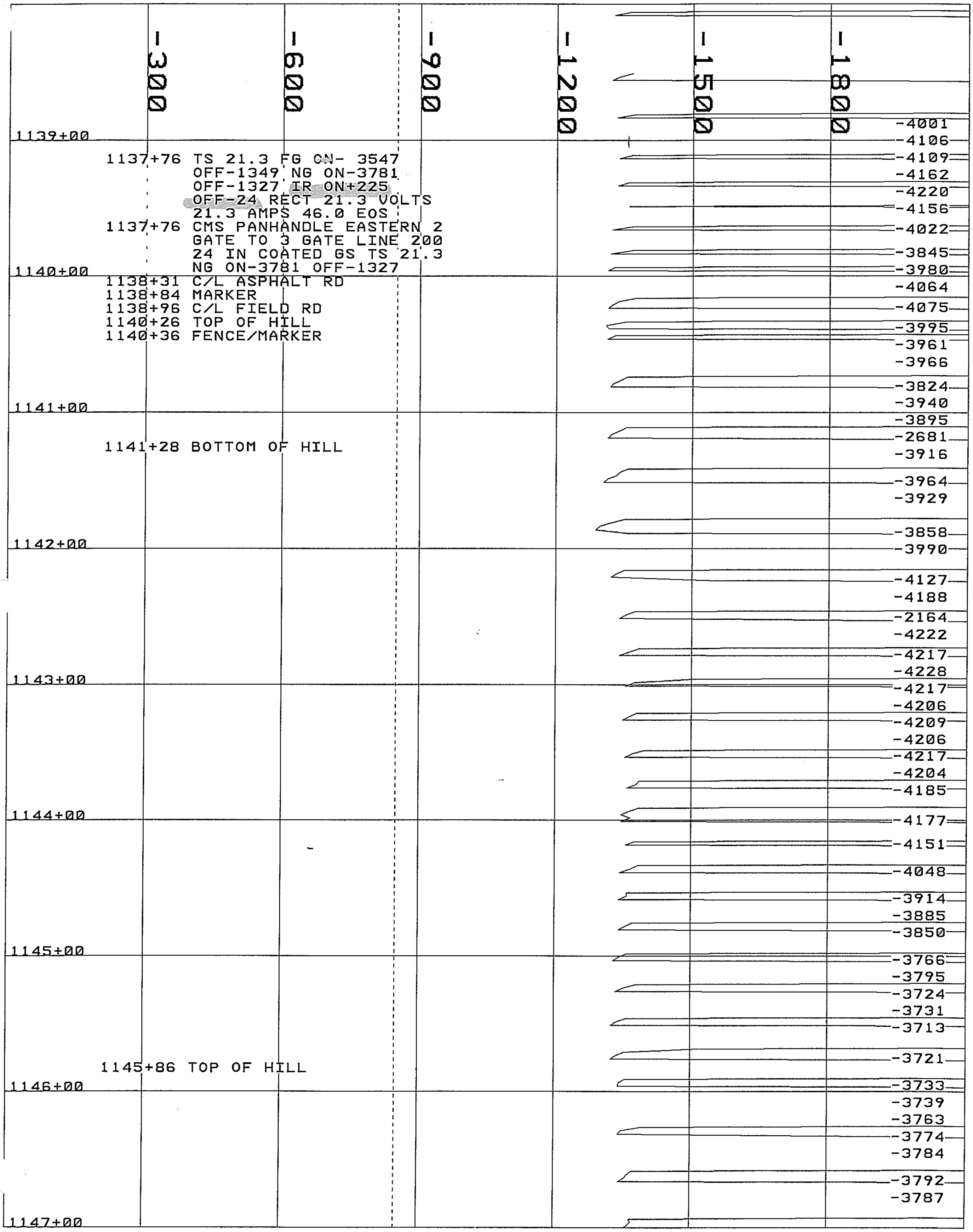

Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
1121+00
1122+00
1122+21 CROP EDGE
1122+66 FENCE/MARKER
1123+00
1124+00
1125+00
1126+00
1126+61 C/L CREEK BOTTOM OF HILL
1127+00
1128+00
1129+00
-2119
-2194
-2248
-2222
-2204
-2174
-2169
-2148
-2138
-2127
Distance (feet)

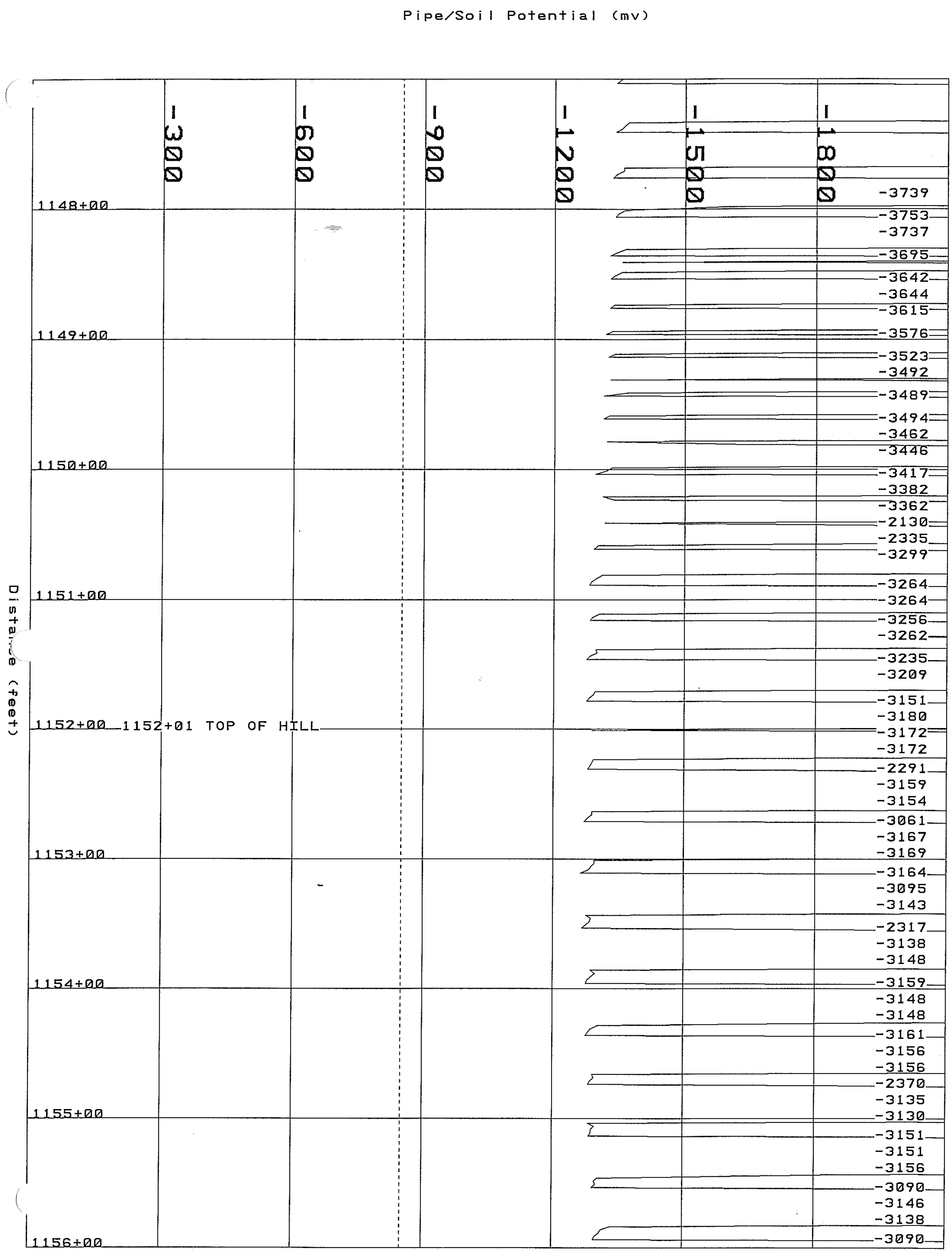
Pipe/Soil Potential (mv)

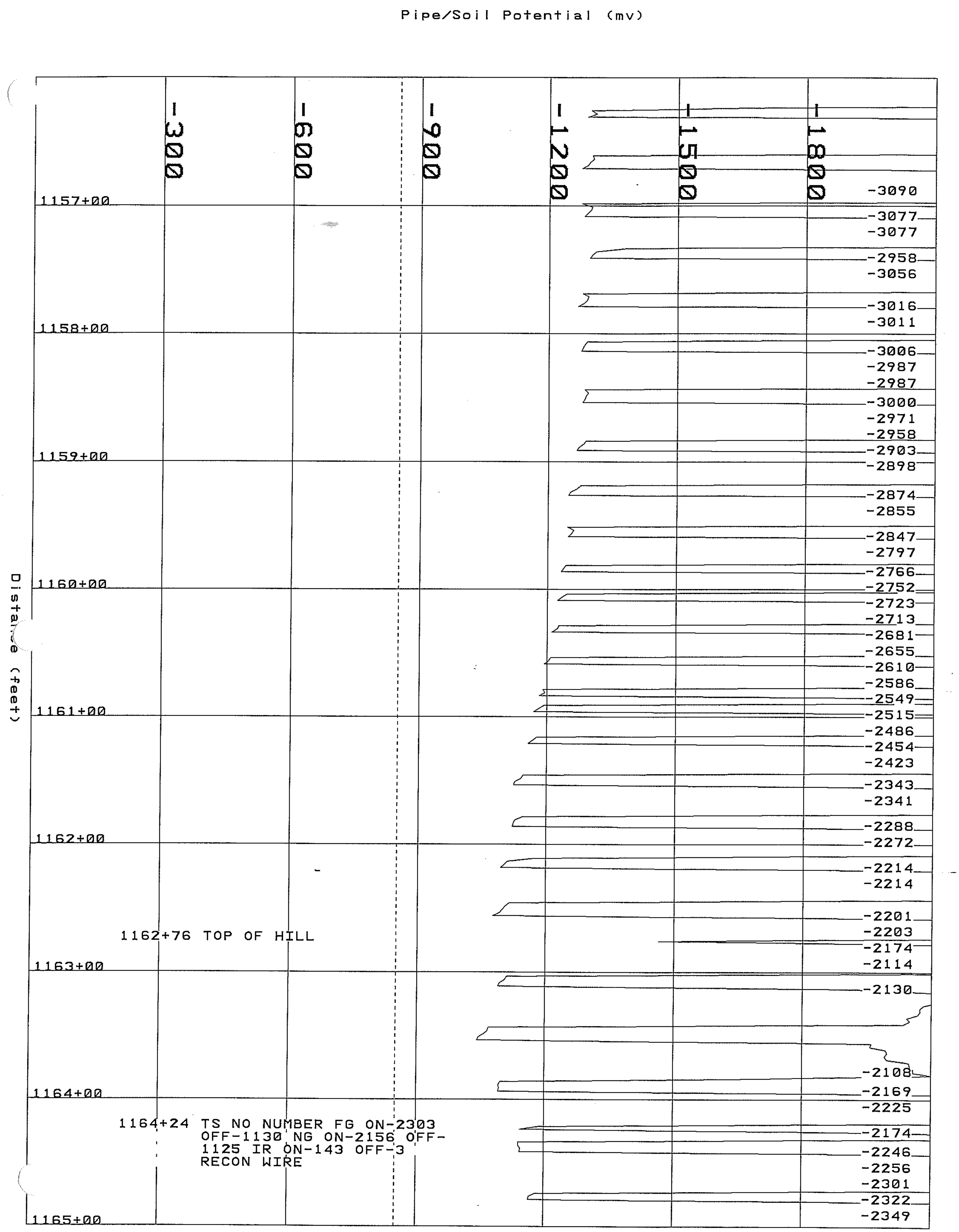


Distance (feet)

Pipe/Soil Potential (mv)

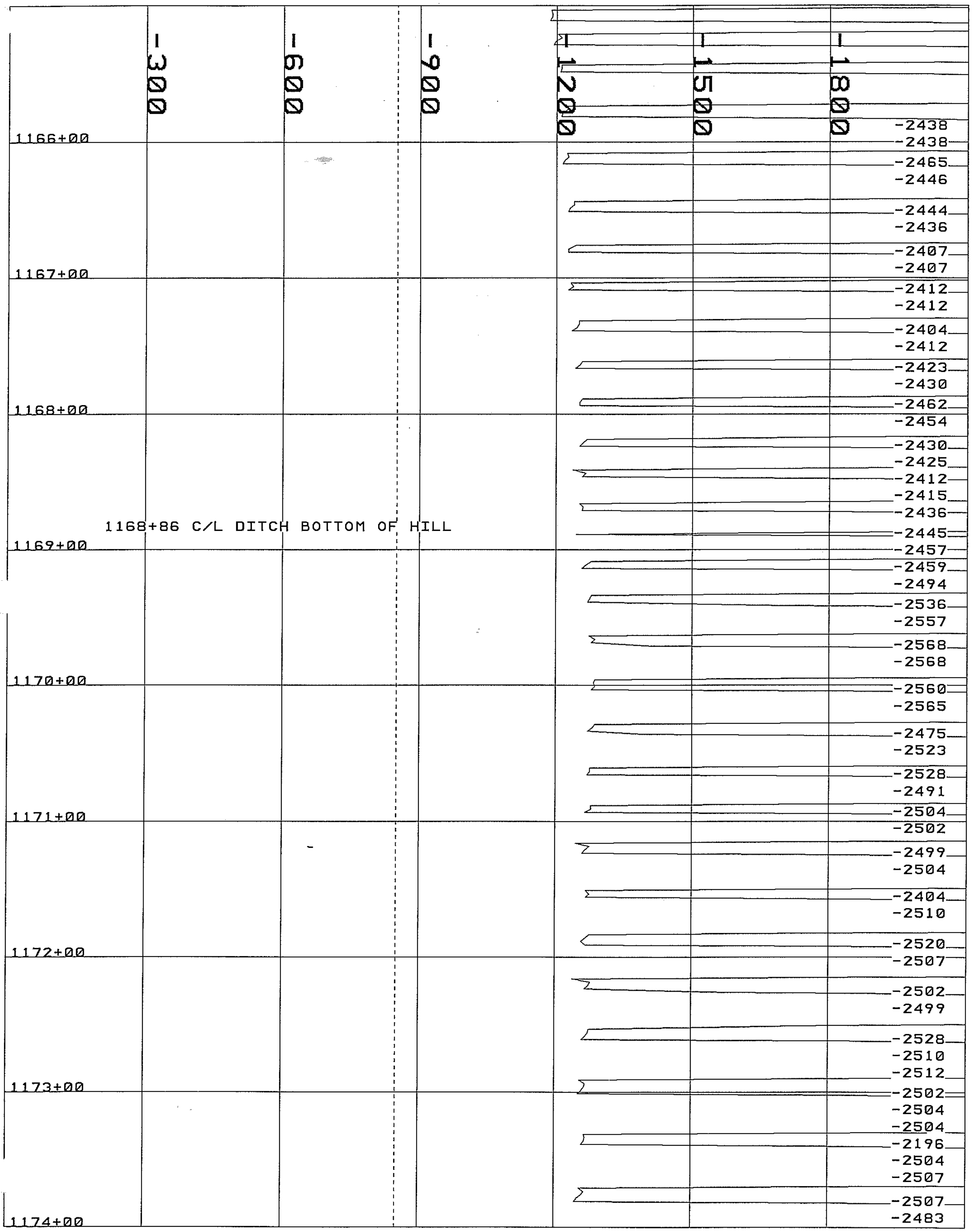



Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1148+00
1149+00
1150+00
1151+00
1152+00
1152+01 TOP OF HILL
1153+00
1154+00
1155+00
1156+00
-3739
-3753
-3737
-3695
-3642
-3644
-3615
-3576
-3523
-3492
-3489
-3494
-3462
-3446
-3417
-3382
-3362
-2130
-2335
-3299
-3264
-3264
-3256
-3262
-3235
-3209
-3151
-3180
-3172
-3172
-2291
-3159
-3154
-3061
-3167
-3169
-3164
-3095
-3143
-2317
-3138
-3148
-3159
-3148
-3148
-3161
-3156
-3156
-2370
-3135
-3130
-3151
-3151
-3156
-3090
-3146
-3138
-3090

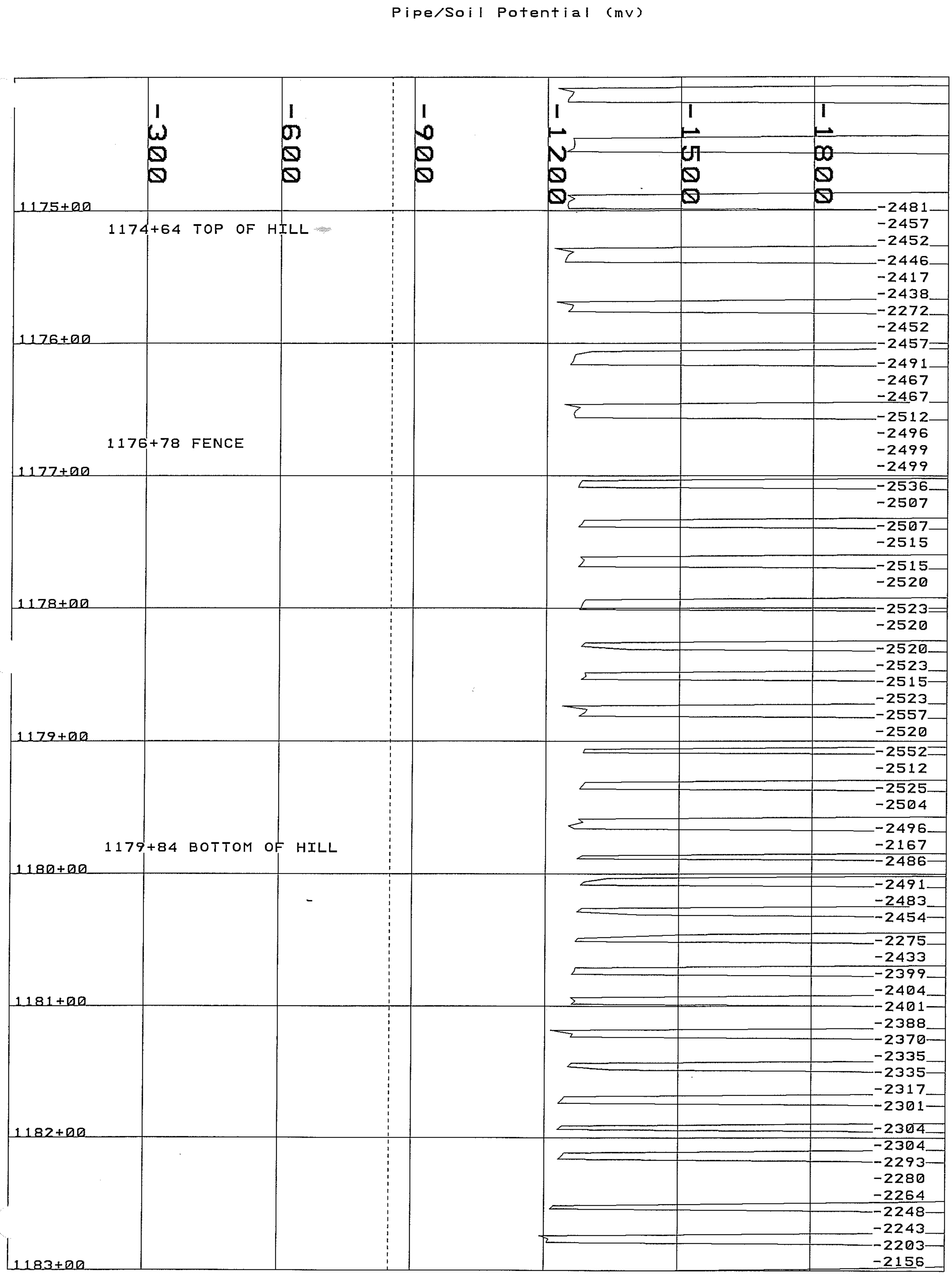


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1157+00
1158+00
1159+00
1160+00
1161+00
1162+00
1163+00
1164+00
1165+00
1162+76 TOP OF HILL
1164+24 TS NO NUMBER FG ON-2303 OFF-1130 NG ON-2156 OFF-1125 IR ON-143 OFF-3 RECON WIRE
-3090
-3077
-3077
-2958
-3056
-3016
-3011
-3006
-2987
-2987
-3000
-2971
-2958
-2903
-2898
-2874
-2855
-2847
-2797
-2766
-2752
-2723
-2713
-2681
-2655
-2610
-2586
-2549
-2515
-2486
-2454
-2423
-2343
-2341
-2288
-2272
-2214
-2214
-2201
-2203
-2174
-2114
-2130
-2108
-2169
-2225
-2174
-2246
-2256
-2301
-2322
-2349

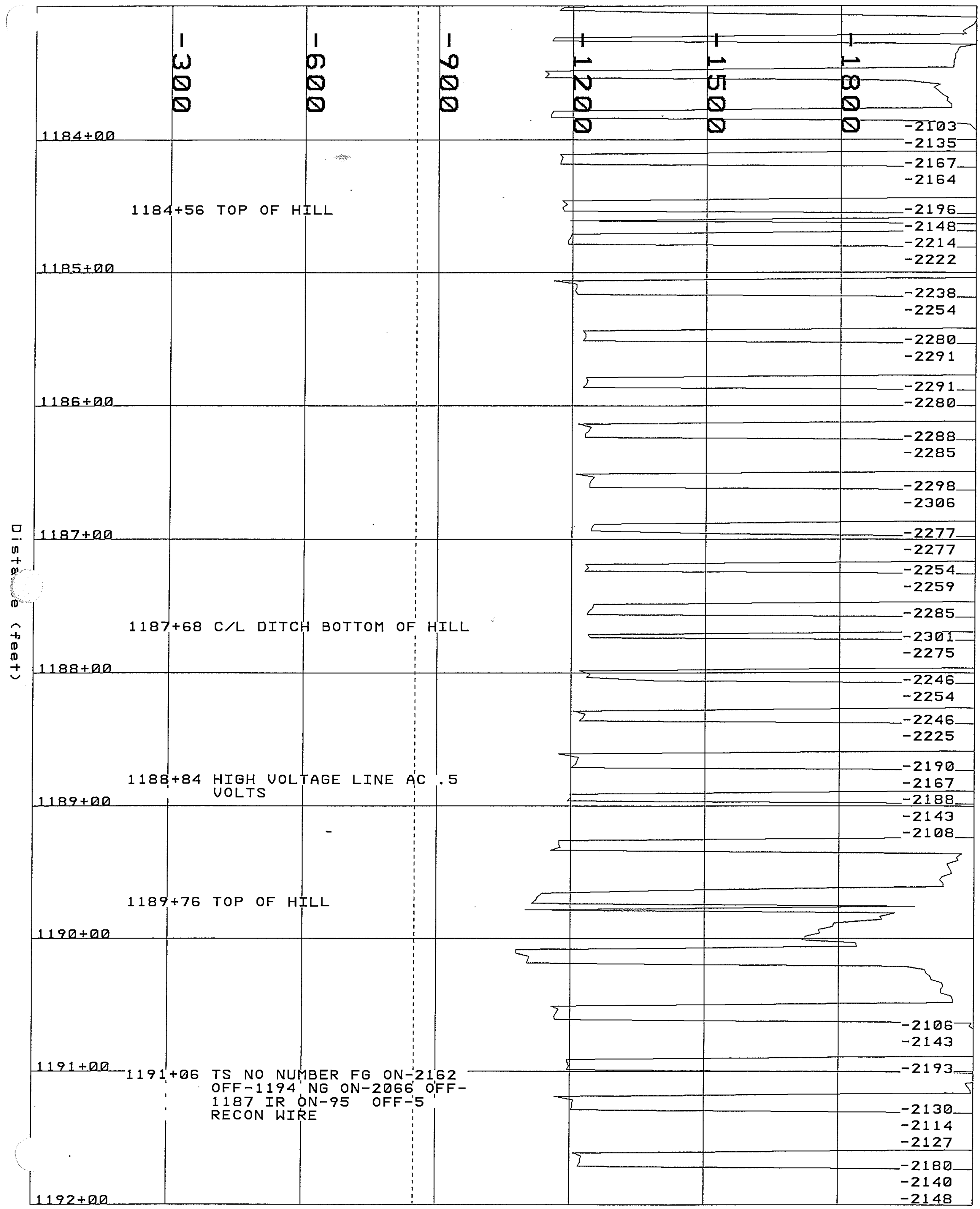
Pipe/Soil Potential (mv)



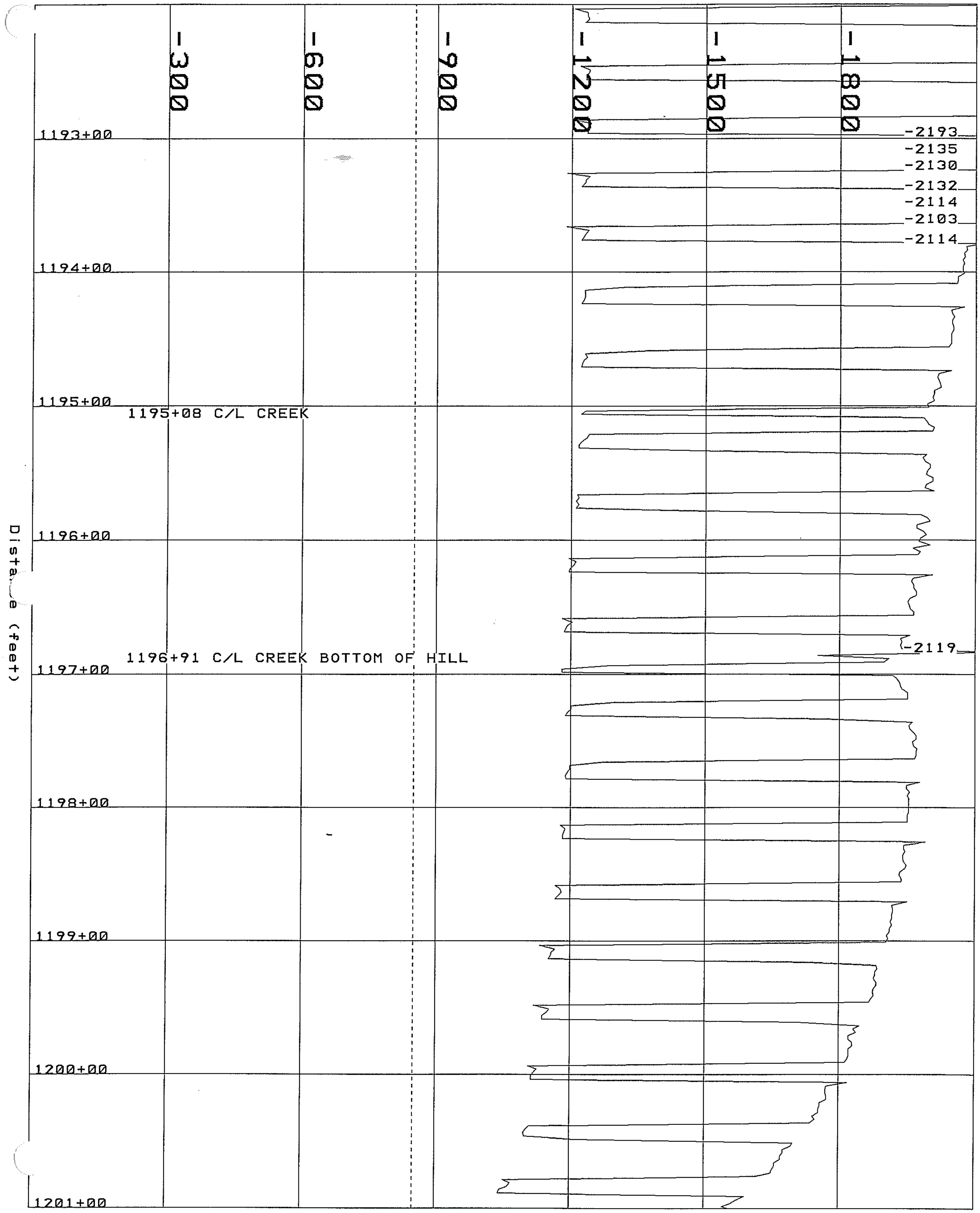
Distance (feet)


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1175+00
1174+64 TOP OF HILL
1176+00
1176+78 FENCE
1177+00
1178+00
1179+00
1179+84 BOTTOM OF HILL
1180+00
1181+00
1182+00
1183+00
-2481
-2457
-2452
-2446
-2417
-2438
-2272
-2452
-2457
-2491
-2467
-2467
-2512
-2496
-2499
-2499
-2536
-2507
-2507
-2515
-2515
-2520
-2523
-2520
-2520
-2523
-2515
-2523
-2557
-2520
-2552
-2512
-2525
-2504
-2496
-2167
-2486
-2491
-2483
-2454
-2275
-2433
-2399
-2404
-2401
-2388
-2370
-2335
-2335
-2317
-2301
-2304
-2304
-2293
-2280
-2264
-2248
-2243
-2203
-2156

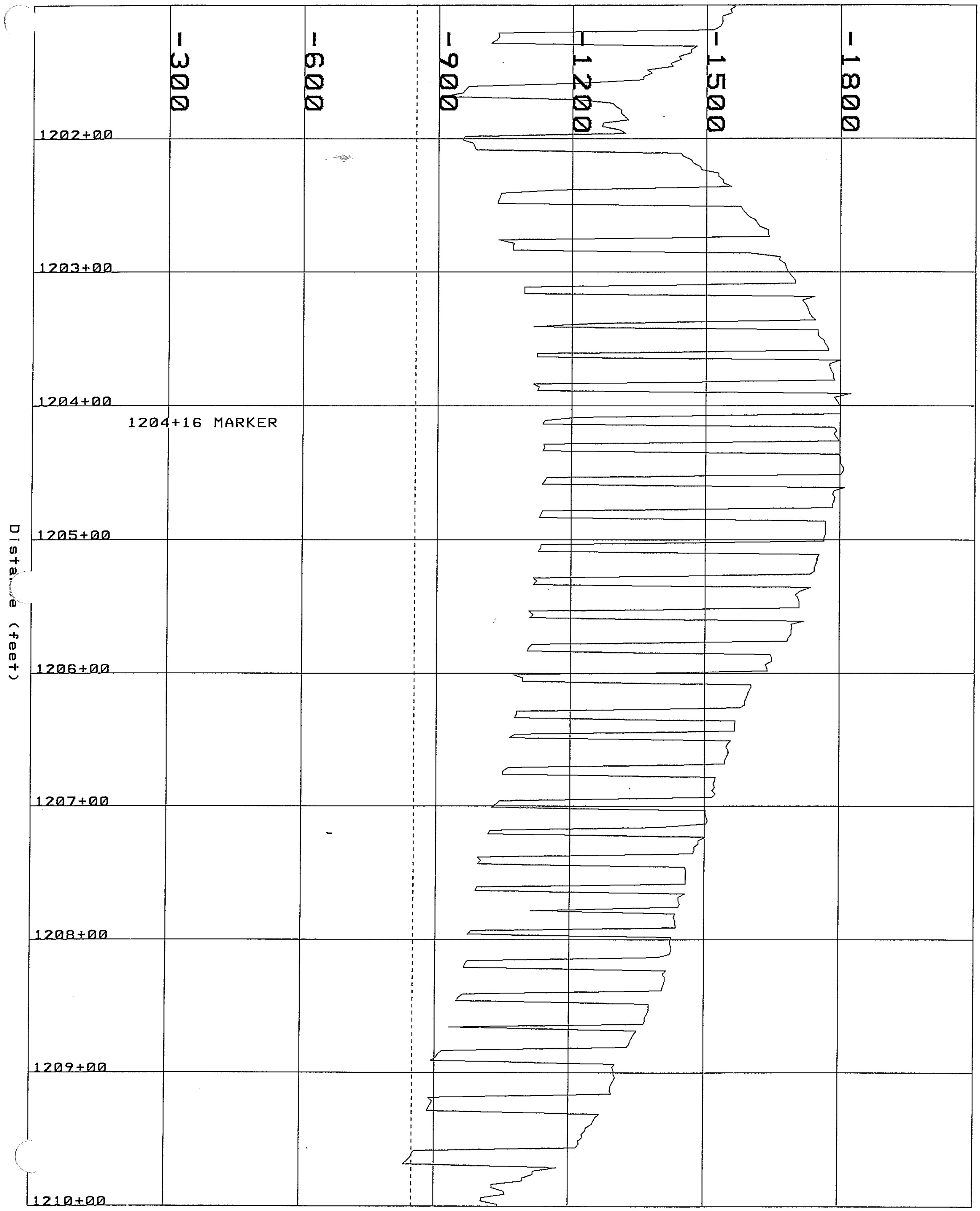
Pipe/Soil Potential (mv)

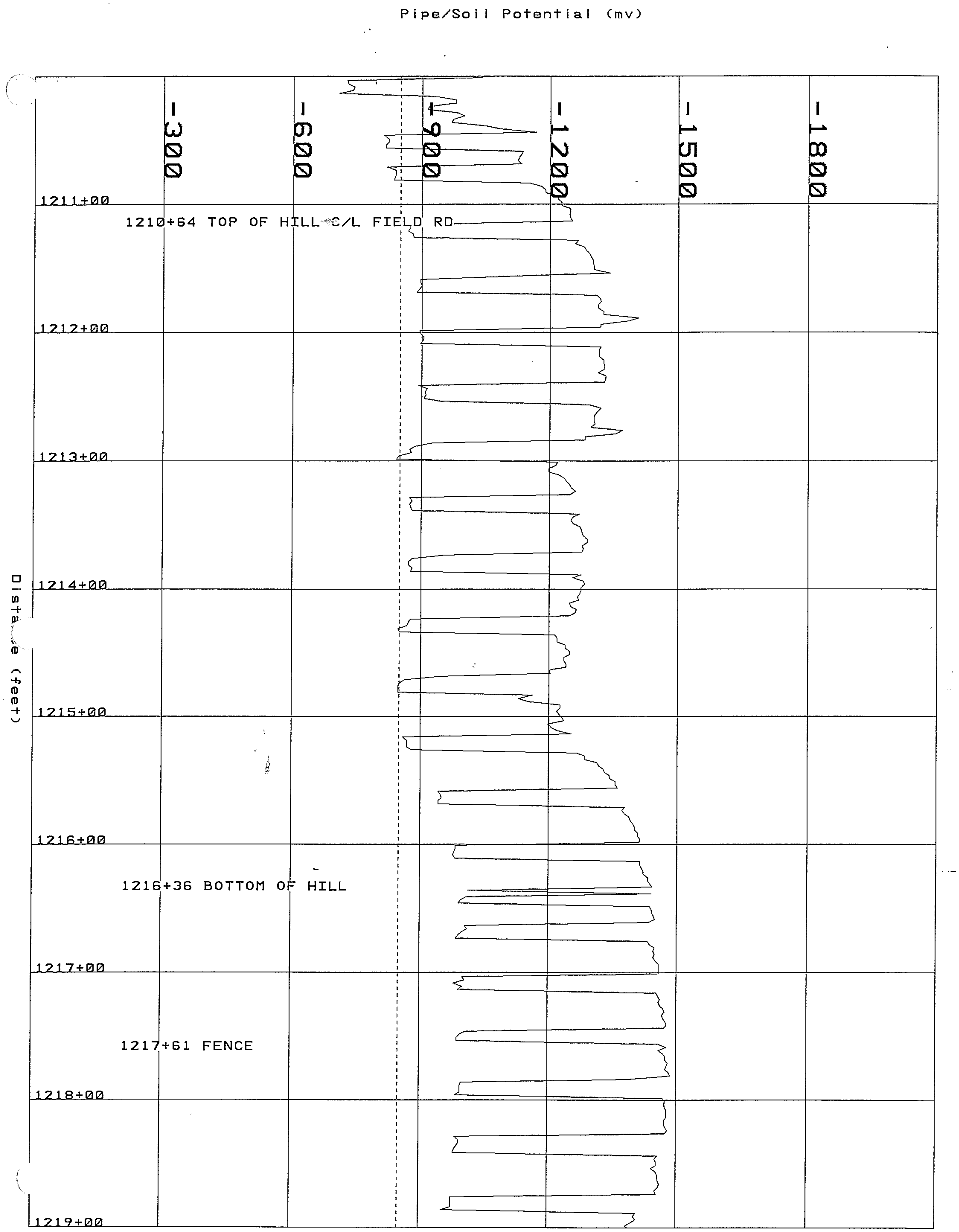


Pipe/Soil Potential (mv)



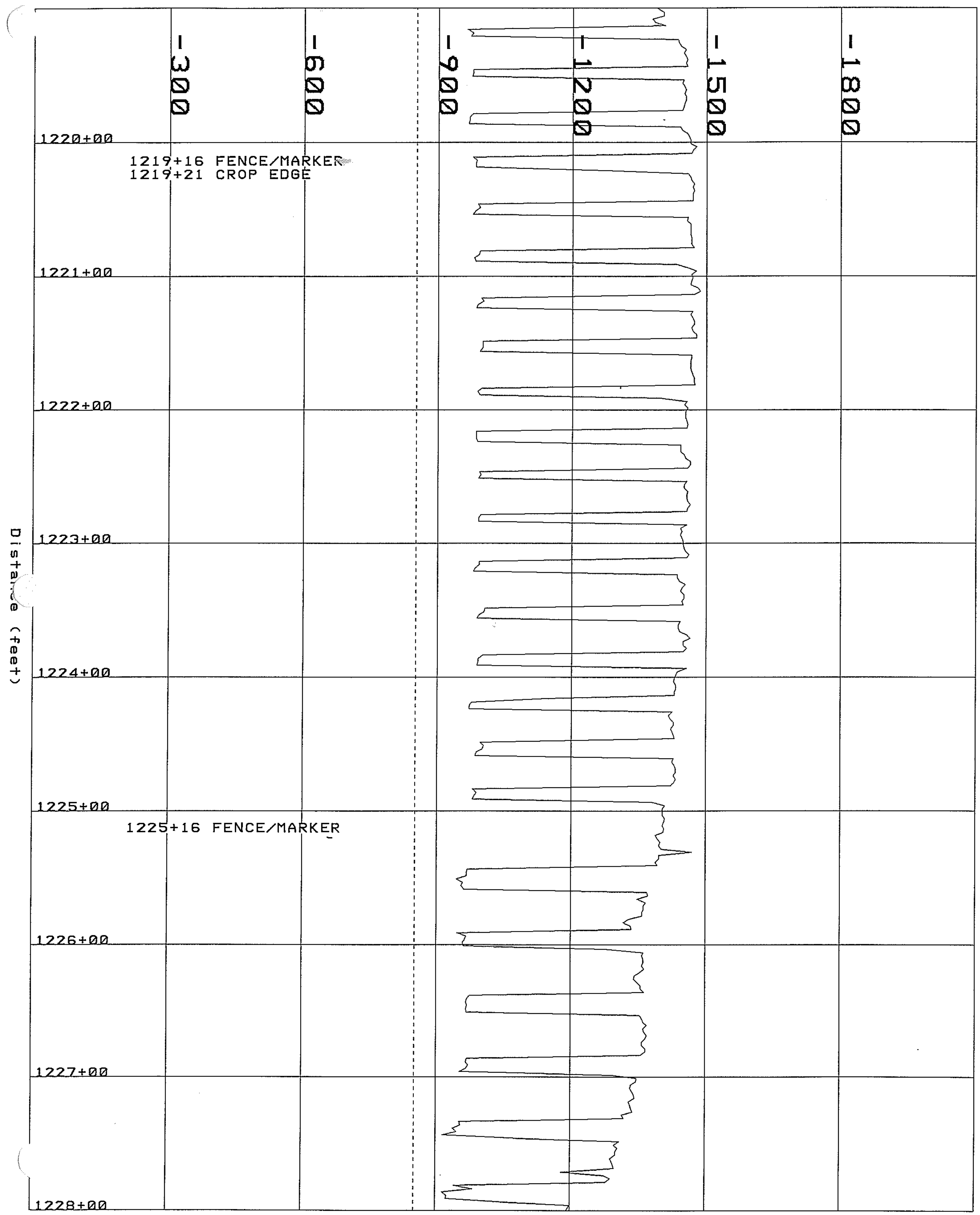
Pipe/Soil Potential (mv)

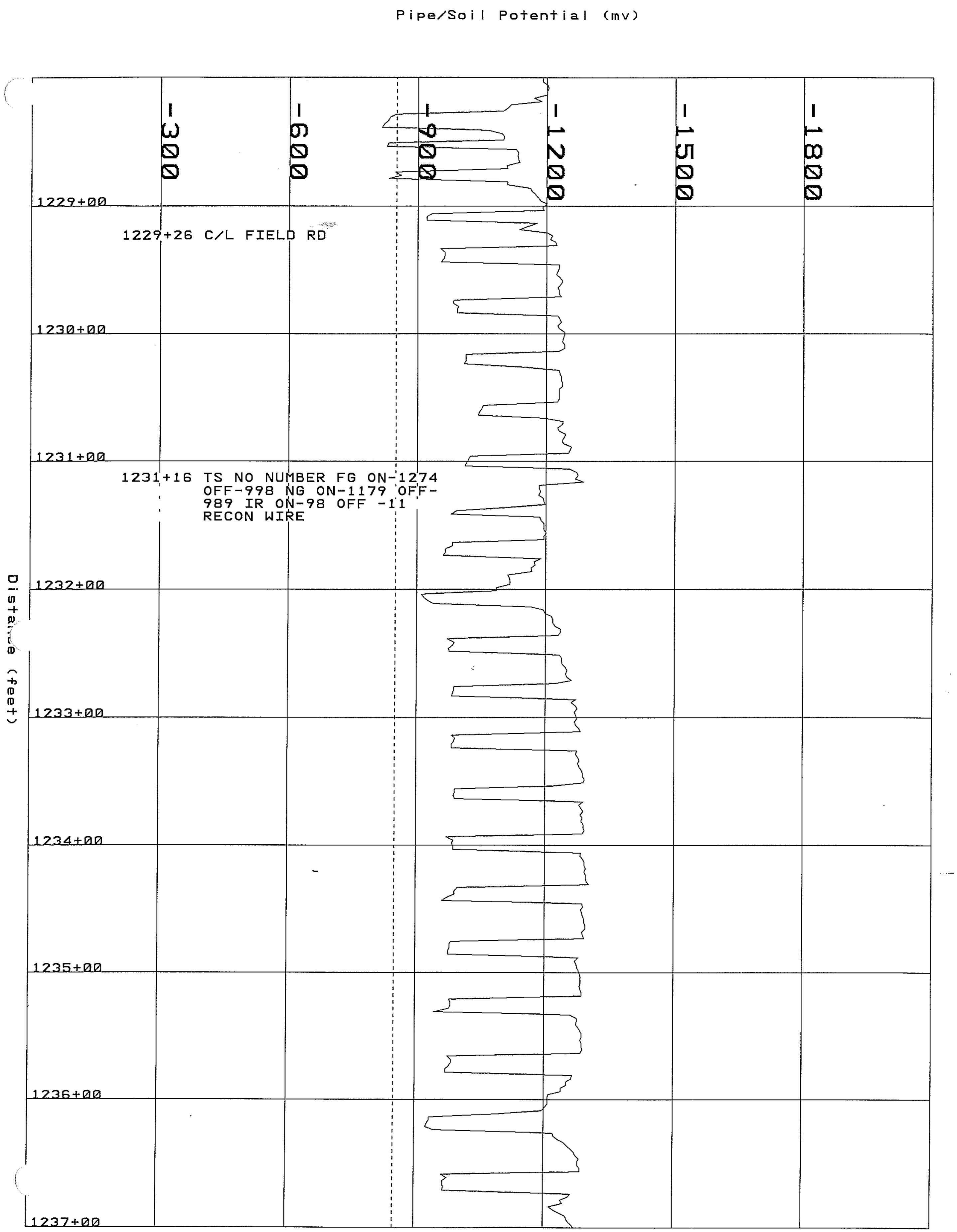




Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
1211+00
1210+64 TOP OF HILL C/L FIELD RD
1212+00
1213+00
1214+00
1215+00
1216+00
1216+36 BOTTOM OF HILL
1217+00
1217+61 FENCE
1218+00
1219+00
Distance (feet)

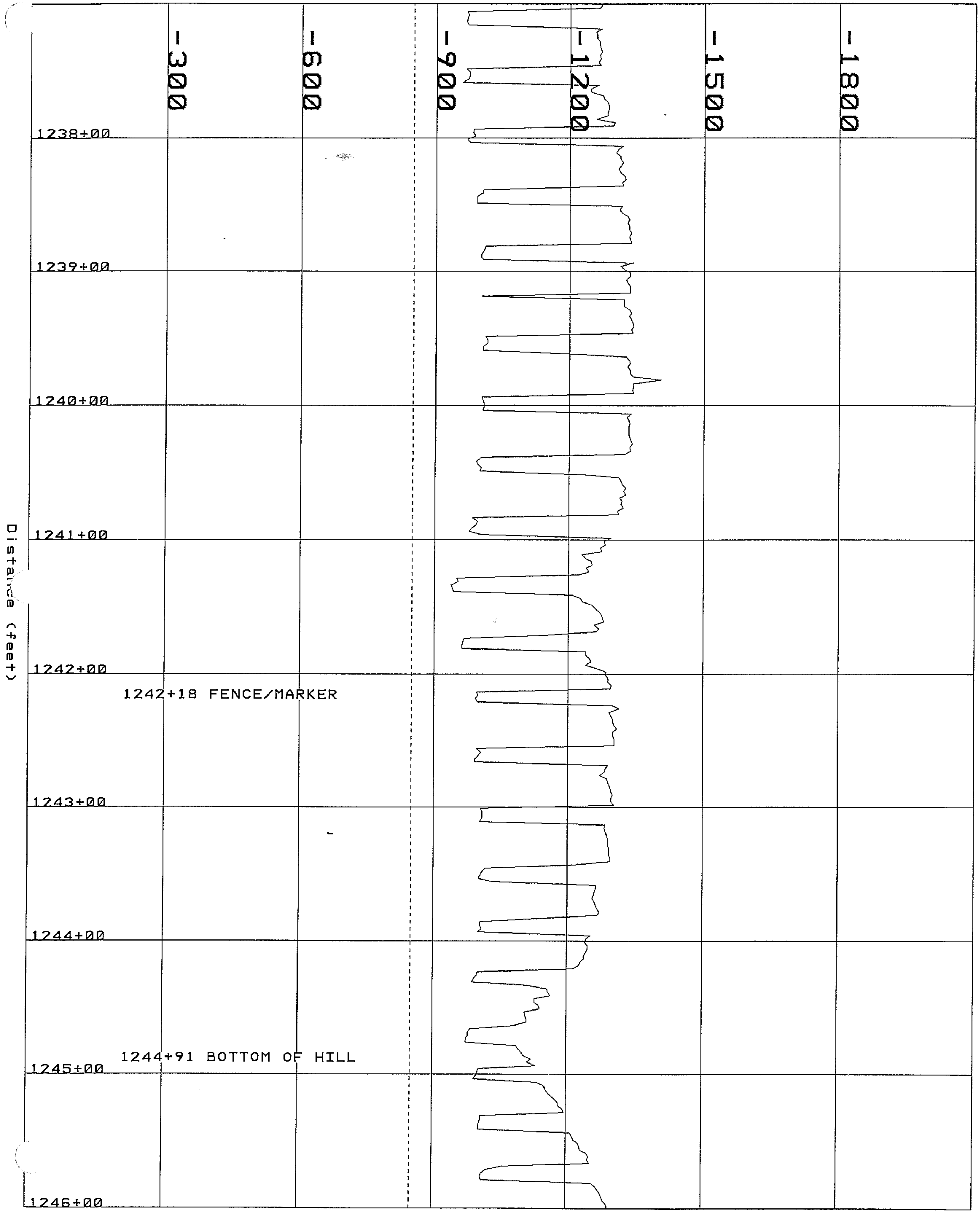
Pipe/Soil Potential (mv)



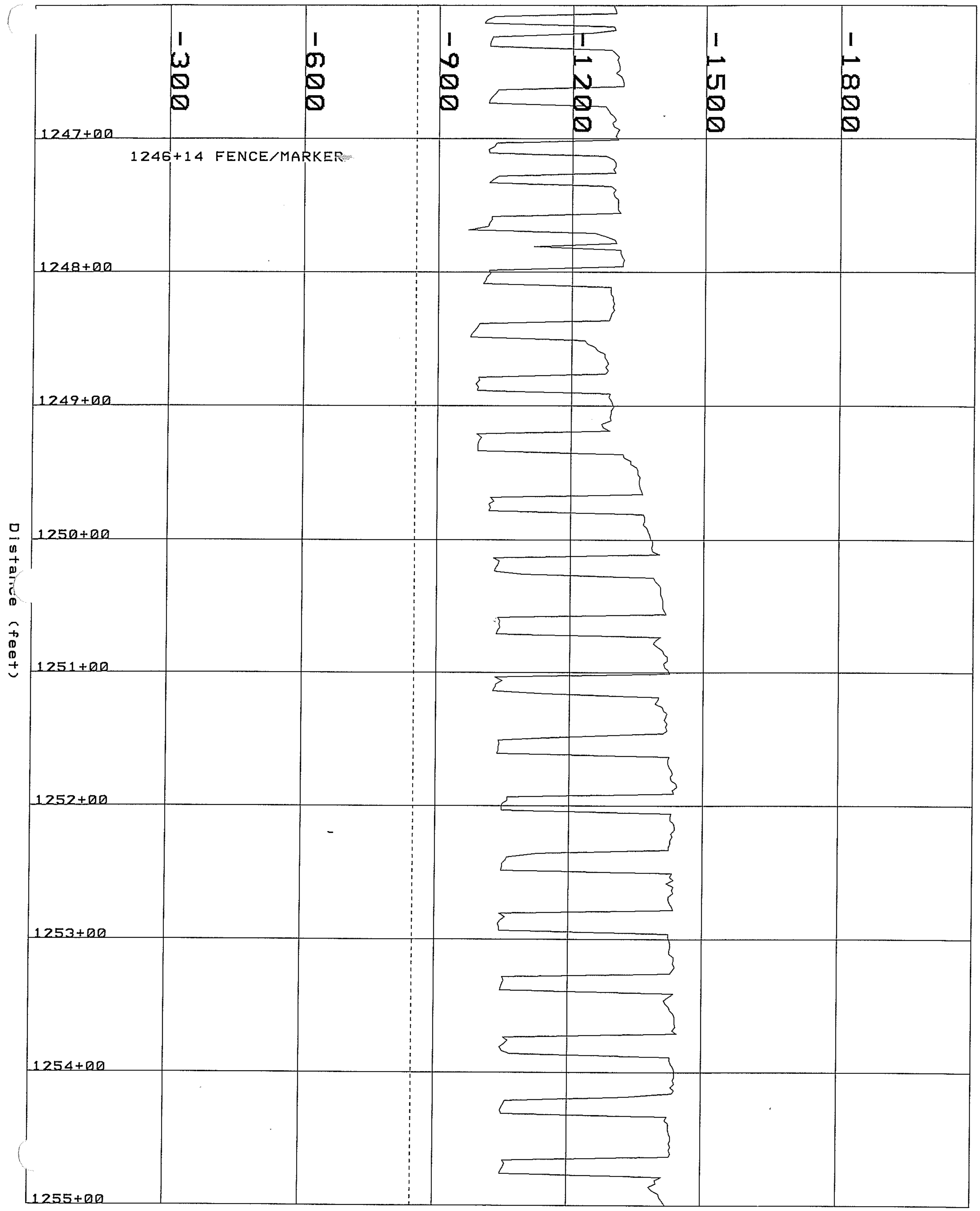


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1229+00
1229+26 C/L FIELD RD
1230+00
1231+00
1231+16 TS NO NUMBER FG ON-1274 OFF-998 NG ON-1179 OFF-989 IR ON-98 OFF -11 RECON WIRE
1232+00
1233+00
1234+00
1235+00
1236+00
1237+00

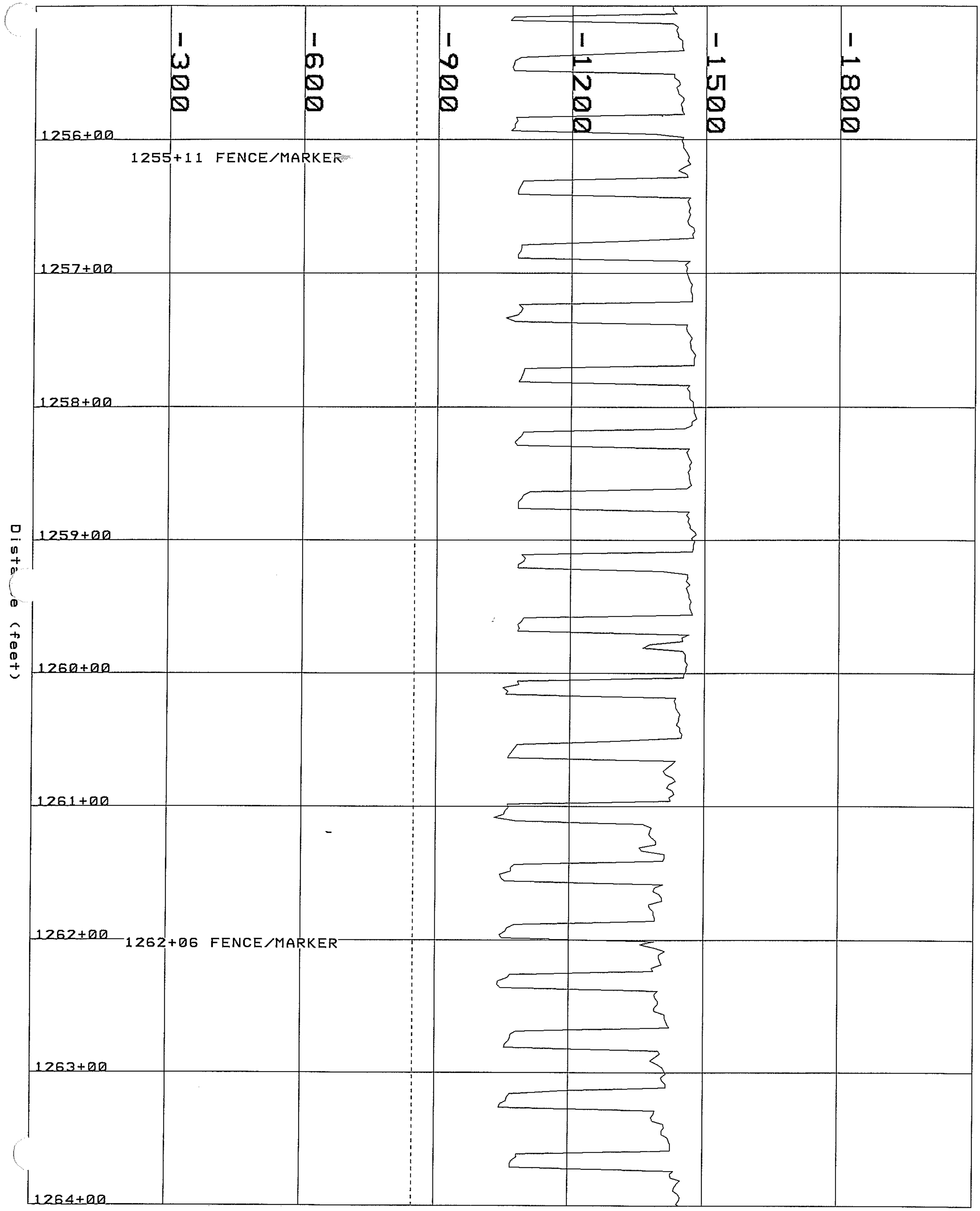
Pipe/Soil Potential (mv)

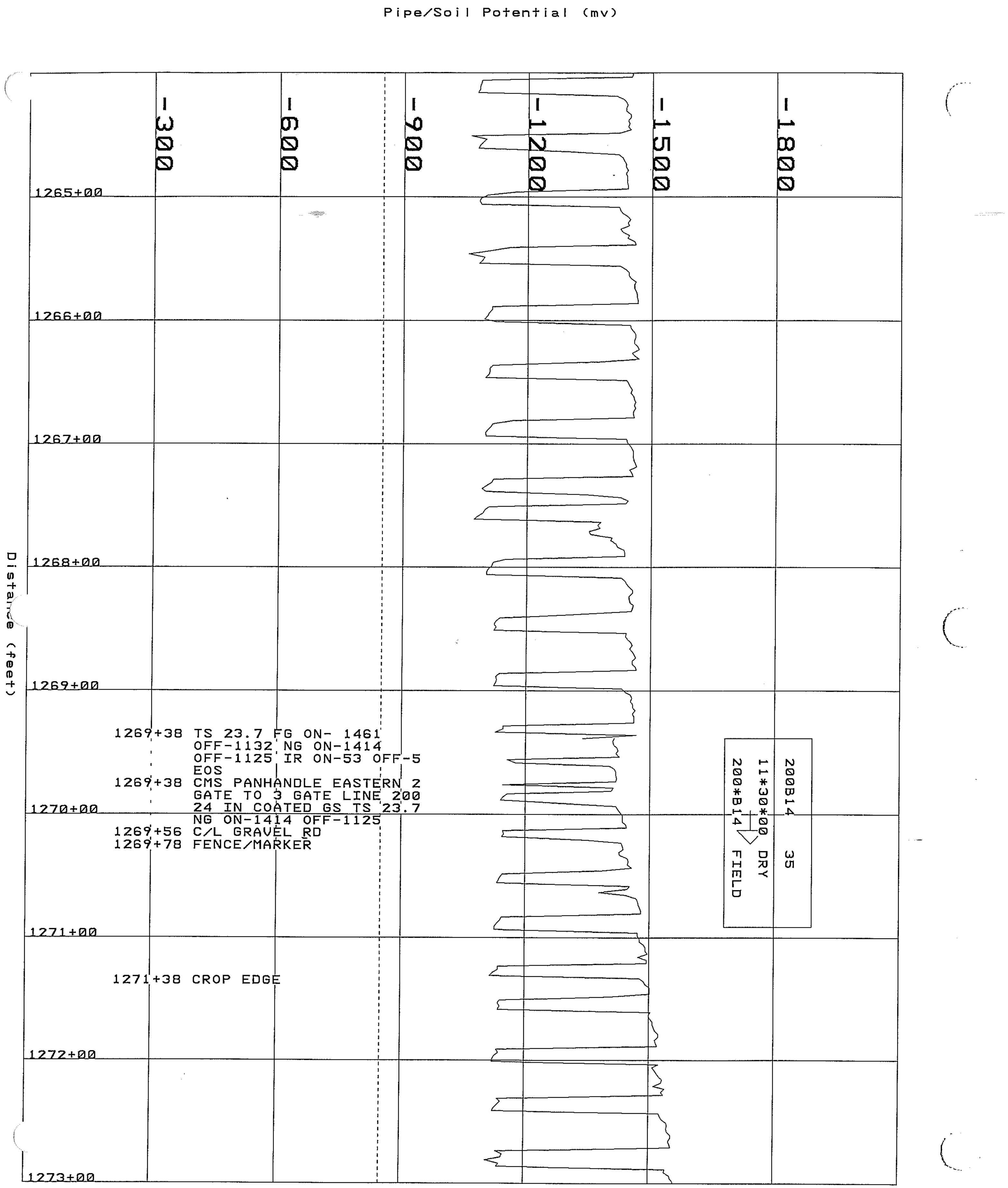


Pipe/Soil Potential (mv)

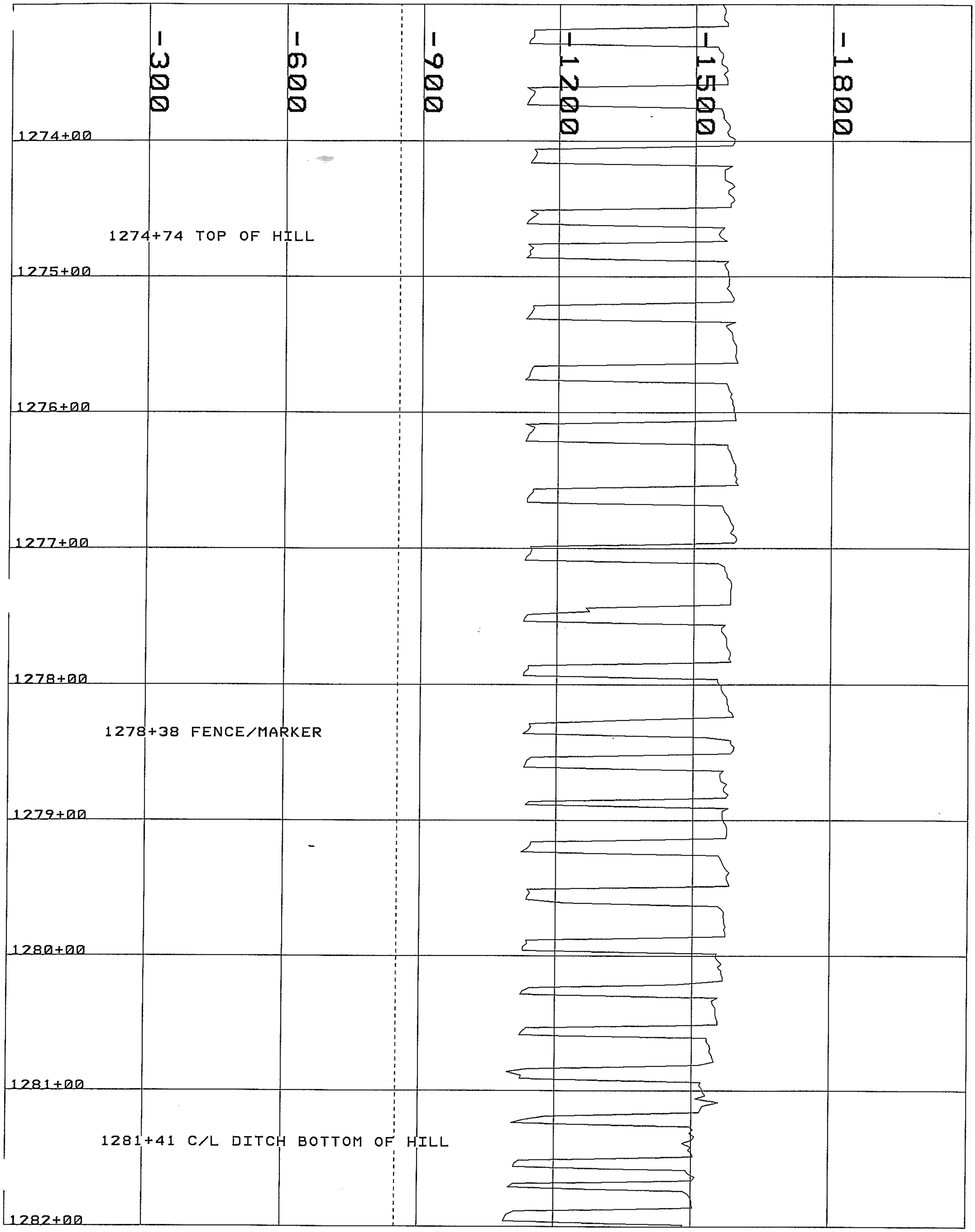


Pipe/Soil Potential (mv)

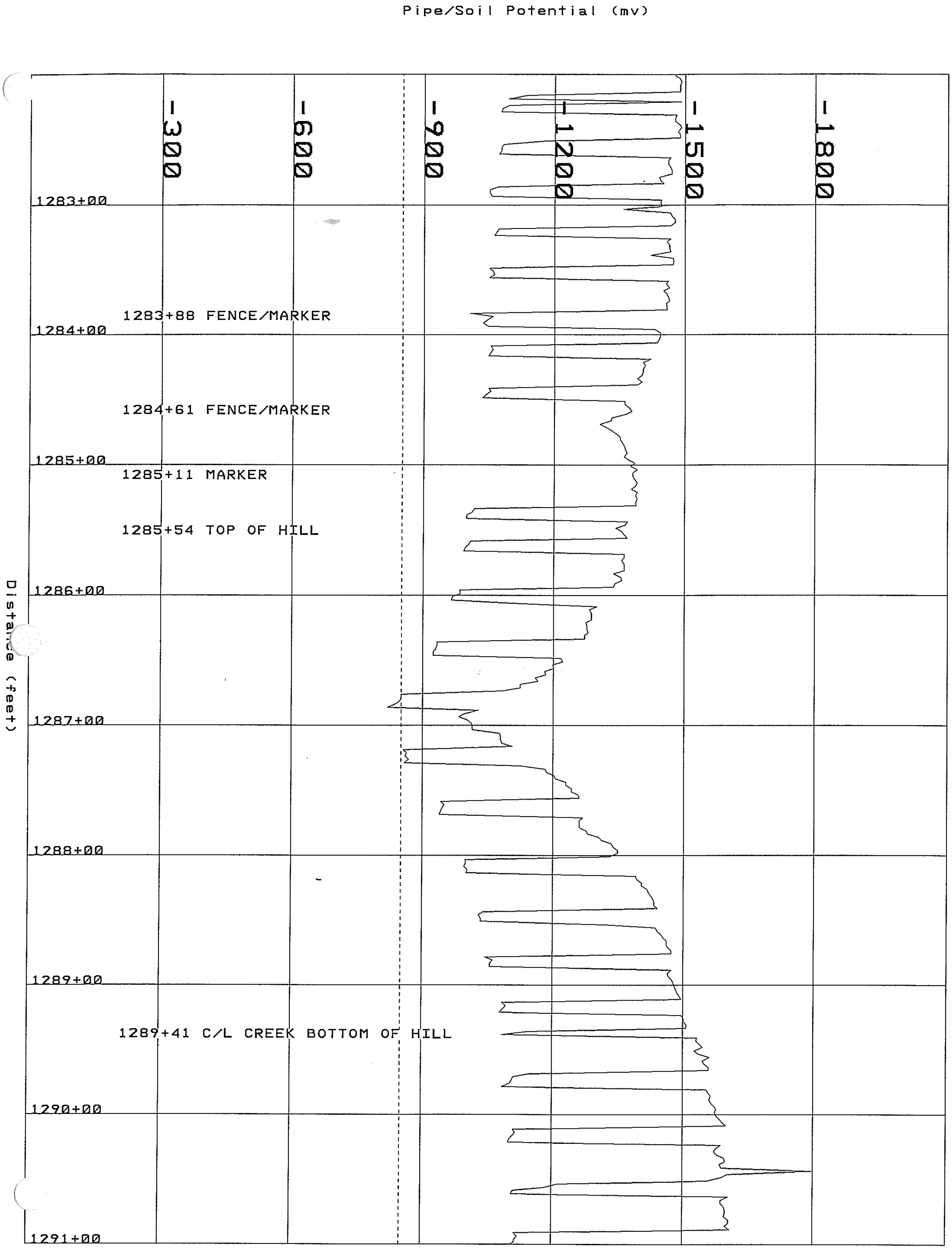


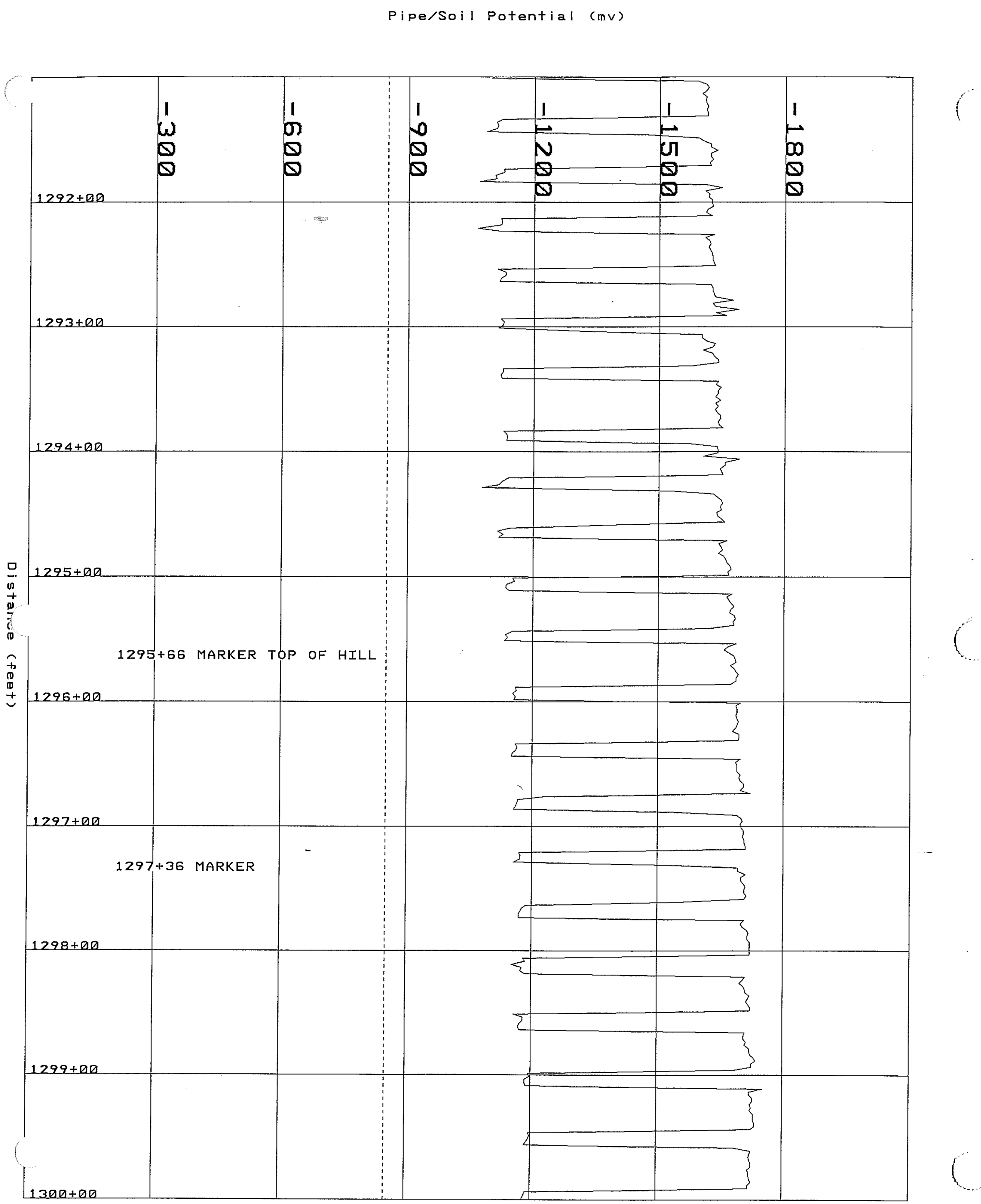

Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1265+00
1266+00
1267+00
1268+00
1269+00
1270+00
1271+00
1272+00
1273+00
1269+38 TS 23.7 FG ON- 1461
OFF-1132 NG ON-1414
OFF-1125 IR ON-53 OFF-5
EOS
1269+38 CMS PANHANDLE EASTERN 2
GATE TO 3 GATE LINE 200
24 IN COATED GS TS 23.7
NG ON-1414 OFF-1125
1269+56 C/L GRAVEL RD
1269+78 FENCE/MARKER
1271+38 CROP EDGE
200B14 35
11*30*00 DRY
200*B14 FIELD

Pipe/Soil Potential (mv)



Distance (feet)


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1283+00
1283+88 FENCE/MARKER
1284+00
1284+61 FENCE/MARKER
1285+00
1285+11 MARKER
1285+54 TOP OF HILL
1286+00
1287+00
1288+00
1289+00
1289+41 C/L CREEK BOTTOM OF HILL
1290+00
1291+00


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
1292+00
1293+00
1294+00
1295+00
1295+66 MARKER TOP OF HILL
1296+00
1297+00
1297+36 MARKER
1298+00
1299+00
1300+00

Pipe/Soil Potential (mv)