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Ex. II - 1

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VERTILOG® – A DOWN-HOLE CASING INSPECTION SERVICE

BY

JOHN N. HAIRE AND JEARALD D. HEFLIN, MEMBERS SPE-AIME, DRESSER ATLAS

ABSTRACT

In California the shortages and resulting economics of new oil has intensified the search for new sources. With casing and drilling costs increasing, this search has resulted in a renewed interest and re-evaluation of many existing wells.

A knowledge of the condition of the existing casing is necessary for repairs, workovers, and possible developement of additional zones.

The Vertilog is a casing inspection service which is now available to the oil and gas industry to determine the condition of the casing in existing wells. It is a quantitative measurement of corrosive damage, indicating if the metal loss is internal or external, and if it is isolated or circumferential. Holes in the casing can be identified as well as parted casing. This survey in conjunction with other measurements, can be used to detect, monitor, and establish preventive techniques for corrosive problems.

This paper is intended to familiarize the industry with tool specifications, theory of operations, calibrations, applications, interpretation principles, and field examples.

INTRODUCTION

The Vertilog is a downhole casing inspection service. The recordings produced allow identification of damaged intervals and severity of corrosion. Measurements taken determine if corrosion or damage is internal or external and if it is isolated or circumferential.

Due to instrument design, casing inspection covers the full circumference and minor elongation does not effect the reliability of the measurements. Anomalies as small as 1/8" in diameter with as little as 20% penetration of the nominal bodywall of the casing can be detected.

All casing sizes, weights, and grades from 4-1/2" O.D. through 8-5/8" O.D., except 6-5/8" O.D., can be inspected at the present time.

The tools are temperature rated at 250°F and pressure rated at 10,000 PSI.

The logging speed is 125 feet per minute and no special borehole fluids are required for the survey. It is recommended that the casing be scraped just prior to the survey for the most definitive measurements.

PRESENTATION

The data is presented in a standard log format, however, the usual depth scale is 10" per 100 feet of borehole for improved definition. The measurements are presented on a four track log grid as illustrated in Figure 1.

Track one and two are designated as Flux Leakage-1 (FL-1) and Flux Leakage-2 (FL-2) and correspond to the two rings of shoes on the Vertilog instrument. Recorder deflections in these tracks indicate the severity of corrosion that has taken place and also the location of the collars.

The third track is designated the Disciminator Track with recorder deflections allowing interpretation of whether the damage is internal or external.

The fourth track is referred to as the Average Track. The ratio of the height of the signal recorded by a casing collar (360°) to one within a joint determines if the damage is isolated or circumferential.

Figure 2 is a comparison of an Electrolog recorded on a well in California in 1945 and casing set through the interval and the well completed below. On the right is a Vertilog recorded in 1976 showing the condition of the casing. It shows a correlative of severe damage, with holes in the casing, in the string which is next to the permeable, fluid bearing intervals. It is the condition of the casing, in intervals such as these, which has to be known to enable the engineer to properly evaluate future potentials and cost estimates of the well.

Figure 3 is a section of the log from this well illustrating the magnitude of the outside circumferencial damage and indicating areas where this has resulted in holes in the casing.

This survey has proven to be the most accurate method of locating perforated intervals, determining effectiveness, as well as indicating shot density. This is illustrated in Figure 4.

Well completion equipment is detected with the Vertilog as illustrated in Figure 5 showing scratchers and centralizers.

THEORY OF OPERATION

The Vertilog® instrument is designed for maximum resolution for each size of casing. Because of this a different tool is required for each size of casing. Figure 6 gives tool specifications for the available sizes. The instrument designed to survey 8-5/8" O.D. casing is shown in Figure 7.

A basic block diagram of the Vertilog system incorporating the shoes, electronics, wireline, and recorder is shown in Figure 8.

The downhole instrument consists of six or twelve shoes (depending on size casing being surveyed), an electromagnet and two electronic packages. Figure 9 illustrates the shoe section of the tool. Each shoe has four transducers, two connected to each electronic package. The Flux Leakage (FL) electronic package processes the signal relating to the severity of the corrosion. The Eddy Current (EC) electonic package discriminates between internal and external corrosion.

The two electronic packages relate directly to the two principles used in the Vertilog system.

The magnetic flux leakage detection theory is used in the FL package and eddy current sensing is used in the EC package.

Since the recorded log, the magnetic principles, and electronic packages are all inter-related they will be discussed together.

Flux Leakage

The Flux Leakage electronic package will be discussed first. The signals processed through this package are recorded in tracks one and two on the log.

If a DC current is sent through a coil of wire, a magnetic field will be generated along the axis of the coil. The magnitude of the magnetic field will be determined by the amount of current sent through the coil and the number of turns in the coil of wire.

This magnetic field consistes of lines of force called magnetic flux lines. These magnetic flux lines have two basic properties that the Vertilog system uses.

1. Magnetic flux lines will travel through casing much easier than they will through air or fluids.
2. One magnetic flux line will not cross another flux line.

The Vertilog instrument has a coil of wire in its center. A regulated DC current is sent through the coil of wire. The magnitude of the current is made great enough to saturate the bodywall of the casing with magnetic lines of flux. As long as the bodywall of the casing is consistent then most of the magnetic flux lines will travel through the bodywall of the casing. This is illustrated in Figure 10. When corrosive pits appear, then flux leakage will occur. The amount of flux leakage that occurs will be proportional to the percentage of metal loss in the bodywall of the casing. When a coil of wire is passed through an area of flux leakage a small voltage will be generated.

The magnitude of the voltage will be determined by the design of the coil, the speed of the coil as it passes through the area of flux leakage, and the amount of flux leakage that the coil passes through.

Each shoe on the Vertilog tool has two coils of wire, called transducers, for flux leakage detection. The size of the coils are constant. The logging speed is constant at 125'/min. These conditions make the recorded signal of the flux leakage proportional to the percentage of metal loss in the bodywall of the casing. A visualization of the magnetic flux lines flowing around a pit in the casing bodywall is illustrated in Figure 11a. The resultant signal as the Vertilog® shoes pass the anomaly is illustrated in Figure 11b, 11c, and 11d.

The FL electronic package is divided into two sections and corresponds to the two rings of shoes on the instrument. The top ring of shoes is recorded in the FL-1 track and the bottom ring of shoes is recorded in the FL-2 track.

Since circumferential corrosion will produce a higher signal than an isolated pit of the same casing bodywall penetration, a method to distinguish between the two is necessary.

All the transducers in the top ring of shoes are connected to the circuit that produces the Average signal. The averaging circuit takes a portion of the signal that is produced by each transducer and adds them. A casing collar will produce a signal equal to 360 degrees in circumference. If we take the height of a signal produced by a casing collar on the average track and divide this height by the number of transducers in the top ring of shoes, then it can be determined what percentage of the signal each transducer contributed. Experimentation has shown that a signal recorded in the Average track that is equal to or greater than the percentage produced by 2½ transducers indicates an anomaly that is circumferential in nature.

The Average Track will also confirm that the Vertilog instrument is functioning properly. Anytime a signal is recorded in Flux leakage track one there should be a corresponding signal in the Average track.

Eddy Current

The amount of Flux leakage detected has been found to be related to the location of the leakage with respect to the transducers. Relative to the Vertilog instrument this means that internal corrosion will produce a greater signal on the log than external corrosion of the same casing bodywall penetration. The causes of internal and external corrosion are different so the interpretation of internal and external corrosion of FL-1 and FL-2 on the log will be different. The Discriminator circuit differentiates between the two--using an eddy current sensing technique.

By varying the amplitude and polarity of a current flowing through a coil of wire, a corresponding variance in the amplitude and polarity of the magnetic field produced by the coil will occur. If an electrical conductor is placed in this varying magnetic field, small varying eddy currents will be in the electrical conductor due to the relative movement of the magnetic field with respect to the electrical conductor. These eddy currents will produce small magnetic fields of their own. The small magnetic fields will have a polarity opposite that of the original field and will resist the original field.

This magnetic "resistance" is reflected back to the coil and causes a small change in amplitude of the current passing through it. The amplitude of the current passing through this eddy current coil is affected by the distance of the coil from the conductor, the electrical conductivity of the conductor, the permeability of the conductor, the design of the coil, the frequency of the current, and the amount of the conductor present. A change in any of these factors will produce a corresponding change in the amplitude of the coil's current.

Each shoe on the Vertilog instrument has two eddy current coils. The two coils are located so that the area of the casing that affects them is also the area that affects the flux leakage transducers.

It has been shown that an increase in the frequency of the current through the eddy current coil will reduce the depth of the metal which affects the amplitude of the current. The frequency of the eddy current used in the Vertilog instrument was selected high enough so that less than .040" of metal on the inside wall of the casing is affecting the eddy current coil. Any change in this metal thickness will cause a change in the amplitude of the current flowing through the coil.

It is this change in the current amplitude that the eddy current electronics sense. This change is recorded on the Discriminator track on the log. If the signal on the Discriminator track has a corresponding signal on FL-1 or FL-2 then the corrosion that has taken place is considered to be internal. If there is no corresponding signal on FL-1 or FL-2 then the signal is interpreted as poor pad contact.

CALIBRATIONS

Rigid calibration standards are required to insure accuracy of measurements.

Prior to logging a well the tool is calibrated. A magnetic signal of a known level is induced into each transducer. Each transducer has its own amplifier located within the instrument. Each amplifier is adjusted so that the magnetic signal induced in each transducer gives the same response on the log. This calibration procedure is necessary so that all transducers will react identically to the same anomaly.

The standard for the tool calibration is responses observed in casings of known weights with machined defects. Figure 12 shows the Horizontal Tester used to record the measurements. Casing with known defects, 15, 30, 40, 50, 60, 75, 90 percent metal loss, (as shown in Figure 13) is placed on stands at the end of the horizontal tester and the Vertilog® tool is mounted in the tester. The responses of the machined defects are recorded. Then an auxiliary calibrator is used in the field for calibration purposes.

INTERPRETATION

Before an interpretation of the log can be made certain information is helpful if available. This is the size, weight, and grade of the casing being inspected. It is also beneficial to know the size and length of the surface casing and the size and length of any intermediate string of casing that may be present.

Other information that is helpful if available is the location of centralizers, scratches, D-V collars, perforations or any other equipment that would alter the string of casing. This information should be made available to the engineer at the well site. The logging engineer will include this information when the log is submitted for interpretation.

When the log is received for interpretation, each joint of casing is numbered starting at the surface. The depth of the surface casing is marked on the log along with all other available information.

The casing will be inspected on a joint by joint basis. The FL-1 and FL-2 tracks in each joint of casing are examined for indications of the most severe damage. The full joint of casing will be graded from its weakest point. After it has been determined which is the most severe damage the Discriminator is used to determine if the corrosion is internal or external. Next the Average track is checked to determine whether corrosion is isolated or circumferential. The above damages are identified and marked on the log.

A unique advantage with the Vertilog system is that the inner strings or multiple strings can be surveyed for corrosion or other damages. This condition causes a decrease in amplitude of the signal, however, if casing configurations are known it does not cause interpretation problems. This decrease in amplitude is also true for isolated corrosion over circumferential corrosion, and external corrosion over internal corrosion.

After all four tracks have been checked the interpretation is made using charts. Charts relating the flux leakage responses to percentage metal loss are designed for each casing size, weight, and grade. Other parameters such as internal or external, isolated or circumferential corrosion, single or multiple strings are also considered in the interpretation. These charts are derived in the laboratory using machined defects as references and cross-checked with measured damages in recovered casings.

The joint of casing will then be classified either Class One, Class Two, Class Three, or Class Four. This classification will be stamped on the log to indicate the amount of damage. The four classes represent percentage of metal loss in the casing. Class One indicates less than 20% metal loss, Class Two indicates 20% to 40%, Class Three indicates 40% to 60%, and Class Four indicates over 60%. After all joints of casing have been evaluated and recorded, a final report is prepared. Figures 14, 15, and 16 are representative of the three reports included in the interpretation. Figure 14 is a brief casing record as supplied from the well history. The report summarizes the interpretation of the log with the number of joints of each class of percentage of corrosion as illustrated by Figure 15. Any unusual signals or well completion equipment will be noted in the remark section. This report also includes a listing of all joints of casing that show evidence of corrosion exceeding 20% and the type of defect that has taken place. This is illustrated by Figure 16. This interpretation along with the recorded log will give a very complete record of the condition of the casing in the well at the time of the survey.

The Vertilog alone cannot identify the cause or rate of progression of the corrosion. However, if a base log is established on a given well, subsequent inspections will evaluate the rate of progression.

There are other surveys available which may help to evaluate the condition of a given well. Since each logging survey relates to different parameters of the well, a combination of surveys will help develop an understanding of the overall condition of a well.

An Acoustic Cement Bond log will show the areas where the cement is protecting the external surface of the casing. It has been noted that external corrosion usually occurs in uncemented sections.

A Magnelog will indicate different weights of pipe where this information is unavailable. It will also locate severe damage in casing sizes for which no Vertilog tools are available.

A Casing Potential Profile will help determine the effectiveness of a cathodic protection program. If the well is in its native state, this survey will help determine the area where electro-chemical corrosion might occur.

A Sonan Survey in conjunction with a Differential Termperature survey will help locate casing leaks, and help determine the magnitude and direction of fluid movement outside the casing.

FIELD EXAMPLES

In determining the condition of casing in existing wells many examples have been documented illustrating measurements as indicated with the Vertilog® and defects confirmed after the casing was recovered.

Figures 17 and 18 are illustrations of recorded damage as confirmed with photographs of the recovered casing.

CONCLUSION

The Vertilog can be successfully used to determine the condition of the casing at the time the log is run. The Vertilog is useful in detecting and monitoring casing corrosion. This survey is an improvement of existing methods of casing inspection because of its improved sensitivity and its ability to detect and evaluate smaller anomalies. Also its surveys the complete circumference of the casing. Another advantage is that this service does not require special fluids in the borehole. The Vertilog in conjunction with other measurements will help formulate techniques to solve corrosion problems.

The Vertilog is helpful in resolving questions that might arise concerning perforated intervals or shot density.

REFERENCES

1. Bradshaw, James M. "Vertilog: A Downhole Casing Inspection Service" presented at Corrosion/76, Houston, March 22-26, 1976.

2. Cook, A. D., "Vertilog: A Downhole Inspection Service" Technical Memorandum, Vol. 7, No. 1, March 1976.

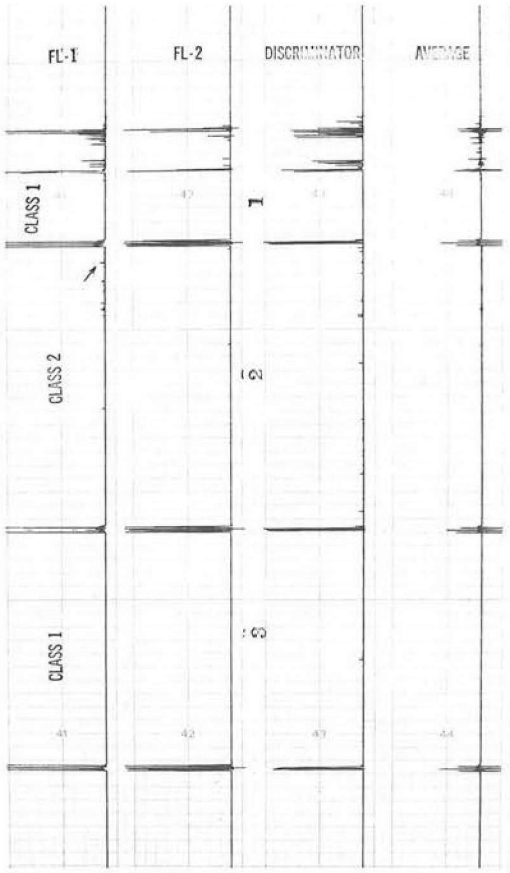


Figure 1 - Standard Vertilog Presentation

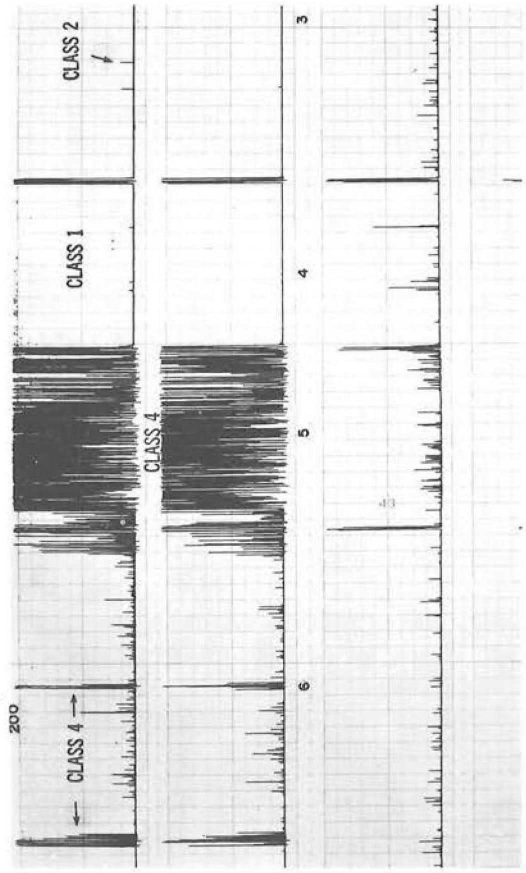


Figure 3 - Severe Casing Damage

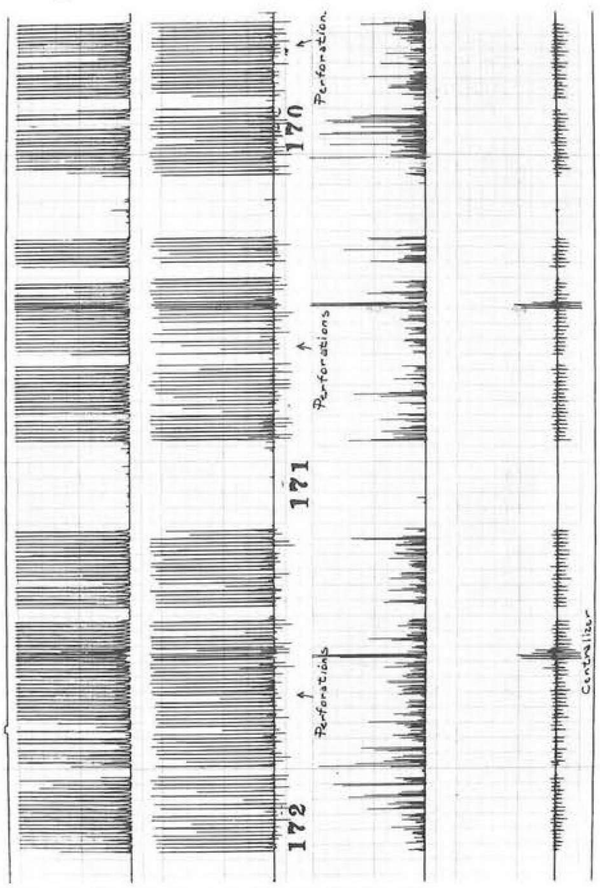


Figure 4 - Perforations As Shown By Vertilog

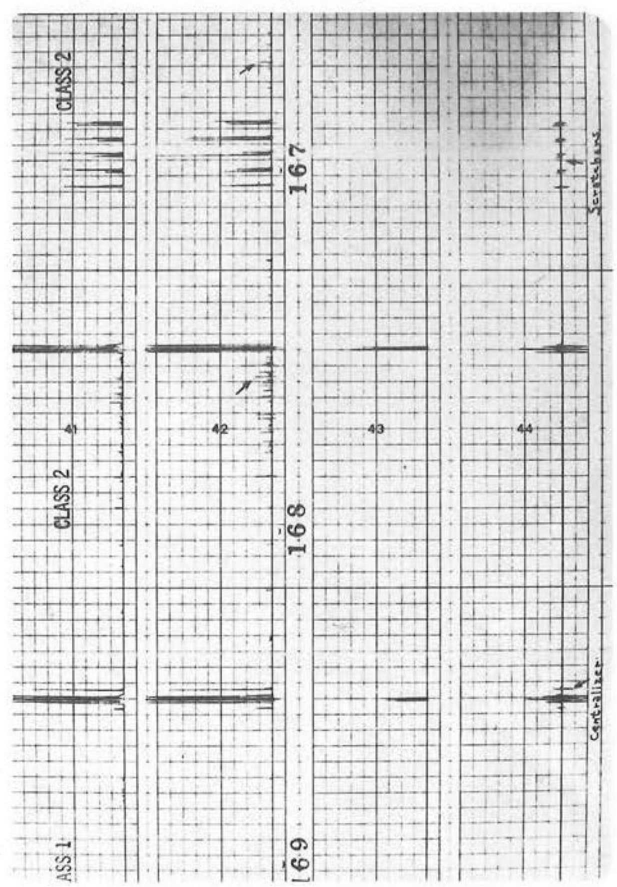


Figure 5 - Well Completion Equipment

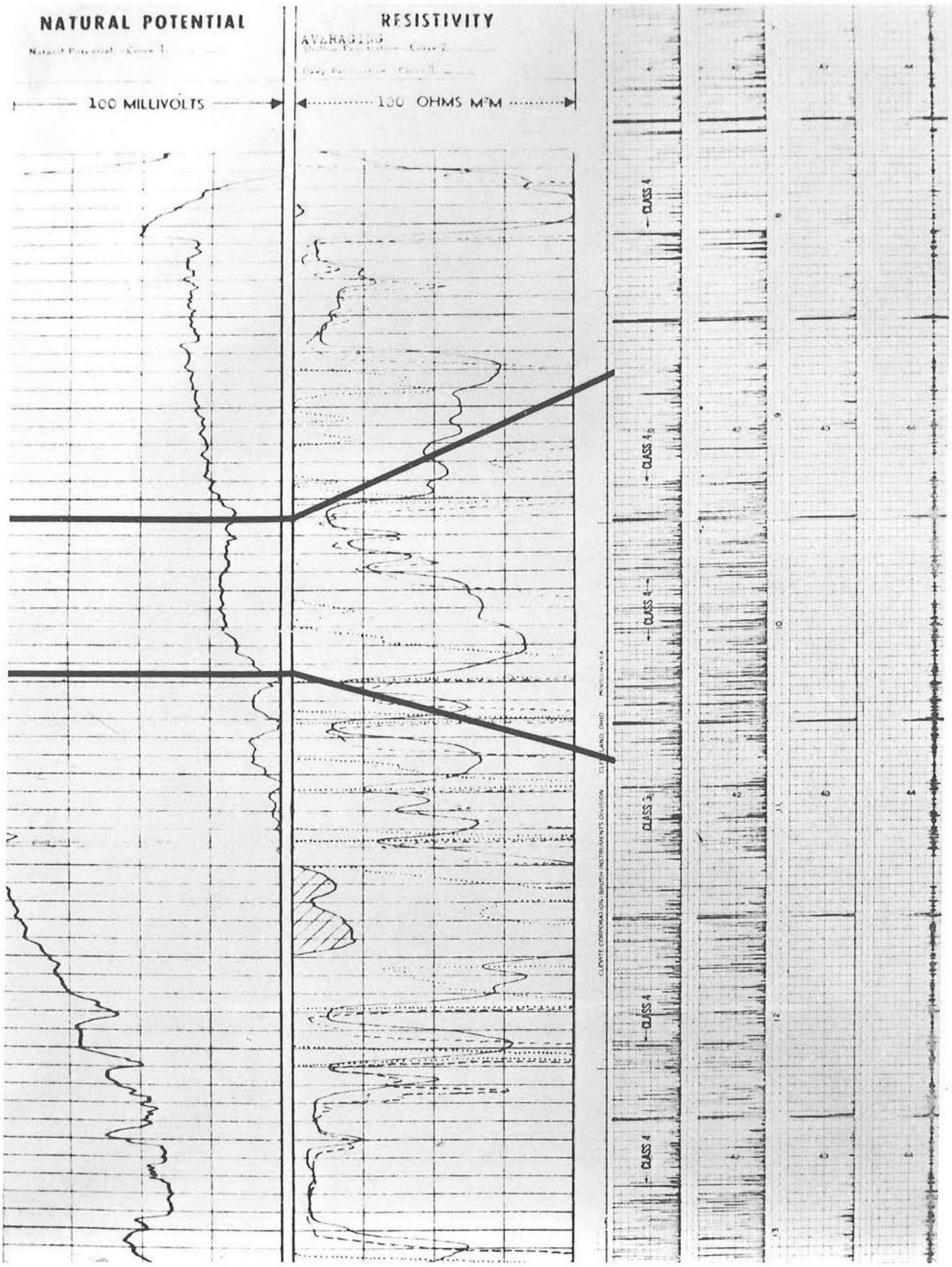
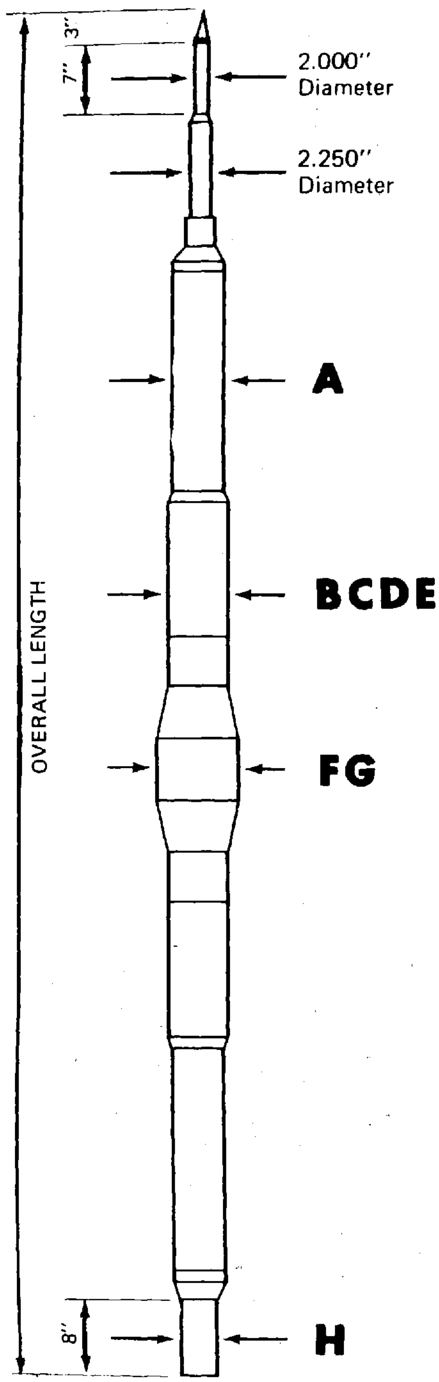


Figure 2 - Electrolog - Vertilog Comparison

Dresser Atlas
VERTILOG-DOWNHOLE CASING INSPECTION



Tool Specifications

	Specifications	4½" Tool	4½" Tool 5" Transducers	5½" Tool	5½" Tool 5" Transducers	7" Tool	8-5/8" Tool
A	Diameter	3.437	3.437	3.437	3.437	4.875	4.875
B	Diameter	3.625	3.625	4.250	4.250	5.500	7.125
C	#1 Sleeve Diameter	3.875	3.875	4.625	4.625	5.875	7.310
D	#2 Sleeve Diameter						7.500
E	#3 Sleeve Diameter						7.700
F	Minimum Diameter	3.743	3.882	4.447	4.325	5.923	7.358
G	Maximum Diameter	4.954	4.954	5.579	5.579	7.363	8.391
H	Diameter	3.438	3.438	3.438	3.438	3.438	3.438
	Approx. Weight (lbs.)	225	225	260	260	440	650

Overall Length of Tool

Specifications	4½" Tool	4½" Tool with 5" Transducers	5½" Tool	5½" Tool with 5" Transducers	7" Tool	8-5/8" Tool
No Sinker Bar	10'-10-7/32"	10'-10-7/32"	10'-10-7/32"	10'-10-7/32"	11'-1-1/32"	11'-1-9/32"
1 Sinker Bar	13'-10-7/32"	13'-10-7/32"	13'-10-7/32"	13'-10-7/32"	14'-1-1/32"	14'-1-9/32"
2 Sinker Bar	16'-10-7/32"	16'-10-7/32"	16'-10-7/32"	16'-10-7/32"	17'-1-1/32"	17'-1-9/32"
3 Sinker Bar	19'-10-7/32"	19'-10-7/32"	19'-10-7/32"	19'-10-7/32"	20'-1-1/32"	20'-1-9/32"

1 Sinker Bar weighs approximately 140 lbs.

Figure 6 - Tool Specifications

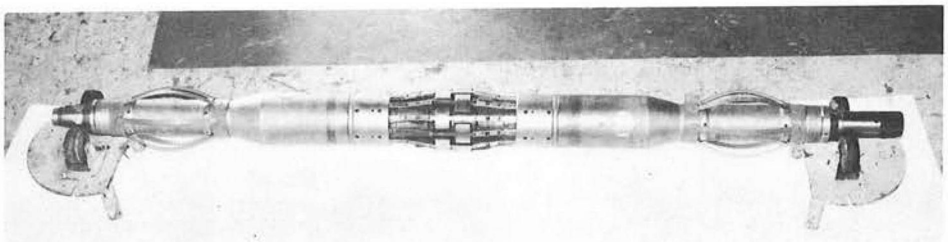
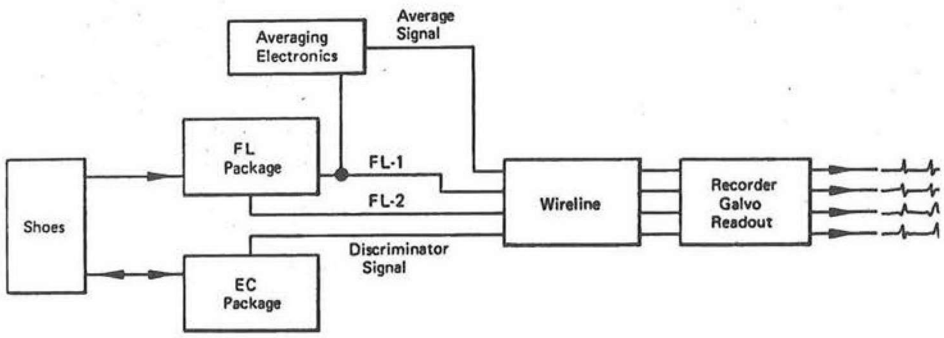


Figure 7 - 8-5/8" O.D. Vertilog Tool



Block diagram of the Vertilog® system.

Figure 8 - Block Diagram of the Vertilog System

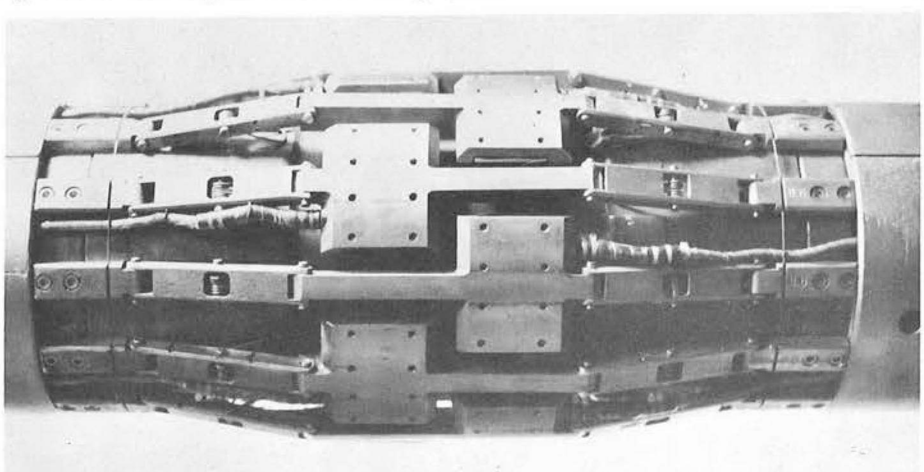


Figure 9 - Shoe Section

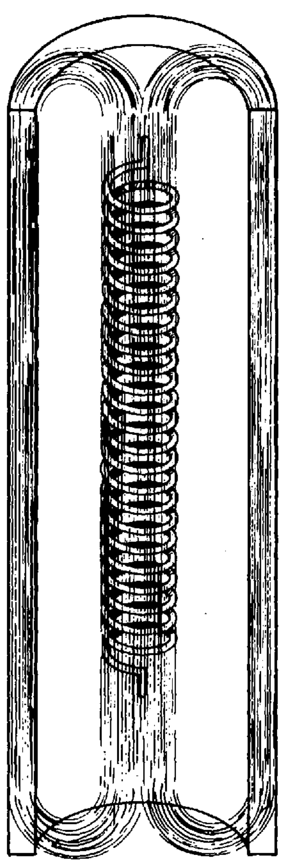


Figure 10 - Flux Lines

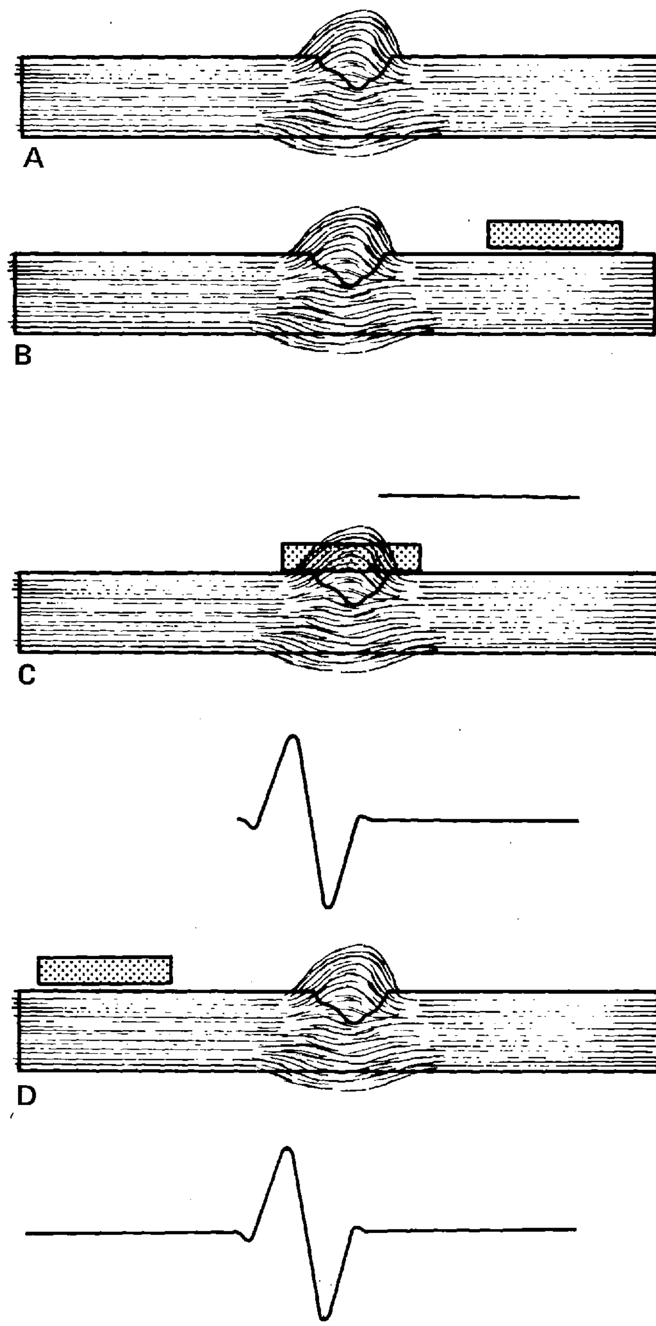


Figure 11 - (A) A Visualization of Magnetic Lines of Flux Flowing Around A Pit In Casing Bodywall, (B) The Signal Produced As A Shoe Approaches The Pit, (C) As It Passes Over The Pit, and (D) As It Leaves The Pit

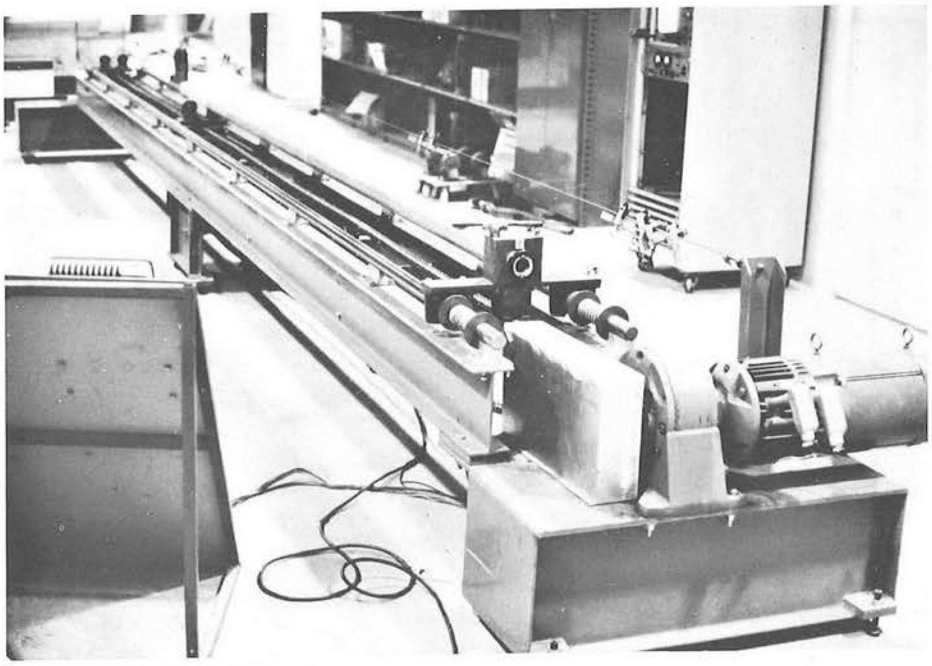


Figure 12 - Horizontal Tester

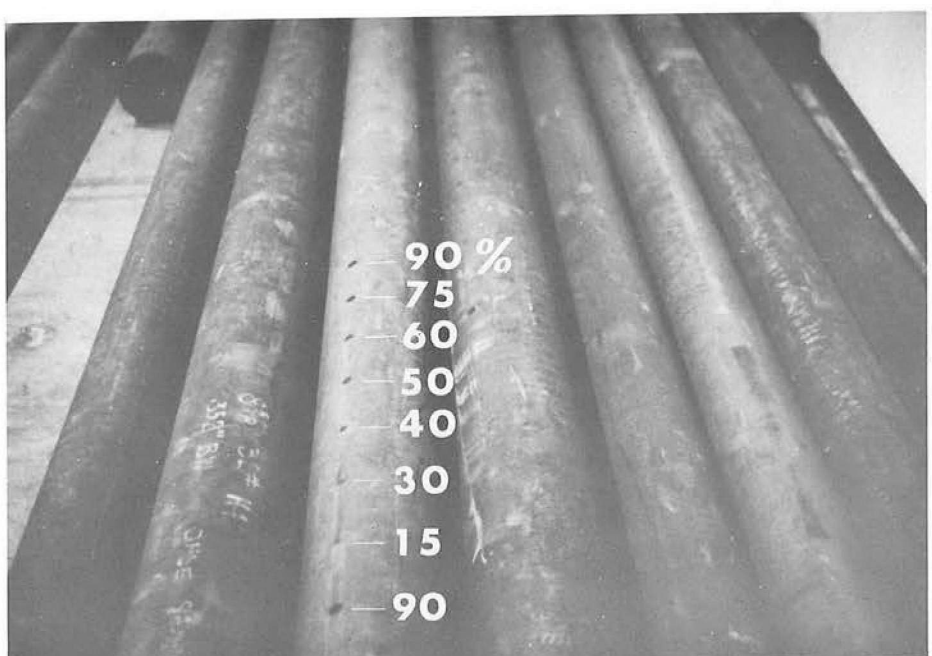


Figure 13 - Machine Defects

VERTILOG® Dresser Atlas

CUSTOMER Wildcat Oil Company		DATE 2-14-77
LEASE/WELL NO. Hope 1		
FIELD New Hope	COUNTY Kern	STATE California

CASING RECORD

DRESSER ATLAS MEASUREMENTS		CUSTOMER CASING RECORDS
10 3/4" @ 225'		10 3/4" @ 225'
7" @ 1100'		7" @ 1102'

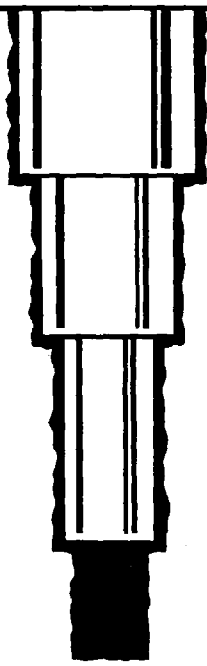


Figure 14 - Casing Record

VERTILOG® Dresser Atlas

CUSTOMER Wildcat Oil Company	WORK ORDER NO. 345	DATE 2-14-77
LEASE/WELL NO. Hope 1	CUSTOMER ORDER NO. 123	
FIELD New Hope	COUNTY Kern	STATE California
CASING O.D. 7" WEIGHT(S) 26#	NOMINAL WALL THICKNESS .362	GRADE J-55
TOTAL FOOTAGE INSPECTED 1100'	FROM Surface	TO 1100' DEPTH

SUBSURFACE CASING INSPECTION REPORT

SUMMARY

20 LENGTHS WERE FOUND TO SHOW NO EVIDENCE OF CORROSION EXCEEDING 20% PERCENT OF THE NOMINAL BODY WALL. CLASS 1

5 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 20% PERCENT BUT LESS THAN 41% PERCENT OF THE NOMINAL BODY WALL. CLASS 2

4 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 40% PERCENT BUT LESS THAN 61% PERCENT OF THE NOMINAL BODY WALL. CLASS 3

1 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 60% PERCENT OF THE NOMINAL BODY WALL. CLASS 4

30 TOTAL LENGTHS

1100' TOTAL FOOTAGE

REFERENCE FOR FOOTAGE MEASURE Surface

LENGTHS ARE NUMBERED FROM Surface

COMMENTS Length #26 and #28 appear to have centralizers located on them, if none present then Class 3 corrosion exists.

SERVICED BY

Figure 15 - Summary

VERTILOG® Dresser Atlas

CUSTOMER Wildcat Oil Company	WORK ORDER NO. 345	DATE 2-14-77
LEASE/WELL NO. Hope 1	CUSTOMER ORDER NO. 123	
FIELD New Hope	COUNTY Kern	STATE California
CASING O.D. 7" WEIGHT(S) 26#	NOMINAL WALL THICKNESS .362	GRADE J-55
TOTAL FOOTAGE INSPECTED 1100'	FROM Surface	TO 1100' DEPTH

SUBSURFACE CASING DEFECT REPORT

LENGTH NO.	TYPE DEFECT	PENETRATION	LENGTH NO.	TYPE DEFECT	PENETRATION
	Inside Surface Pipe				
3	O.D. I.P.	20-40			
5	O.D. I.P.	20-40			
	Outside Surface Pipe				
8	I.D. I.P.	40-60			
9	O.D. C.C.	40-60			
10	O.D. I.P.	20-40			
15	I.D. I.P.	20-40			
18	O.D. I.P.	20-40			
25	O.D. I.P.	40-60			
26	O.D. C.C.	40-60			
29	O.D. I.P.	over 60			

ABBREVIATIONS:
O.D. – OUTSIDE DIAMETER
I.D. – INSIDE DIAMETER
O.S. – OUTSIDE SURFACE PIPE
I.S. – INSIDE SURFACE PIPE
T.L. – THROUGHOUT LENGTH
I.P. – ISOLATED PITTING
C.C. – CIRCUMFERENTIAL CORROSION
M.C. – MINOR CORROSION
S.C. – SEVERE CORROSION

Figure 16 - Casing Defect Report

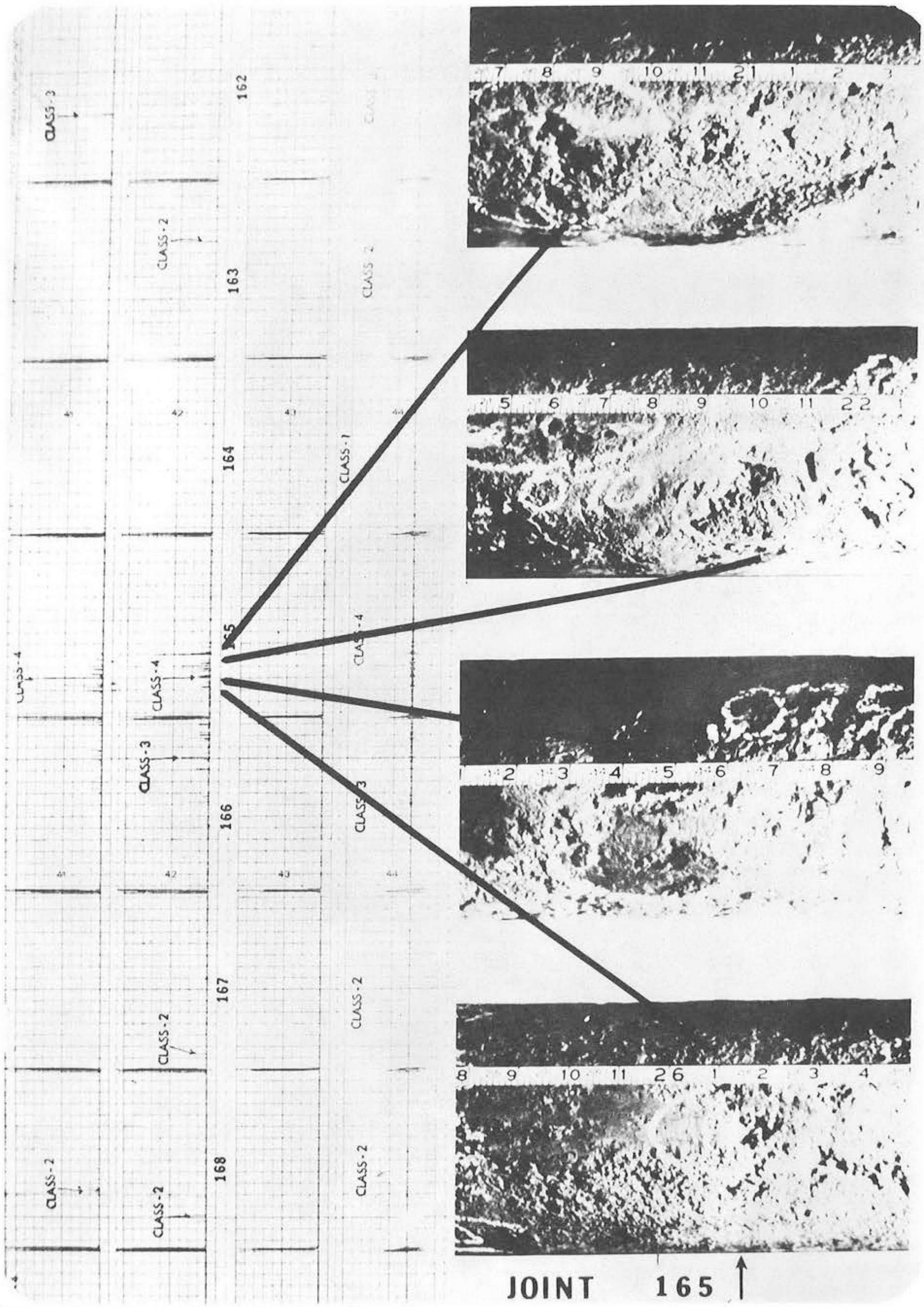


Figure 17 - Vertilog and Recovered Casing Example

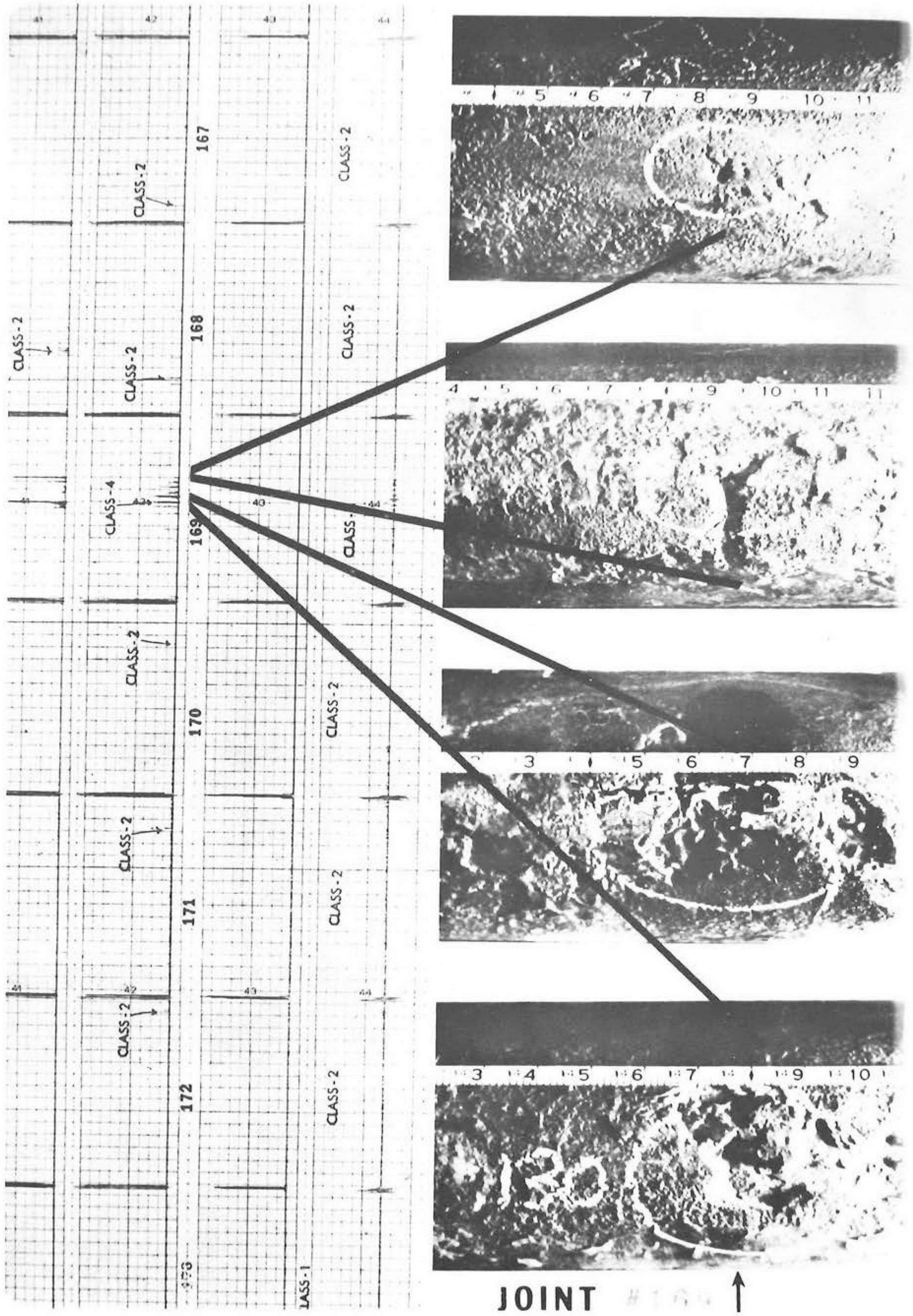


Figure 18 - Vertilog and Recovered Casing Example

Ex. II - 2

Ultrasonic Or MFL Inspection: Which Technology Is Better For You?

by **Hartmut Goedecke, GE Oil & Gas,** United Kingdom

The pipeline operator can make an informed choice as to which inspection technology to use — UT or MFL — in part by using assessment information provided in this article. GE Power Systems, Oil and Gas, PII Pipeline Solutions (PII) has more than 35 years experience in pipeline inspection using high resolution techniques and, as such, offers the industry an authoritative view of both MFL and UT technologies.

Listed here are discussions about several factors ranging from pipeline features and typical defects to operating conditions of a pipeline. The benefits of using each type of technology are outlined. Both ultrasonic (UT) and magnetic (MFL) are good inspection technologies and are available in the full range of popular pipeline diameters.

Both MFL and UT techniques offer benefits for pipeline inspection projects. Taking pipeline features and defect types into account, each technology has its strong points, and the choice of tool depends to a large extent on some knowledge of the type of defects to be encountered. In some cases, operational factors need to be balanced against performance factors. In other cases, cleaning issues in heavily waxed pipelines may make the MFL technique the more robust choice.

Tool Technologies

Depth sizing accuracy. The MFL tool measures magnetic leakage fields. The measured field strength and field extension are dependent on the depth and extension of the defect, but they also depend on other factors such as defect shape, wall thickness, magnetization, magnetic properties, and speed. The algorithms to turn the measured magnetic field into defect dimensions are based on defect-sizing models and experience and must take into account many secondary influences.

Historically, the results of the first-generation MFL tools were not very satisfactory, but BG (British Gas) and then PII developed advanced electronics and analysis algorithms and software which set new standards in the industry. Defect depth sizing now has a typical accuracy of (10 percent of wt with a confidence level of 80 percent. For a typical wt of 8 mm this would be ±0.8 mm.

The ultrasonic technique employed in PII's UT tool is used extensively in all parts of industry. Given smooth steel surfaces, this technology has a depth-sizing accuracy of 0.1 mm. In the pipeline environment, the accuracy very much depends on the surface roughness of the walls measured. The unperturbed spool wall thickness is measured locally with an accuracy of ±0.2 mm, whereas corrosion, which has usually quite rough surfaces, is measured with an average depth accuracy of ±0.5 mm at a confidence level of 95 percent. Up to 22 mm wt this accuracy is independent of wt.

Figure 2 and Figure 3 display the defect detection and sizing capability and accuracy of both tool types. The principal difference is that for MFL the accuracy is given as percent of wt, whereas for UT the numbers are in mm, independent of wt or pipe type.

This means that a performance comparison is dependent on wall thickness. Accuracy for both tools is identical at 5 mm wt, which also happens to be the lower limit of the UT wt inspection range. This means that for all wt >5 mm, UT is the more accurate technology.

Defect surface area. In both technologies data are displayed in graphical form as a multi-trace diagram or "C-Scan". Figure 1 displays the MFL and Ultrasonic data of the same spool piece. This comparison shows how the ultrasonic data relate directly to the defect surface area,

Figure 1: C-Span Comparison

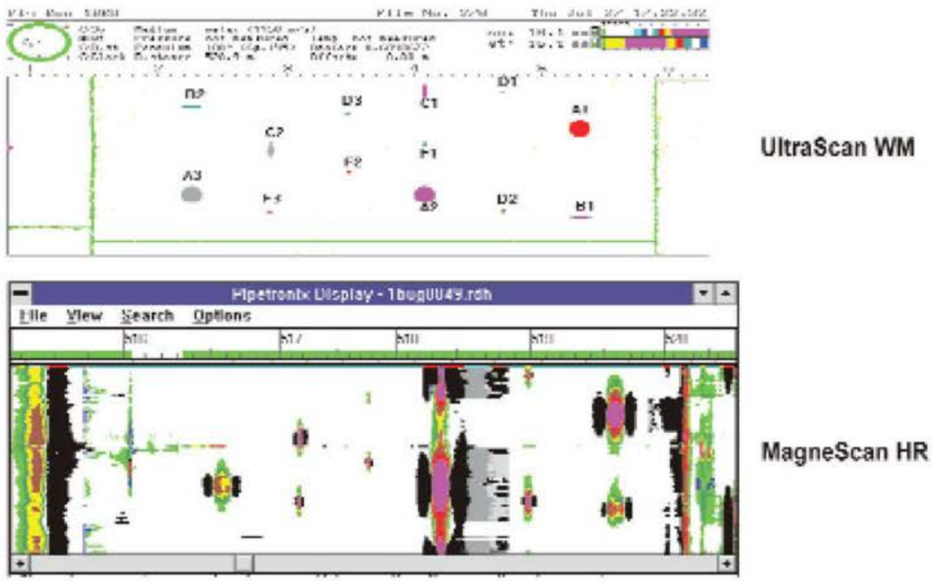


Figure 2: Magnescan - 12-56", **Manual Specification - Pipe Body**

	GENERAL METAL-LOSS @4t * 4t		PITTING @ 2t * 2t		AXIAL GROOVING		CIRCUMFERENTIAL GROOVING	
	SMLS	SW	SMLS	SW	SMLS	SW	SMLS	SW
Depth At Pod=90%	9%Wt	5%WT	13%WT	8%WT	13%WT	8%WT	9%WT	5%WT
Depth Sizing Accuracy At 80% Confidence	10%Wt	+10%WT	10%WT	+10%WT	-15% / +10%WT	-15% / +10%WT	-10% / +15%WT	-10% / +15%WT
Width Sizing Accuracy At 80% Confidence	20mm	+20mm	20mm	+20mm	20mm	+20mm	20mm	+20mm
Length Sizing Accuracy At 80% Confidence	20mm	+20mm	20mm	+10mm	20mm	+20mm	20mm	+20mm

whereas the magnetic data cover a much wider surface area that require a complicated sizing function to enable a prediction of the surface area.

This demonstrates a basic difference in the technologies. For MFL the data analysis has to take many secondary effects including defect shape into account, whereas for ultrasonics the defect dimensions can be deduced directly from the data because they are based on direct wt measurement.

Confidence Level. The confidence level for defect depth sizing is higher for UT at 95 percent vs. 80 percent for the MFL data. This means that in addition to having a higher accuracy, the UT results will be within this accuracy more often.

Figure 3: General Inspection in 5 mm to 22 mm Wall Thickness Pipeline - PII Standard -

	Pitting with diameter 10 mm (all pipe types)	Pitting with diameter 20 mm (all pipe types)		Axial Grooving	Circumferential Grooving	Lamination Fabricated or HIC
Min. Depth at POD = 90%	1.5 mm	1 mm	1 mm	1 mm	1 mm	1 mm
Depth Sizing Accuracy at 95% Confidence	Detection only	0.5 mm	?0.5 mm	0.5 mm	0.5 mm	0.5 mm
Width Sizing Accuracy at 85% Confidence	12 mm	12 mm	12 mm	12 mm	12 mm	12 mm
Length Sizing Accuracy at 85% Confidence	6 mm at 1 m/sec	6 mm at 1 m/sec	6 mm or 1% of length at 1 m/sec	6 mm or 1% of length at 1 m/sec	6 mm at 1 m/sec	6 mm at 1 m/sec or 1% of length

Note: POD = Probability of detection; POI = Probability of identification

Pipeline Features

Next, we should consider the features of a pipeline, inasmuch as MFL and UT technology operate better in different types of pipeline.

Thick wall. To achieve the optimum inspection results with the MFL technology, the pipe wall must be fully saturated with magnetic field. For thicker walls, the magnets need to be stronger and take up more volume. In smaller diameter tools, only magnets up to a certain size can be fitted, which limits the wt capability of these MFL tools.

Typical wt capabilities range from 8 mm for a 6-inch tool to 38 mm for a 42-inch XHR tool. Ultrasonic tools, on the other hand, can inspect wt up to 45 mm, independent of tool diameter. For lines with thick wall, especially in the small diameter range, the UT tool is the right choice.

Thin wall. The direct wall thickness measurement capability of the ultrasonic system now only works for remaining wt values of 2.5 mm and above, and thinner wall can only be measured when the second echo can be detected.

This means that external defects with less than 2.5 mm wt remaining may only be reported as "very deep with remaining wt less than 2.5mm." For internal defects the defect depth can always be measured via the stand off, so this restriction does not apply. Due to this restriction the application of the UT tool for lines with nominal wt below 5 mm is not feasible. For thin-wall pipes with deep external defects, the MFL tool is the right choice.

Diameter variations and dual diameter. Based on their sensor carrier design, the UT tools can cope with relatively large internal diameter variations, such as ±10 to ±15 percent for standard tool designs. For MFL tools, this figure varies from ±5 to ±10 percent.

There are dual-diameter tool designs for both tool technologies that cover large variations in nominal pipe diameter, like 25 percent for UT or 15 to 20 percent for MFL. Although there are several dual-diameter kits for these applications available for MFL tools, the UT tool design still offers the advantage that the dual-diameter capability can be obtained relatively easy as a variation of an existing tool in any diameter, thereby improving the availability and economy for dual-diameter applications.

Stainless steel and cladded pipe. Stainless steel has low magnetic permeability and can therefore not be inspected with MFL technology. In pipelines with stainless steel cladding, the carbon steel wall can be magnetized by the MFL tool, but the cladding causes a sensor liftoff which reduces the signal picked up by the sensor.

For stainless steel and cladded pipelines, the UT technology can be employed without problems, as long as the cladding is firmly bonded to the carbon steel, which is usually the case.

Seamless pipe. Two typical features of seamless pipes are varying general wall thickness and local wall thickness patterns, which are typical for the production process. In the MFL data analysis, the recorded signals are set in relation to the wall thickness of the pipe joint. The fact that this wall thickness is only known as a nominal value within a very wide tolerance band causes the MFL inspection results to be less accurate for seamless pipe than for seam-welded pipe.

Additionally, the local wt patterns cause a background signal level, which tends to hide shallow defects. Consequently, the detection threshold is higher in seamless pipe. The UT tool constantly records the true wall thickness of the pipe. Manufacturing patterns are displayed and easily recognized.

Defects are measured accurately in conjunction with the real local wt. This means that during analysis, the depth can be related to the true wt such that many quite deep defects, which happen to be in a portion of thicker wall, turn out to be harmless, and shallow defects in thinner wall are more dangerous than expected. In these circumstances, UT can be the best-suited technology for seamless pipe.

Special Defects

There are some kinds of defects, which can be detected by one technology but not by the other. On one hand, MFL tools do not see defects which cause no leakage field, and on the other hand, UT tools do not detect defects which are smaller than the ultrasonic beam.

Lamination and blisters. Lamination is a classical case of a defect which cannot be detected by MFL, but which shows up clearly in the UT data. One particular strength of UT is the detection of HIC-related lamination and blistering. MFL tools are capable of indicating sloping lamination penetrating the inner or outer pipe surface.

Very small pittings. Pittings need to be above 20 mm diameter (or above 10 mm for the pitting tool) to be measured reliably with the UT tool. For thin wall pipe with 5 mm wt this relates to a threshold size of 4t (or 2t respectively) (t=wt). The MFL tool, on the other hand, can detect and measure pittings down to 7 mm diameter (or 0.4t for thick wall). This is another reason why MFL tools are particularly suited for thin wall pipe or small diameter pitting.

Channeling corrosion. MFL tools measure mainly the change of magnetic stray flux. This means that for long and shallow defects they see only the beginning and end of the defect and it is difficult to determine the depth correctly. UT tools measure the correct wt of longitudinal channeling corrosion over the entire length. The TranScan TFI tool, a magnetic tool with transverse magnetization, also detects this type of defect very well. This tool will find very narrow channels and longitudinal cracks which are open to the surface.

Cracks in girth welds. MFL tools are capable of detecting radial cracks in the circumferential girth welds. These often arise as manufacturing defects due to poor welding procedures. The UT tool

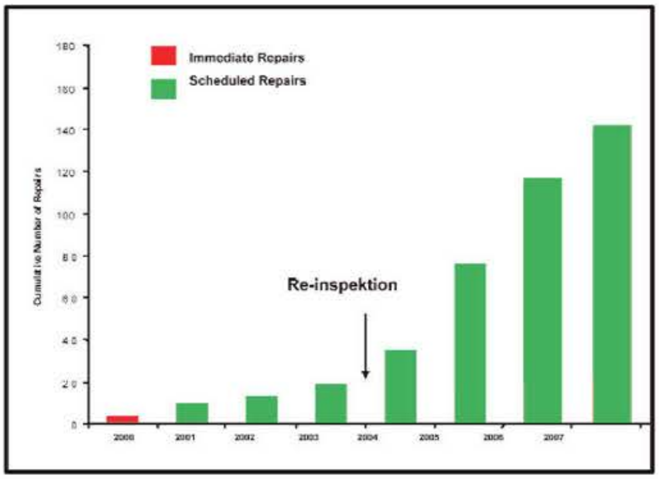


Figure 4

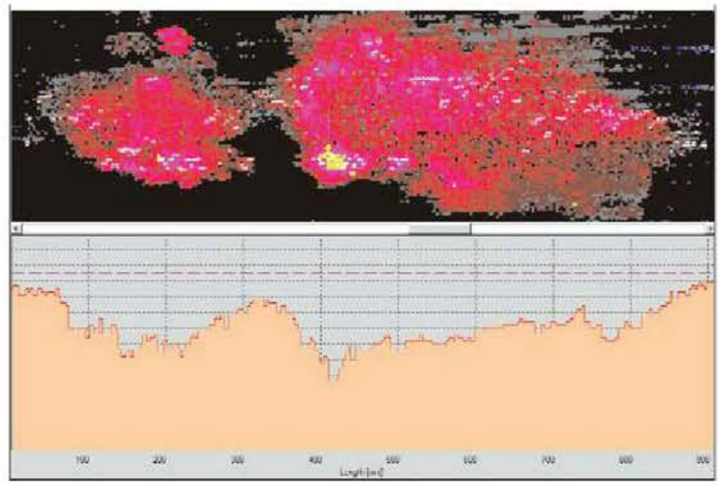


Figure 5

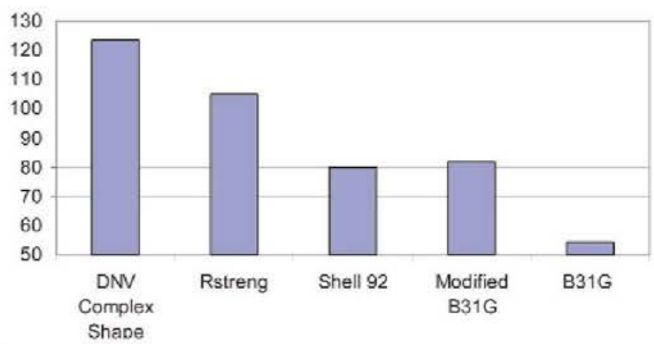


Figure 6

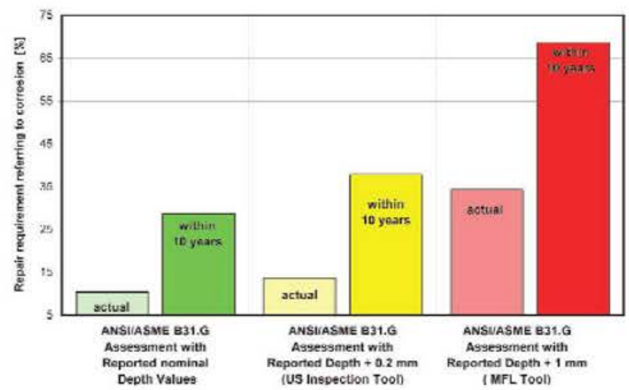


Figure 7: Influence of the degree of accuracy with respect to corrosion depth on actual and long term repair requirement. (BAsis: Inspection results of a corroded pipeline)

cannot see this kind of defect.

Grinding metal loss. Repair grindings sometimes have considerable metal loss associated and should be taken note of. Grindings are difficult to detect or size with MFL because the transitions are smooth, the wt change is very gradual and the grinder can significantly change the magnetic properties of the remaining steel. The UT direct wt measurement is better suited for detecting this type of defect.

Baseline surveys. Inspecting a brand new pipeline with an intelligent tool can be very advantageous for the pipeline owner because any irregularities found can be corrected under the guarantee clause.

Using a UT tool, the spool wt (specially seamless) can be accurately checked and defects like lamination or metal loss, misalignments, repair grindings and others reported. This is also an effective quality check of the manufacturing and construction process.

Small irregularities, which do not affect the structural strength and have passed the hydro test, can be passed over as save during later inspections.

Operating Conditions

The operating conditions within a pipeline are extremely important to find the appropriate type of technology.

Speed. MFL and UT tools operate over different speed ranges.

This range is typically:

- 0.3 to 5 m/sec for MFL, and
- 0.1 to 1 m/sec for UT, with 2 m/sec as an option for some UT sizes.

For gas lines, where the speed is considerably higher than in liquid lines, the MFL tools are again more suitable. Additionally, a bypass speed control unit is available for large diameter MFL tools (>24 inches), thus extending the applicable speed range for that tool type up to 12 m/sec.

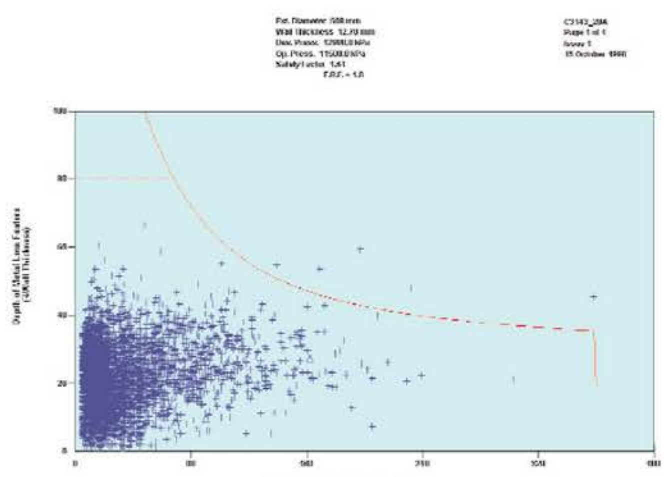


Figure 8

Liquid lines operate at 1 to 2 m/sec, with 3 m/sec as exception. Lines are generally slowed down to 1 m/sec for an UT inspection. When this is not possible, a MFL tool should be run. The next generation of UT tools will operate at higher speeds.

The very low speeds of some liquid lines do not present a problem to UT tools, but would at the moment for MFL tools. The next generation of MFL tools will operate at lower speeds.

Pressure. Gas lines operate at pressures

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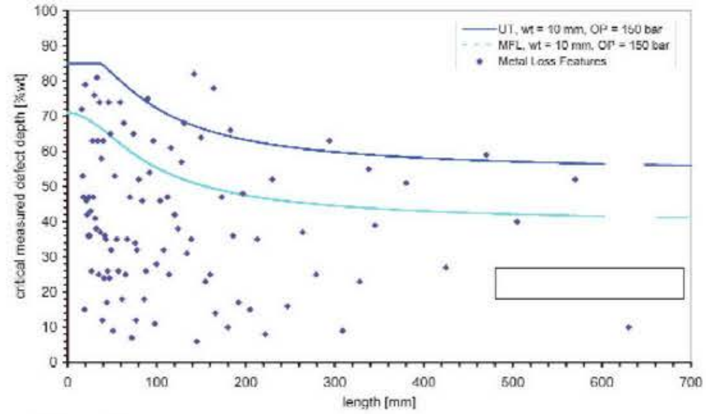

Figure 9

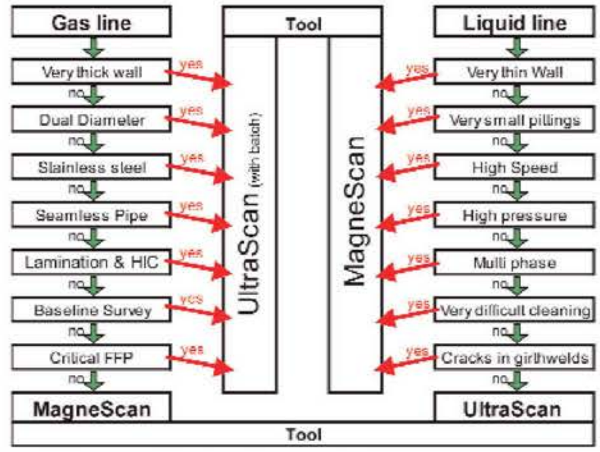

Figure 10: Choosing the right tool.

as high as 200 bar, whereas liquid lines usually are not run above 80 to 100 bar. Consequently, MFL and UT tools are designed for 220 bar and 120 bar respectively. The 120 bar pressure rating of the UT tool may restrict its use in some offshore high pressure gathering lines.

Advanced FFP

Fitness For Purpose (FFP) Calculations. When an inspection shows that a pipeline has areas of corrosion, the next task is to determine the influence of the corrosion on the safe operation of the line. The general aim is to calculate the safe operating pressure for each defect, and then only repair those defects, which are a safety hazard, and continue operating the line with the presence of the harmless defects. Repeat runs after periods of time will provide data to determine the corrosion growth, which can then be used to design repair programs with the least repairs for future years. At the point where annual repair cost takes a sharp rise, it becomes economical to carry out a re-inspection to re-evaluate the remaining corrosion and update the corrosion growth data, Figure 4.

The accuracy and confidence level of the inspection data have an important influence on the economy of the repair and rehabilitation programs.

Assessment codes. The most commonly used code is ANSI/ASME B31 G.

However, this code provides overly conservative answers, and in the case of pipelines with many defects, the number of repairs according to B31 G can be substantial, and it is more economical to use more advanced assessment codes such as RSTRENG or DNV RP F 101, which are less conservative.

Figure 6 provides a comparison of the results: for a given defect (Figure 5) the safe operating pressure according to B31 G is the lowest, whereas the DNV RP F 101 code provides a much higher safe operating pressure. Assuming the line to operate at 110 bar would mean a repair according to the B31 G and RSTRENG codes, but no repair according to the DNV code.

The RSTRENG and DNV codes need more information on the defect than B31 G, the most important being the profile of the defect. The ultrasonic method provides an accurate and detailed profile of the defects. Therefore, UT data are very well- suited for these advanced assessment codes.

Accounting for accuracy and confidence level. Inspection data have tolerances and in order to provide safe FFP calculations these tolerance levels must be taken into account. The magnitude of the tolerance affects the amount of rehabilitation and repair work as shown in Figure 7. The chart shows the immediate repairs and the repairs within the next 10 years, using the nominal depth values as a reference, as shown in the left section of the chart.

The middle and right sections show the repairs required with the tolerances of different tool types taken into account. The best tolerances result in the least repairs, which means money saved in the repair program. In some cases, pipelines have been evaluated with over 1 million corrosion defects. In these cases, statistical methods are used to cope with the wealth of data.

It is customary to display defects in a pressure-sentenced plot, as shown in Figure 8. An acceptance curve, which is generated according to the assessment code used, separates the defects that can be accepted without repair from those that must be repaired at the given operating pressure. The shown chart is based on B31G with nominal defect dimensions entered. To allow for tolerances caused by accuracy and confidence level, one option would be to recalculate all defect dimensions accordingly, which is very tedious.

A better way is to calculate a designated acceptance curve for each set of accuracy and confidence values. DNV RP F 101 includes such a procedure — the acceptance curves for MFL and UT tools are shown in Figure 9 for a pipe with 10 mm wt. The curve corresponding to the tool with the lower accuracy has the lower position on the graph, which means a group of deeper defects, which can be accepted when they are measured by the more accurate tool, cannot be accepted when measured by the lower accuracy tool. Again the data set with the smaller tolerances leads to fewer repairs.

Conclusions

For all defect assessment and growth calculations the tool with the higher depth-sizing accuracy — the UT tool — offers substantial savings to the customer by reducing the number of necessary repairs and stretching repair programs over longer time periods.

The MFL tool, on the other hand, offers big advantages from the operational point of view for surveys in gas lines. Here, the UT tool needs to be run in liquid batches, a process which adds cost to a survey project. The UT tool also generally needs a cleaner line than the MFL tool, which could affect the economy of the inspection project in very difficult-to-clean crude oil pipelines. It is therefore recommended to first consider the MFL tool for all gas lines, and the UT tool for all liquid line projects. ***P&GJ***

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Ex. II - 3

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Full-Signature Multiple-Channel Vertilog

G.W. Adams and W.D. Moffat, Atlas Wireline Services

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ABSTRACT

A new version of the Vertilog flux leakage (DC Magnetic Inspection) pipe evaluation tool has been developed. This new system is called the Digital Vertilog (DV). This paper presents an explanation of the DV tool theory, operating system and its working components. The sensor system of the standard Vertilog has been provided with an updated data gathering system in order to increase the information available to the log analyst. This new system transmits true bi-polar representations of each flux leakage sensor and a number of eddy current sensors to the surface recorder. The multiple bi-polar flux leakage (FL) channels allow easier interpretation by contrasting changes due to hardware and corrosion. Some of the features more easily determined include pitting, perforation (including the phase of gun used), scratchers, and centralizers. Log examples generated in the lab and their interpretation will be presented. These examples successfully demonstrate the advantage of recording full signature wave response and accurately differentiating pipe hardware from corrosion.

INTRODUCTION

The Vertilog pipe evaluation tool utilizes flux leakage and eddy current detectors to inspect both the inner and outer wall of the primary pipe string. Previous experimentation[1] prompted the development of a new generation of Vertilog tool. These instruments utilize downhole digital processing to provide a new element to the Vertilog survey. Switched gain circuits controlled at the surface improves the signal response. The downhole digitization of the data allows the recording of each flux leakage channel and a number of eddy current channels. This allows true circumferential inspection of the pipe. The high data rate of the system reproduces the true bi-polar characteristic of the flux leakage signals. This allows easier interpretation between hardware and corrosion. Figure 1 shows a typical casing configuration. Notice that some of the collars of the production string are surrounded by centralizers, which hold the casing centered within the wellbore. Also note that scratchers appear on the outside of some casing joints. These are used to roughen the surface of the wellbore before cementing. The Vertilog survey is recorded while moving upward within the production string. In the earlier Vertilog survey, casing hardware (e.g., scratchers and centralizers) caused responses which are similar to corrosive defect responses. Often casing records must be relied upon for identifying the log responses due to scratchers and centralizers, to insure that these responses are not misinterpreted as casing defects. If the records are accurate, casing hardware responses are not mistakenly interpreted as defects. If the records are inaccurate, casing hardware responses can be interpreted as corrosive defects. The Digital Vertilog survey provides bi-polar data channels. The additional log data permits identification of casing hardware responses without reference to the casing records. From the log data alone, corrosive defect responses can be differentiated from casing hardware responses. Even if the casing records are inaccurate, the additional log data prevents the misinterpretation of casing hardware responses as defect responses.

References and figures at end of paper.

Digital Vertilog System Overview

The Digital Vertilog tool is composed of an electromagnet and sensor assembly housed in the mandrel section and

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three electronic sections. There are four different mandrel sizes. The electronics are designed to be used with all four mandrel sizes. Figure 2 shows a Vertilog tool mandrel. The coil of the electromagnet is located under the shoes containing the sensors. The poles of the electromagnet are formed by the electronic housing of the mandrel. On the sensor section shown in Figure 3 two separate rings of shoes are mounted in an overlapping arrangement. This insures certain detection of corrosive defects.

Flux Leakage (FL)

Figure 4 shows a representation of the flux field produced by the tool's electromagnet. A DC current produced uphole is injected into the electromagnet's coil. This produces a static magnetic field in the core, which is coupled to the casing across air gaps at the tool's poles. In the example, flux lines that are not present in the casing have been omitted for clarity. In a section of casing without defects, the field is uniform. Around defects, the field is disturbed and flux lines leak out of the casing wall. The tool's FL coils respond to the flux leakage according to Maxwell's equations:

$$\oint_l E \odot dl = -\int_s \partial\beta/\partial t \odot dS + \oint_l (v \otimes \beta) \odot dl \quad (1)$$

Removing the fixed reference point and applying Stoke's theorem reduces the above equation to the point relation:

$$\nabla \otimes E = -\partial\beta/\partial t \quad (2)$$

Thus the amplitude of the coil's output is proportional to the rate of change of the magnetic flux density. Since the vector of the flux is determined by metal gain, or metal loss in the field, the coil's output will also reflect loss or gain. It has been empirically determined that an equation of the form;

$$A_1 * \ln((\nabla \otimes E) * A_2 + 1) \quad (3)$$

can be used to generate interpretation charts. The values of the "A" factors are empirically determined from data obtained from actual pipe samples.

Eddy Current (EC)

An eddy current system is used to detect changes in the internal wall of the casing being surveyed. Injecting an alternating current into a coil of wire will produce an alternating magnetic flux field around the coil. The coil is then placed parallel to a conducting material (pipe). As a magnetic field expands and collapses, small circulating currents are set up in the material. These currents, eddy or Foucault currents, are set up in a direction which resists the change in the injected flux field. The circulating currents generate their own magnetic fields of opposite polarity to the original field. These opposing fields act as a load on the coil, affecting the amplitude of the current passing through the coil. As the frequency of the AC field increases, the EC losses will increase. As the material moves further away from the coil, the loading effect decreases and the amplitude of the coil current will increase. Measuring the change in the current injected into the coil will give an indication of changes in the internal wall of the casing. As an EC coil passes an internal defect the pit wall moves away from the coil and the amplitude of the injected current increases. As the coil passes the defect, the pit wall moves towards the coil and the current returns to normal. By keeping the frequency of the injected current high, a skin effect is produced where the eddy currents set up in the casing will be present near the inner surface only.

Data Flow

Figure 5 is a block diagram of data flow in the Digital Vertilog. The diagram is broken up into three blocks, two analog circuits and digital circuitry. Each analog circuit processes up to twelve individual FL and EC circuits depending upon the size of the mandrel. Each FL coil in the mandrel is processed separately in a manner that preserves the integrity of the coil's data. Each EC coil in the mandrel is also processed separately. The individual signals are feed into the two switching circuits. This allows an analog to digital converter to access each signal individually, converting each tool signal to a 2's compliment value. The digitized signals are then accessed by a microprocessor. The processor also controls the multiplexer switching and A/D conversion. Due to the amount of data acquired and the high tool speed of the Vertilog, two processors are used to reduce the overhead that communication with the surface telemetry produces. Both of the processor's circuits are housed in a flasked sub. The control processor handles all data acquisition and data processing. The communication processor handles all telemetry operations including data transmission to the CLS (Computerized Logging System). A high speed parallel interface between the processors allows transfer of data and instructions. Each processor has a ROM for programming. The control processor also has RAM for data and supplemental program downloading. The communication processors retains data in its own internal RAM.

Sensor Configuration

Consider a Vertilog tool with six shoes, three in the upper ring and three in the lower ring. Each shoe contains two FL sensors to detect changes of magnetic flux and two EC sensors which respond only to the defects on the inside pipe wall. A vertilog shoe cross section is shown in Figure 6 where the configuration of the FL and EC sense coils arrangement can easily be seen. To ensure that no defect escapes detection, the shoes of the upper ring are in a staggered, overlapping relationship with the shoes of the lower ring, as shown in Figure 3. The Digital Vertilog is arranged to provide the signals from all twelve or twenty-four of the flux leakage sensors. Channels 1-2, 5-6 and 9-10 display the signals from the flux leakage sensors of the three shoes of the upper ring. Channels 3-4, 7-8 and 11-12 display the signals from the flux leakage sensors of the lower rings. In addition to the twelve bi-polar flux leakage signals, a Digital Vertilog provides twelve or twenty-four EC signals. The EC coil configuration is identical to the FL coil configuration.

Lab Tests

To assure both the reliability and accuracy of the Digital Vertilog, Atlas Wireline Services operates a surface calibration facility[2] at its center in Houston, Texas. This facility is used to record tool response data for calibration charts as well as all experimental data. To develop the test data for the DV survey, two separate joints of test pipe were individually positioned on the calibrator.

Log Examples

With regard to the Digital Vertilog presentation, mass changes effect the signals from the flux leakage sensor as follows:

1) A mass increase causes a positive (left) excursion of the flux leakage signal.

2) A mass decrease causes a negative (right) excursion of the flux leakage signal.

Figure 7 shows a pipe maintained as a calibration reference standard in the surface calibration facility. Typical of a reference standard, the pipe contains a series of machined defects, a regular casing collar and a flush joint collar. In addition, a casing centralizer has been placed around the regular collar and a scratcher has been placed on the pipe 1.25 feet above the flush joint collar.

Figure 8 shows the log response to this pipe. Figure 8A shows the response of the tool to the machined defects. A series of external defects are present on channels one and two. These defects are spaced six inches apart. The defects decrease in size from 90% to 20%. Six inches above the 20% defect is another 90% defect. Three inches above this defect is a 100% defect. The EC response on these two channels is to the 100% defect only. To machine internal defects of varying depths, the pipe wall is drilled through and an internal defect is machined on the opposite wall. Channels four and five respond to the internal defects. These defects exhibit the same pattern as the external defects, with the exclusion of the 100% penetration. Channels ten, eleven and twelve respond to the through holes produced during the machining process. All of the channels discussed exhibit EC response to the internal machining.

Figure 8B shows the response to a regular casing collar surrounded by a casing centralizer. The response to the centralizer shows metal gain just below ninety-six feet and metal loss at ninety-four feet. The response to the collar is characterized by five signatures. At the leading edge of the collar, a large metal gain response is first encountered. A smaller metal loss signature is shown at the edge of the lower casing. Metal gain is encountered at the edge of the upper casing. A large metal loss is encountered at the trailing edge of the collar. The final signature is the EC response to the gap between the two casings. The characteristic responses are present on all channels, showing the circumferential nature of the collar.

The tool's response to a flush joint collar is shown in Section 8C. The characteristic response of a series of three metal gain signatures is evident. The circumferential nature of the collar is also present in the tool's response.

Response to a scratcher is shown in Section 8D. A circumferential metal gain, followed by a circumferential metal loss signature is evident on all of the tool's FL signals.

Figure 9 shows a log response to the same pipe as figure 8. In this example, the casing centralizer has been moved to a location one foot above the scratcher.

The response to a regular collar is shown in Section 9A. The signature of the casing centralizer is not present.

The three sharp metal gain characteristics of a flush joint collar are still evident in Section 9B.

The scratcher's characteristic signature is present in Figure 9C.

The response to an isolated casing centralizer is easily identified in Section 9D. The response is the same as the response to a centralizer around a collar.

Figure 10 shows the log response to general corrosion. This pipe sample was pulled from a well in West Texas. A standard Vertilog survey was run on this well. The survey showed uncorroded pipe from the surface to 5572 feet. From 5572 to 5670, three casing sections were interpreted as class 4 with holes. This pipe sample was the casing section from 5604 to 5637. Visual inspection of the casing sample showed severe general corrosion on the exterior wall with five holes at different locations on the pipe. Details of the log are:

An isolated hole is present on channels one and two, shown in Section 10A.

In Section 10B annular corrosion is present on 66% of the circumference of the pipe. A hole is present on channel ten.

Section 10C shows that general corrosion is present on 33% to 66% of the external wall.

Section 10D shows that annular corrosion is present on 50% of the circumference of the pipe. A large hole is present on channel two through five.

Section 10E shows that severe annular corrosion is present on 100% of the circumference of the pipe, accompanied by a large hole.

Section 10F shows that an isolated hole is present on channels one and two.

Log Presentation

While the Digital Vertilog is ideal for identifying log responses due to corrosive defects, it is preferable to use a Computerized Logging System (CLS) generated log presentation to estimate the penetration of a defect. The generated presentation which accompanies the DV presentation, is shown in Figure 11. The ten chart division of the left hand track are reserved for the flux leakage average response, which is zero at the fifth division and increases simultaneously to the left and right. A 360 degree response is indicated by flux leakage average which covers ten chart divisions. The first five chart divisions of the right hand track are reserved for the eddy current response which is zero at the fifth division and increases to the left. The remaining fifteen chart divisions of the right hand track display the maximum flux leakage response, which is zero at the fifth division and increases to the right. For estimating penetration depth, the generated log is preferred because it offers more resolution than the DV presentation. To estimate the penetration depth of a defect, first determine the number of Vertilog units associated with the maximum flux leakage response, then:

1) Determine the casing O.D., weight and grade.

2) Determine whether the defect is inside or outside (an inside defect is accompanied by an EC response)

3) Is it an isolated pit or general corrosion.

4) Determine whether the defect is inside the surface pipe logging interval. If so, determine the O.D. of the outside casing.

Data charts are available for converting the maximum flux leakage response to a corresponding percent penetration. The value of the percent penetration depends on the condition summarized above. Figure 12 is the chart which is appropriate to the conditions enumerated in 1 - 4. The chart shows the percent penetration which corresponds to the number of Vertilog units of the maximum flux leakage.

CONCLUSION

The ability of the tested Digital Vertilog to transmit the entire signal as seen by the sensor coil provides an opportunity to better understand the condition of casing in a well. Corrosion is readily differentiated from completion equipment like scratchers and centralizers. Collars can be studied; the physical size of the collar and the location of the ends of the two joints of casing that are joined by the collar can be examined. Detailed analysis of the sensor signal itself (signal width, rise time, area, etc.) provides more information regarding the physical parameters of the anomaly. These types of studies which can be done have previously be unavailable in the industry. It has been demonstrated that analyzing the entire sensor signal enhances the ability to interpret anomalies responses in a pipe, whether they are equipment or corrosion.

NOMENCLATURE

$\partial/\partial x$	≡	partial derivative with respect to x
$\oint_l$	≡	line integral around a closed curve
$\int_s$	≡	area integral over a specified surface
$\odot$	≡	scalar product
$\otimes$	≡	vector product
∇	≡	gradient operator
ln	≡	natural logarithm to the base e = 2.718281828...
l	≡	linear displacement in meters
t	≡	time in seconds
S	≡	surface area in meters^2
v	≡	velocity in meters/second
E	≡	electric field strength vector in volts/meter
β	≡	magnetic flux density vector in tesla

%Penetration ≡ depth of a corrosive defect in percent of total nominal wall thickness

A_1 , A_2 ≡ dimensionless correlation coefficients

ACKNOWLEDGEMENT

Cooperation from J. McCarter and Dr. J. Hwang of Atlas Wireline Services, Houston, for supplying data for this project is gratefully acknowledged. The authors also wish to thank the management of AWS Technology department for permission to publish this work.

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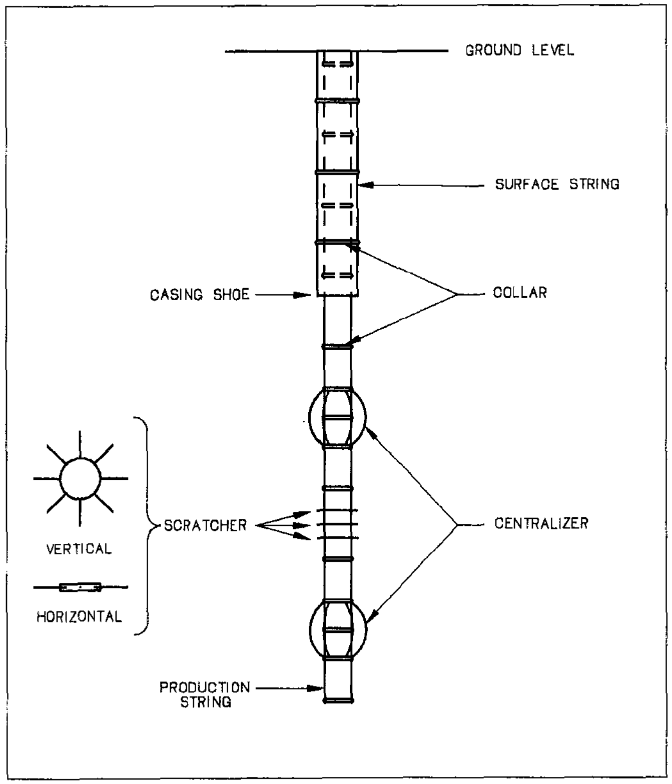

Fig. 1—Typical casing configuration in a well.

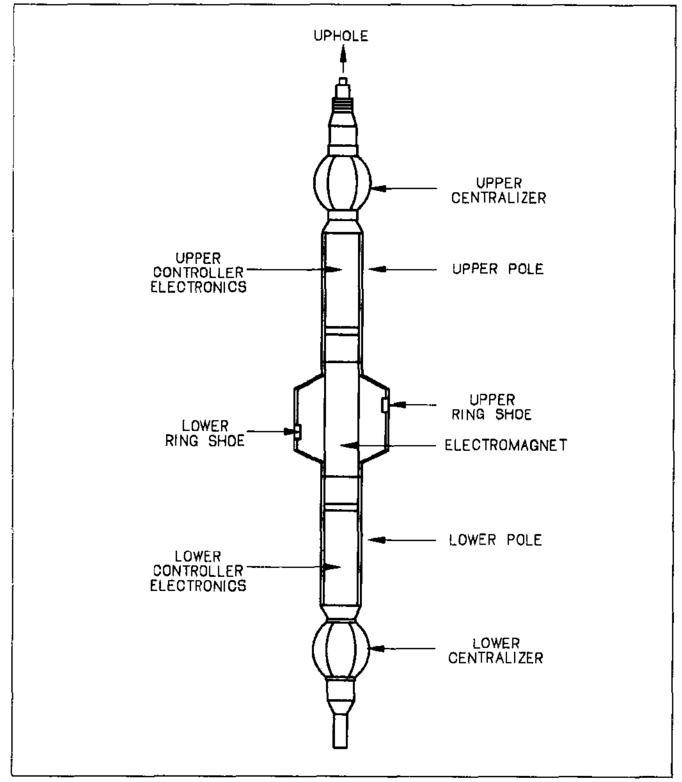

Fig. 2—Vertilog tool mandrel.

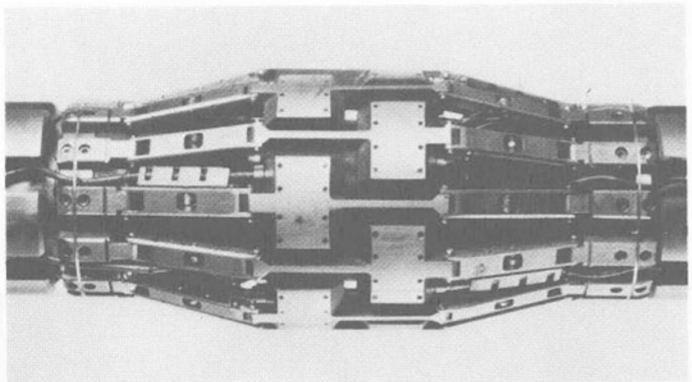

Fig. 3—Vertilog tool sensor section.

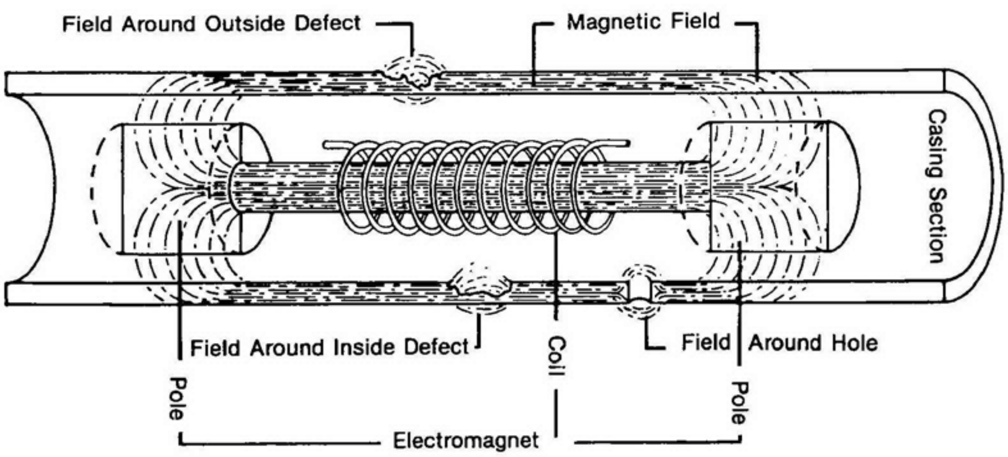

Fig. 4—Vertilog tool flux field.

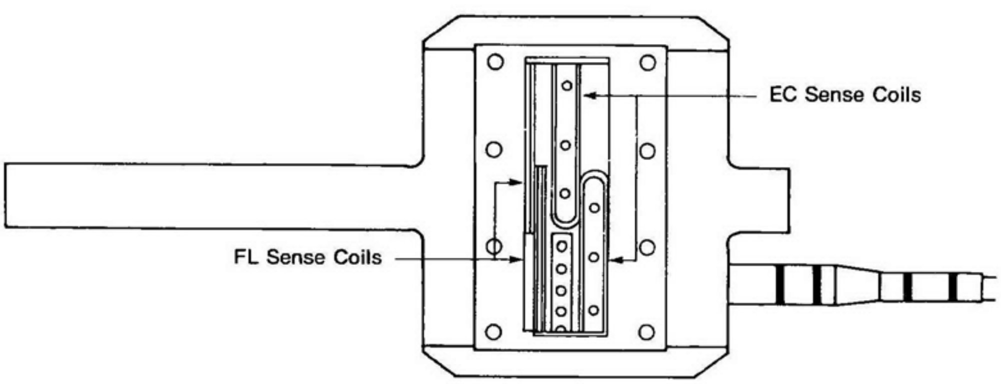

Fig. 5—Vertilog sensor pad.

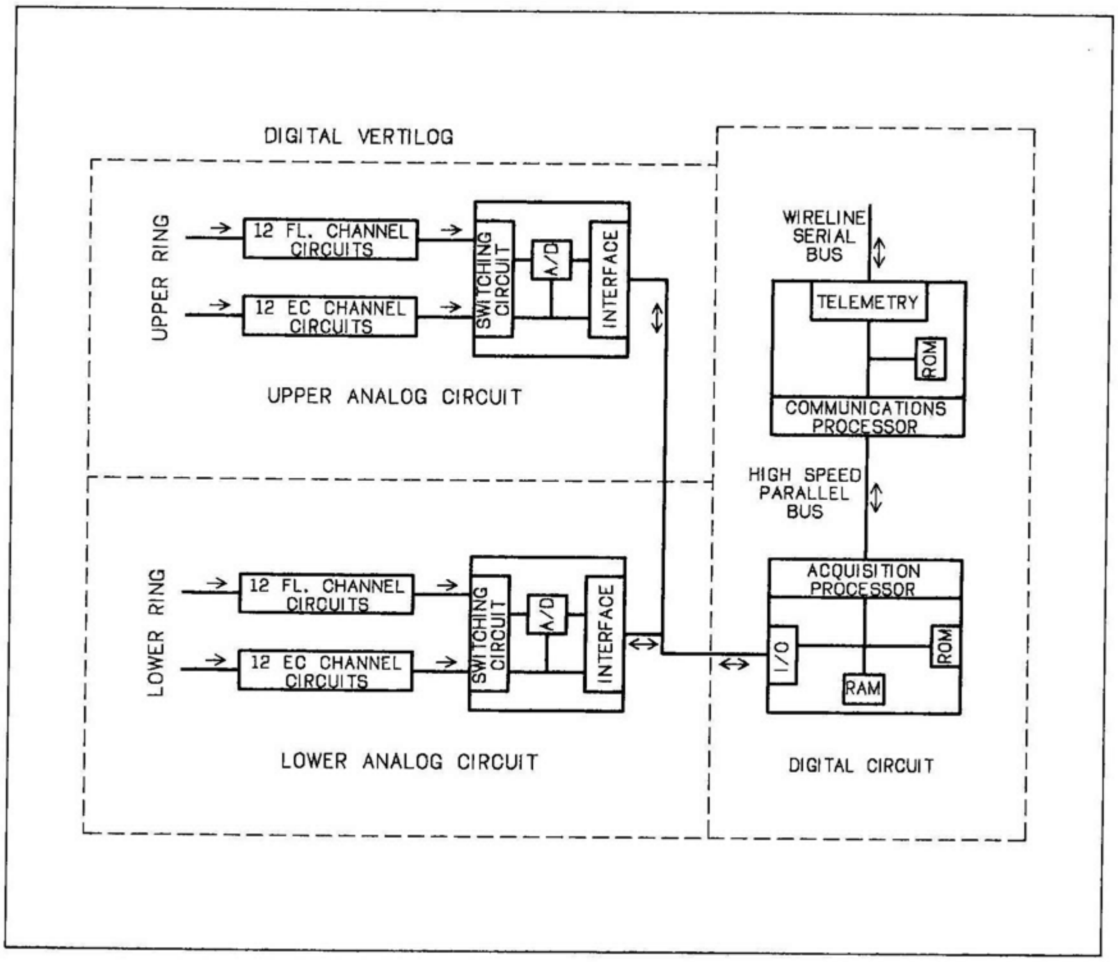

Fig. 6—Block diagram of data flow.

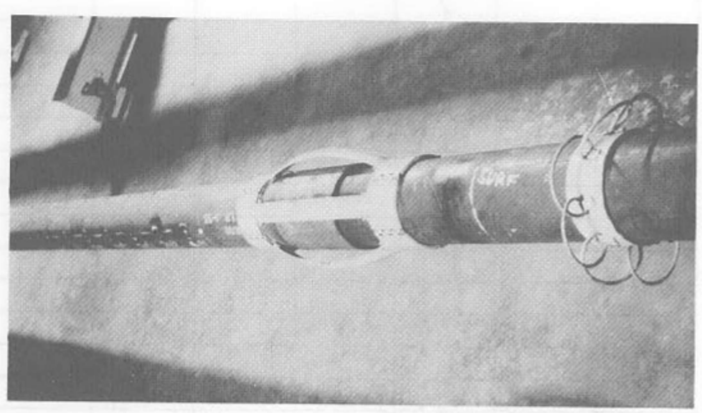

Fig. 7—Test pipe setup.

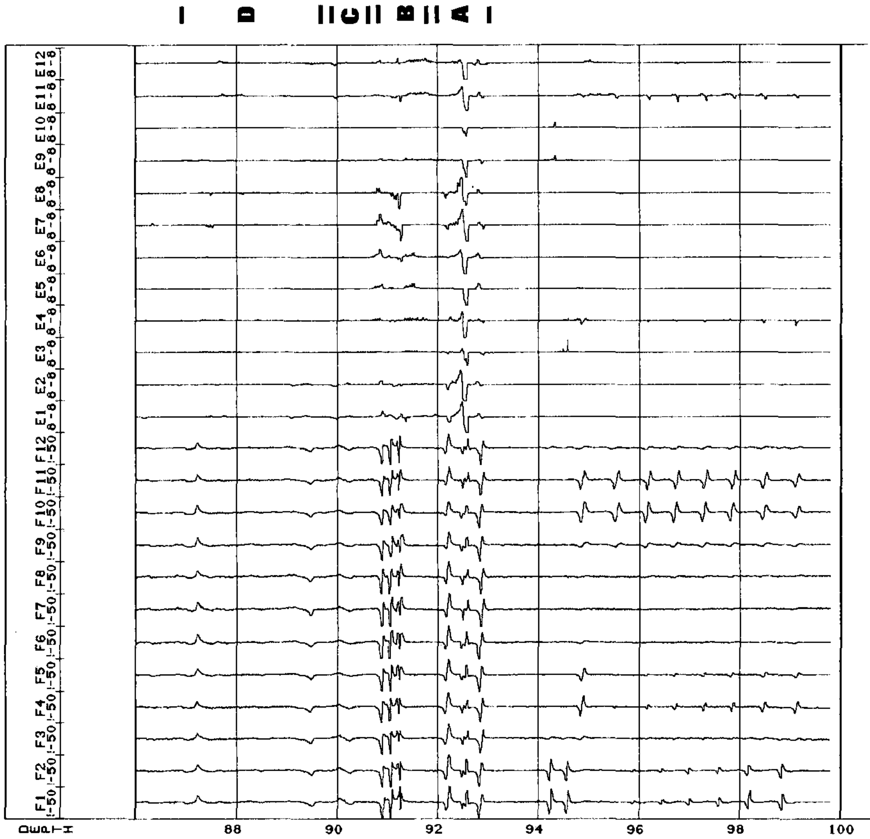

Fig. 9—Log response to test pipe.

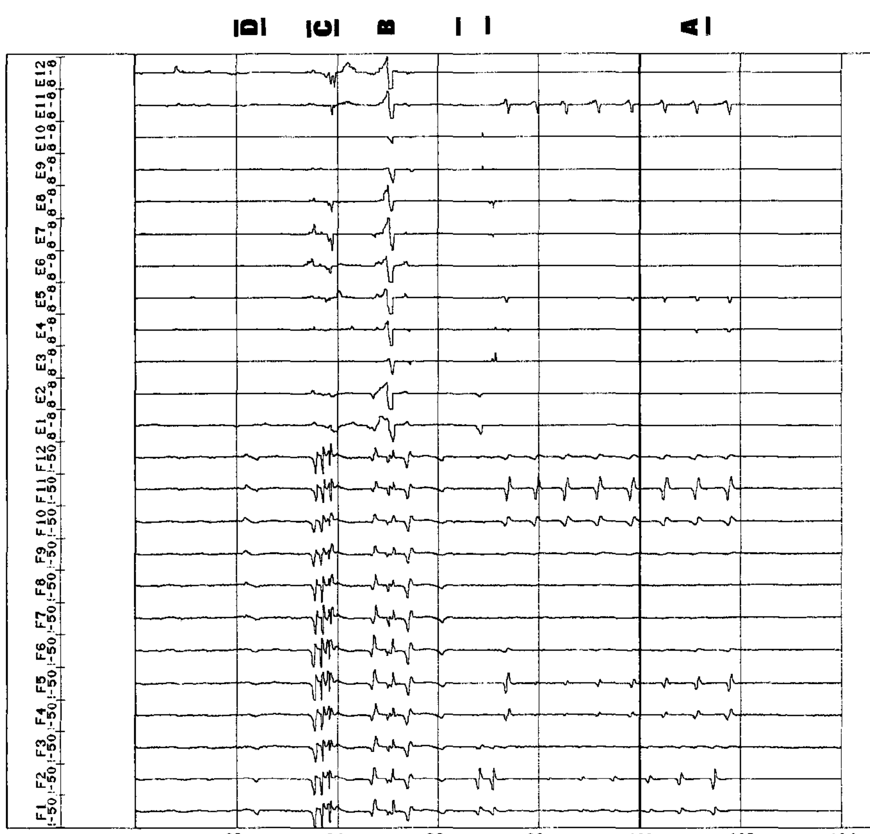

Fig. 8—Log response to test pipe.

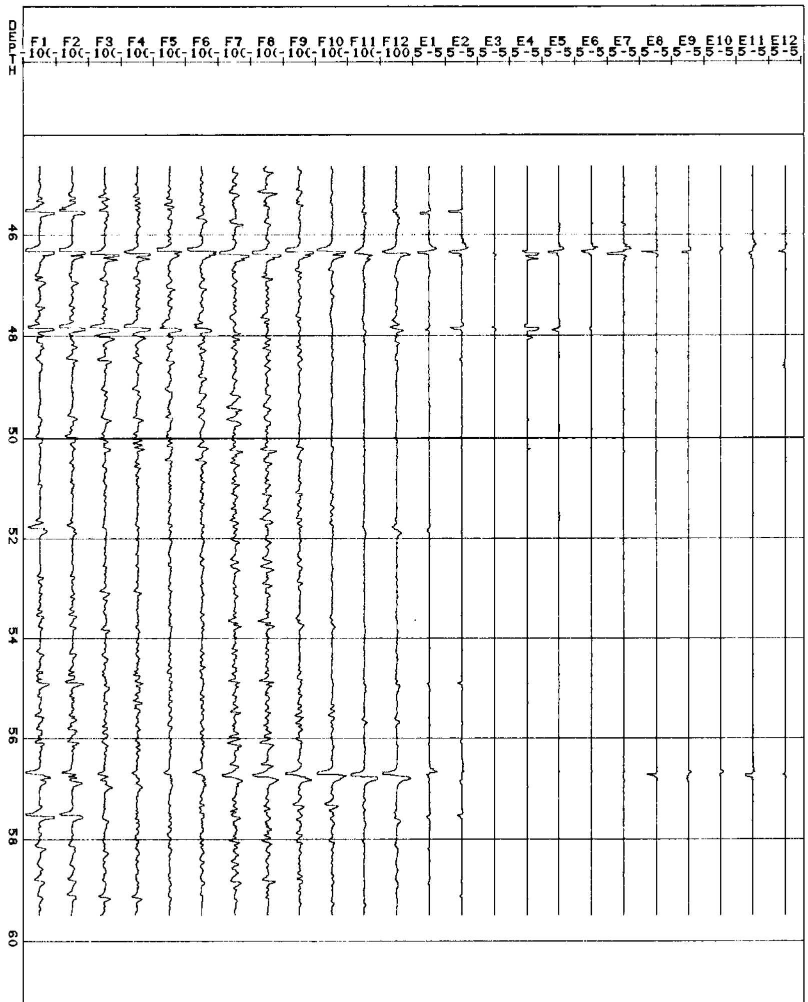

Fig. 10—Log response to general corrosion.

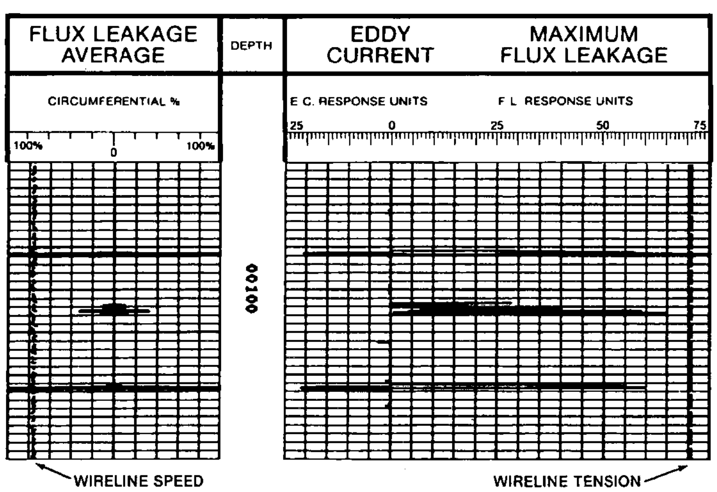

Fig. 11—Standard log presentation.

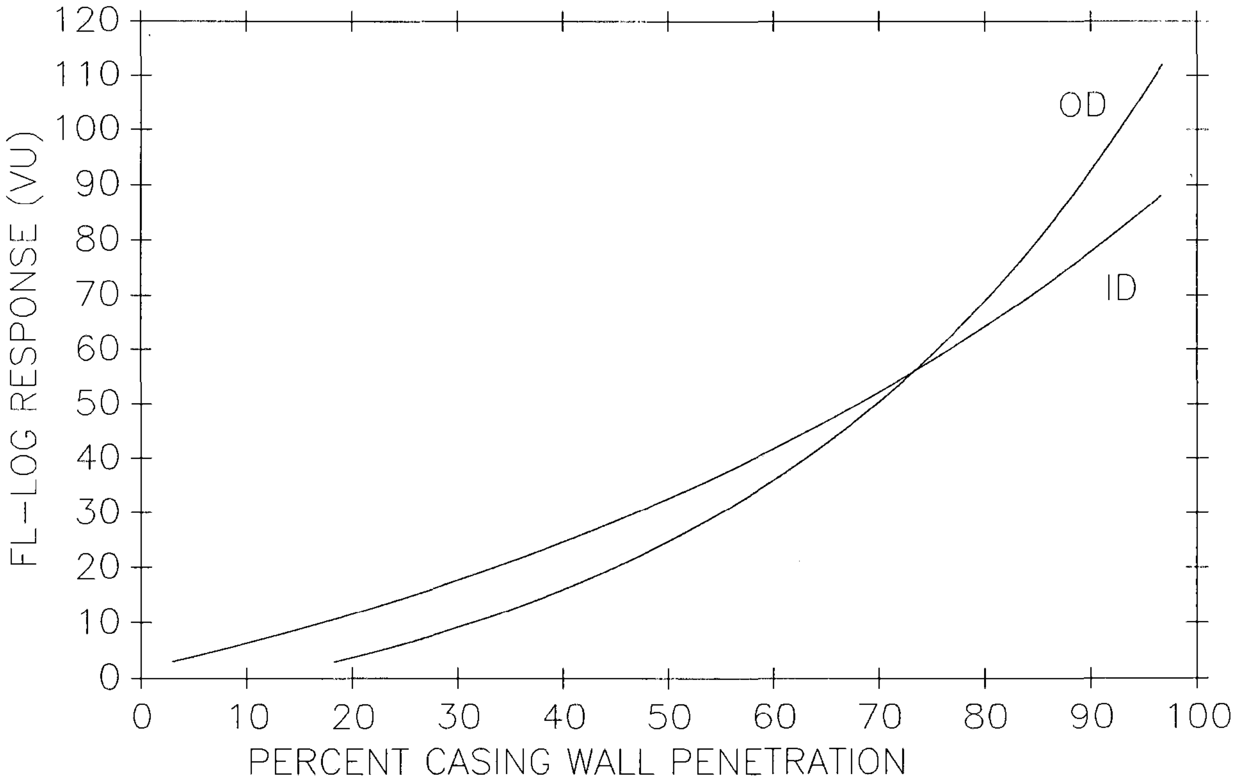

Fig. 12—Vertilog interpretation curves.

Ex. II - 4

VERTILOG®

Western Atlas International
A Litton/Dresser Company

CUSTOMER	SOUTHERN CALIFORNIA GAS COMPANY	WORK ORDER NO.	124303	DATE	12-16-88
LEASE/WELL NO.	STANDARD SESNON No. 9	CUSTOMER ORDER NO.			
FIELD	ALISO CANYON	COUNTY	LOS ANGELES	STATE	CALIFORNIA
CASING O.D.	7" WEIGHT(S) 23,26,29	NOMINAL WALL THICKNESS		GRADE	J-55,N-80
TOTAL FOOTAGE INSPECTED	8553'	FROM	SURFACE	TO	8553' DEPTH

SUBSURFACE CASING DEFECT REPORT

LENGTH NO.	TYPE DEFECT	PENETRATION	LENGTH NO.	TYPE DEFECT	PENETRATION
OUTSIDE 13-3/8" SURFACE CASING					
51	OD IP	21 - 40			
62	OD IP	21 - 40			
64	OD IP	21 - 40			
67	ID IP	21 - 40			
85	ID IP	21 - 40			
91	ID IP	21 - 40			

ABBREVIATIONS:

O.D. – OUTSIDE DIAMETER
I.D. – INSIDE DIAMETER
I.S. – INSIDE SURFACE PIPE
T.L. – THROUGHOUT LENGTH
I.P. – ISOLATED PITTING
C.C. – CIRCUMFERENTIAL CORROSION
G.C. - GENERAL CORROSION

WA-1364-C (10/87)

Ex. II - 5

VERTILOG INTERPRETATION

COMPANY: SOUTHERN CALIFORNIA GAS COMPANY
WELL: I.W. 82
FIELD: ALISO CANYON 11·11·89
CNTY: LOS ANGELES
STATE: CALIFORNIA

wall loss

DEPTH	VERTILOG UNIT	LOCATION & EXTENT	CHART NO. 86J55E	CHART NO. 86P1E	PERCENT AVE
74	20	ID or OD, IP	60 or 52		60 or 52
2148	15	ID, IP	34		34
2166	14	OD, IP	39		39
2251	21	OD, IP	48		48
3962	8	OD or ID, IP	30 or 19		30 or 19
4136	8	OD, IP	30		30
4841	8	OD, IP	30		30
6180	9	OD, IP	31	24	27.5
6682	34	OD, IP	60	53	56.5
6786	10	OD, IP	33	26	29.5
6825	12	OD, IP	36	29	32.5
6867	18	OD, IP or GC	44 or 32	37 or 25	40.5 or 28.5
6891	12	ID, IP	28	15	21.5
6960	8	OD, IP	30	23	26.5
6971	12	OD, IP	36	29	32.5
6976	10	ID, GC	15	6	10.5
7034	10	OD, IP	33	26	29.5
7051	10	OD, IP	33	26	29.5
7078	76	ID, IP	94	87	90.5
7088	64	ID, IP	86	75	80.5
7112	122	ID, GC	83+	72	77.5
7123	16	OD or ID, IP	42 or 36	35 or 20	38.5 or 28
7150	40	ID, GC	42	25	33.5

Ex. II - 6

87-DT-102

Multi-Channel Casing Inspection Instrument

STEPHAN A. MATO, JR., Senior Research Engineer, Atlas Oilfield Services
Western Atlas International, Inc.

ABSTRACT

The present state of the art in casing corrosion analysis is represented by the Vertilog survey. This tool provides accurate information regarding the extent and depth of anomalies in casing in a well. Advances in instrumentation have been made that can increase the ability to define and interpret anomalous responses in this type of downhole measurement. Studies have been performed relative to these advances. An experimental tool that incorporates these advances into its design has been built and commercially run. Independent research by Southwest Research Institute, in studies sponsored by the A.G.A. (PRC Projects PR-15-411 and PR-15-614), has also demonstrated these advances and further demonstrated the "next generation" of technology needed to exploit more fully these advances in defining the complete condition of the casing in a well.

INTRODUCTION

The Atlas Oilfield Services Vertilog® casing inspection tool is designed to evaluate the condition of casing in place in a well. Data that are provided by the tool are used to determine the depth and extent of corrosion or other defects, natural or man-made, in the casing. The tool responds to isolated pitting and general casing body wall losses over small areas. Furthermore, the tool will also respond to completion equipment (centralizers, scratchers, etc.) that are placed within the well; however, it does not respond to gradual changes in the casing body wall, as in drill string wear.

HARDWARE DESCRIPTION

The mechanical assembly (Figure 1) consists of an iron core (A), pole pieces (B), and a sensor assembly (C). The core is made of a soft iron material wound with several layers of wire. A DC current is passed through the wire to generate a large DC magnetic field. The specially designed pole pieces are used to improve the coupling of the magnetic field to the casing. Sensors are placed around the core in two parallel rings (Figure 1-C, upper and lower shoe ring) so that the coverage by one sensor overlaps the coverage of another sensor. This sensor arrangement assures that the entire casing wall is inspected. The sensors are contained in "shoes" that are spring loaded to maintain contact with the casing wall. Two sets of sensors are contained in each shoe, which provide flux leakage or FL and eddy current or EC data (Figure 2). The FL sensors are oriented with

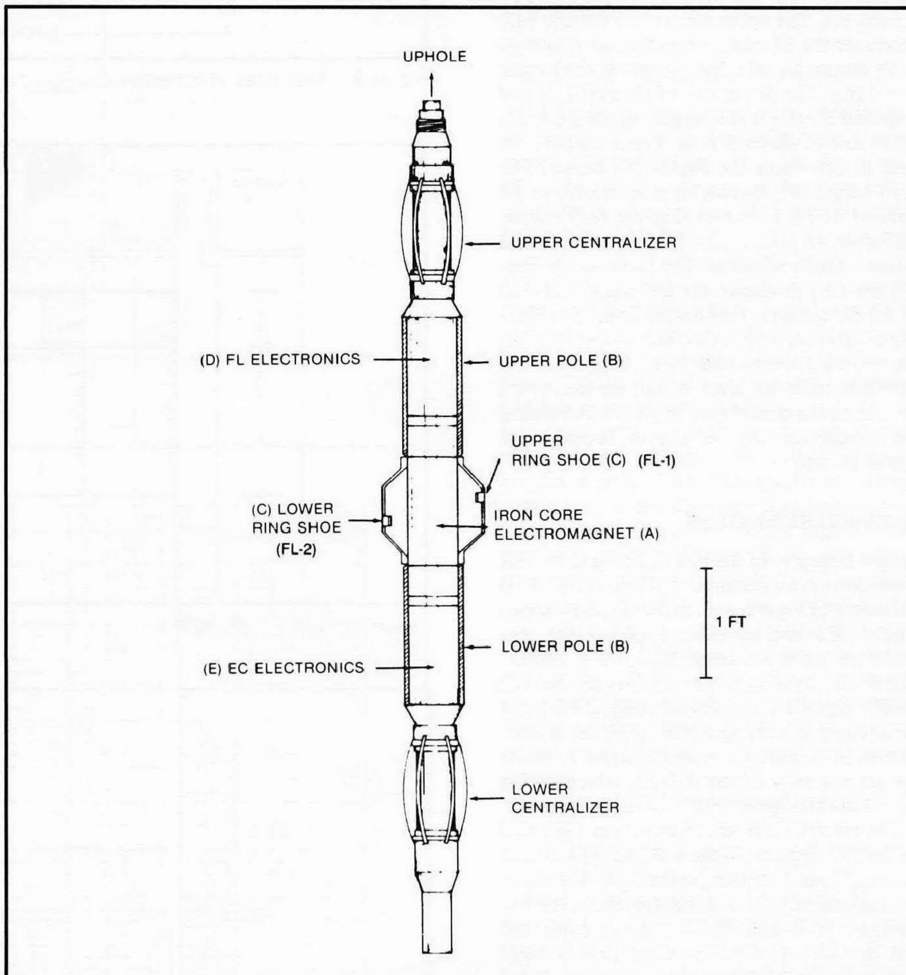

Figure 1. Vertilog mechanical assembly.

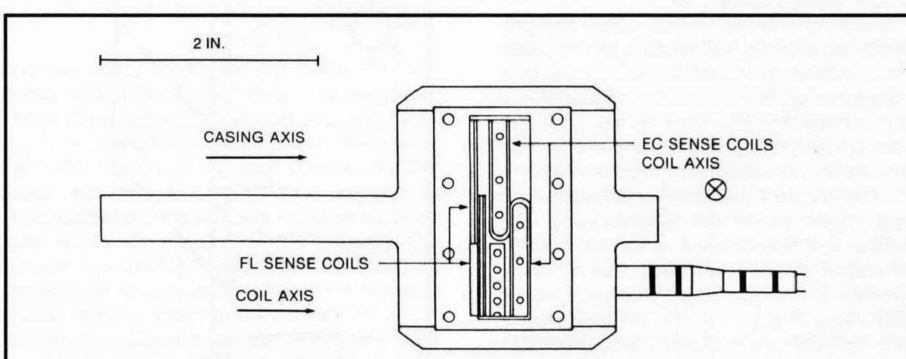

Figure 2. Vertilog shoe.

their axis parallel to the casing axis and used to determine the depth and extent of defects. The EC sensors are oriented with their axis perpendicular to the casing axis and used to determine whether the defects are external or internal. Figure 3 shows a typical joint of casing under the influence of the magnetic field generated by the core. Note the lines of flux that leave the casing at the defect sites. These magnetic field lines are detected by the FL coils and then processed by the subsurface electronics.

Two electronic packages are enclosed in the pole pieces (Figure 1-D and 1-E) to process and transmit the four different signals produced by the sensors. The upper electronics (Figure 1-D) processes the FL sensor signals and generates three output signals. One output is the largest signal from the upper row of shoes (FL-1) and a second output is the largest signal from the lower row of shoes (FL-2). These outputs are used to determine the depth of a defect. The third output (FL-Average) is proportional to the number of FL-1 sensors that are responding. This gives an indication of the circumferential extent of the corrosion. The lower electronics (Figure 1-E) processes the EC signal from all of the EC sensors. This output is used to identify an internal defect. All four of these signals are sent up a seven-conductor wireline cable to a surface recorder. Each of the signals is sent up a separate conductor, while the remaining three conductors are used to provide power and signal ground.

DATA PRESENTATION

Typical examples of the tool response to various conditions in an example well (see Figure 5-A) are shown in Figures 4, 6, and 7. Figure 4 shows typical collar and corrosion response. Note that at the collars, the Average, FL-1, FL-2, and EC signals all have a large amplitude response. The smaller signal amplitude and unequal FL-1 and FL-2 responses correspond to corrosion defects. Also note the absence of an EC signal response for the majority of the defects, which in this case indicates primarily external corrosion. There are several internal defects as indicated by the EC signals. Figure 6 shows typical centralizer, scratcher, and perforation responses. For the centralizers and the scratchers, the FL-Average, FL-1, and FL-2 signals respond, but not the EC. The perforations have a large amplitude signal response on FL-1, FL-2 and EC but only a small response on the Average. Figure 7 shows a response to the end of the surface casing (casing shoe).

It should be noted that the above interpretations are aided by well records. If a response that is similar to a scratcher occurs where it is not expected, it may not be recognized as a scratcher and therefore would be interpreted as a defect. Such interpretations occur primarily when the well records are incomplete or inaccurate. One frequent inaccuracy is the determined depth of the end of the surface casing. The Vertilog tool will respond to the presence of the end of the surface casing (casing shoe), especially if the outer string is offset from the inner string (Figure 5-B). Large signal deflections indicate severe defects, but, when the depth of the end of the surface casing is not known, it cannot be determined if the surface casing shoe is responsible for the observed

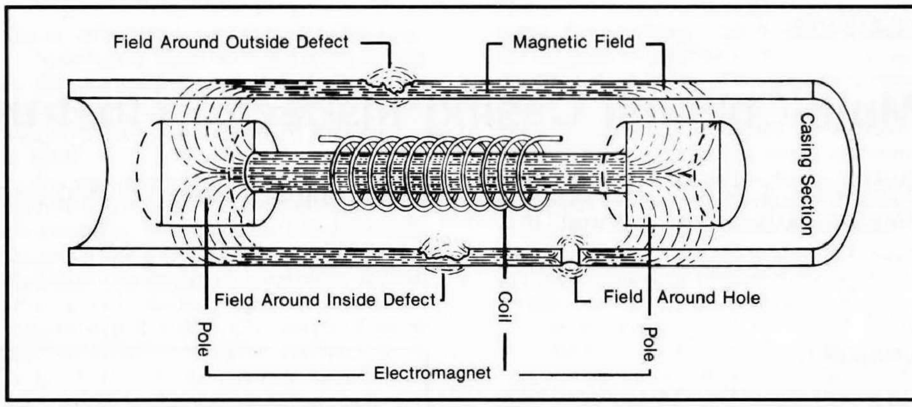

Figure 3. Flux lines in defective casing.

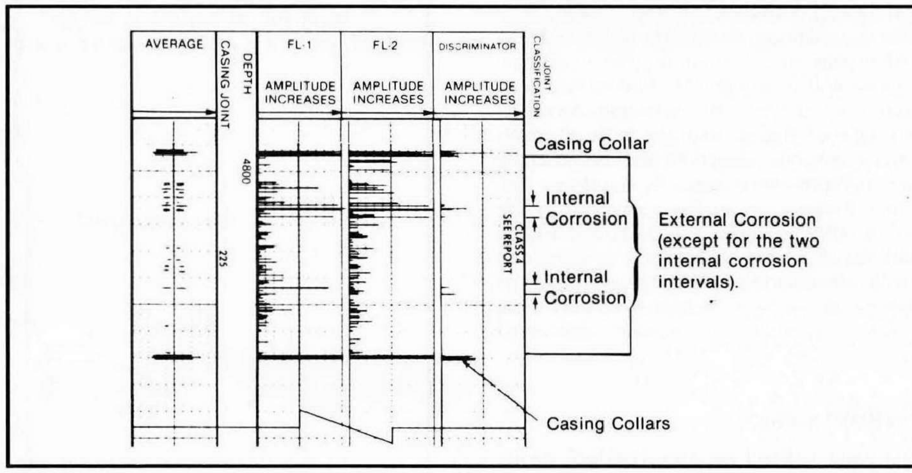

Figure 4. Vertilog examples.

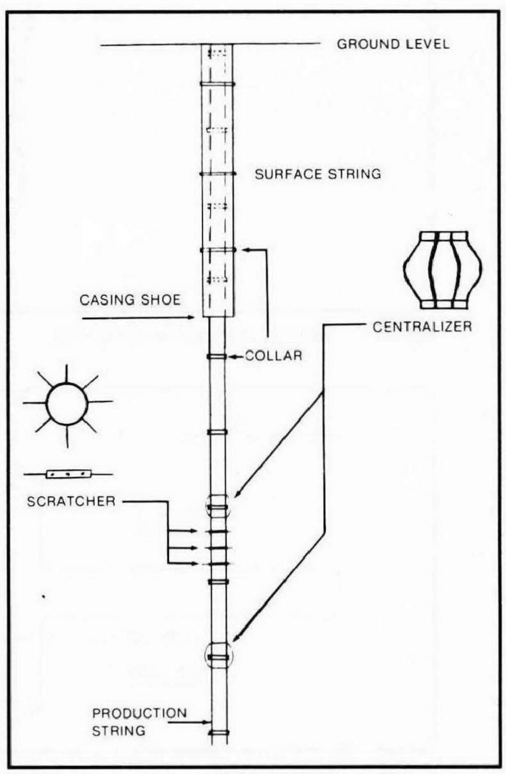

Figure 5A. Typical well.

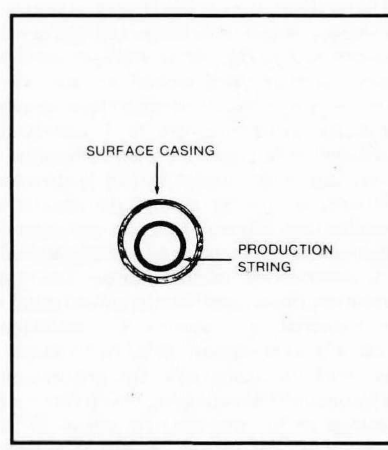

Figure 5B. Offset casing.

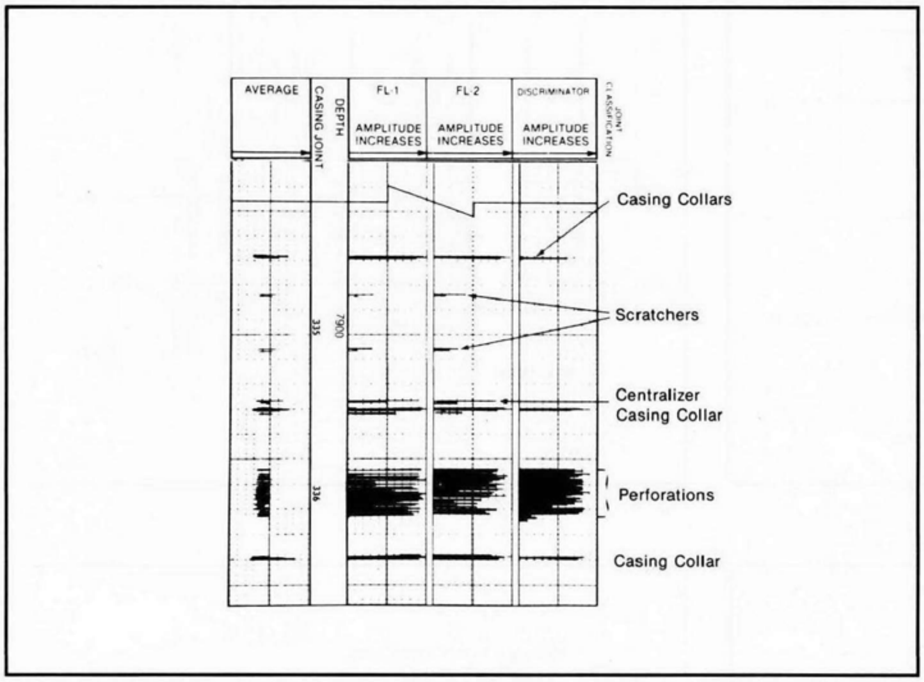

Figure 6. Vertilog examples.

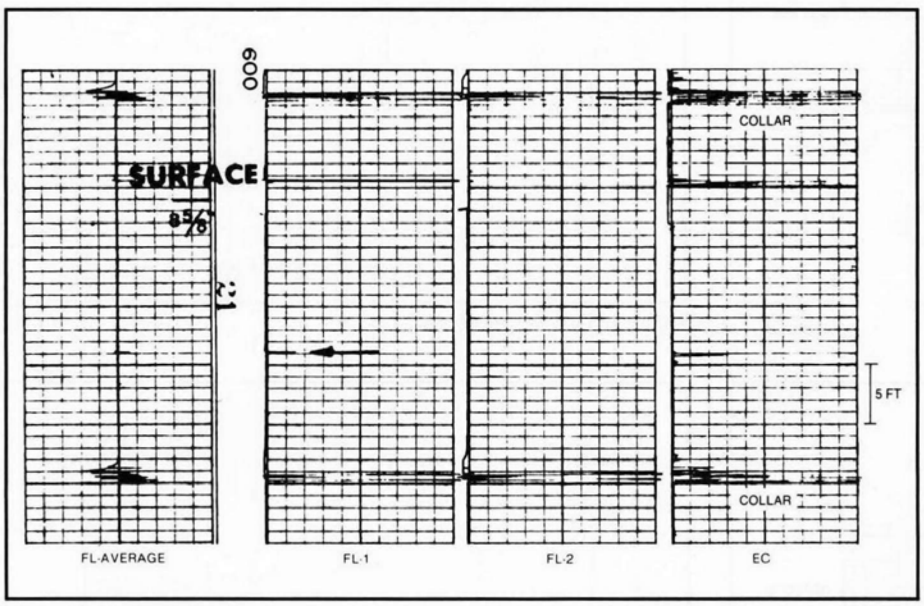

Figure 7. Surface casing response.

response. It must therefore be assumed that the response is due to corrosion. Figures 8, 9, 10, and 11 show examples of typical surface casing shoe responses.

EXPERIMENTAL TOOL

In an effort to improve the identification of anomalous responses from the Vertilog tool, a decision was made to re-examine the information obtained from the tool. The standard mechanical assembly was used in combination with an experimental electronics package. The output from a single sensor, without any signal processing other than amplification and noise reduction, was examined initially. Lab tests were run on casing having defects milled into the body wall of the casing. These defects ranged from 10 percent penetration of the casing wall up to 90 percent penetration of the casing wall. A ¾-inch ball mill was used to make the defects. An example of the sensor response to these milled defects is shown in Figure 12. Note that unlike the standard Vertilog signals, the sensor signal is bipolar. Of immediate interest was the correlation of the width of the response to the physical width of the defect. The initial evaluation of the data implied that there existed a relationship between the defect width and the sensor response width (Figure 13), but further analysis is required in order to clarify the exact nature of the relationship. An examination of the signals from the end of a surface casing was performed next. Tests using only one shoe as before, yielded some very interesting results (Figure 14). As can be seen, the amplitude and form of the surface casing shoe signal is different from the defect signals. It was then decided to transmit the signals from all of the sensors in the 5½-inch tool. The signals were electronically mixed and transmitted to the surface by wireline. At the surface, the signals were separated, and sent to a 12-channel analog recorder. Pitting in the casing was studied first. Later, the response to the surface casing shoe was examined.

FIELD TEST RESULTS

After having logged several wells, certain characteristics of the sensor waveform became apparent. The main observation was that a signal caused by added mass is opposite to that caused by a loss of mass (a fact that was confirmed in the lab). This brings about a unique interpretation method of signals seen by the sensors. A basic sensor response for most casing conditions can be predetermined by knowing its geometry, e.g., a pit (Figure 15). The sensors respond to changes in the magnetic flux leakage field. If the body wall of the casing is constant (A), the sensors would not be expected to generate any signal. When the sensors pass the first edge of the pit (B), the body wall of the casing is reduced (mass loss). This results in a change in the level of the magnetic flux leakage field at the sensor. The sensor output signal is proportional to this change. When the sensor passes the trailing edge of the pit (C), the wall increases (mass gain), causing another change, opposite to the first change. Once the sensor passes the pit, it is again in casing with a constant body wall (D), hence no signal is expected. A sensor output would be expected to appear similar to that shown in Figure 15, and the actual sensor response to a pit is shown in Figure 16.

As the tool approaches a collar (Figure 17), the body wall suddenly increases (A) (mass gain). This causes a decrease of the magnetic field at the sensor and, hence, the sensor generates a signal proportional to the thickness of the collar. Further into the collar, we approach the end of the lower casing joint (B). At this point, it appears to the tool as if the wall is reduced in thickness (mass loss), causing the sensor to generate a signal opposite in amplitude to the first response at the collar. A short distance later, the sensor enters the upper casing joint (C). Since it now appears to the tool that the wall is increased in thickness, the change in the magnetic field causes a corresponding change in the sensor output signal. This signal is the same polarity as the signal received upon entering the collar. Finally, as the tool leaves the collar (D), the body wall of the casing becomes thinner and thus generates a signal proportional to the mass lost. This signal is opposite in polarity to the signal generated as the tool entered the casing. The final output of the sensor will then be like that shown in Figure 17. As can be seen from Figure 18, the actual sensor signal is very similar to the predetermined sensor signal shown in Figure 17.

Other well-completion equipment is detected equally well. Since both scratchers and

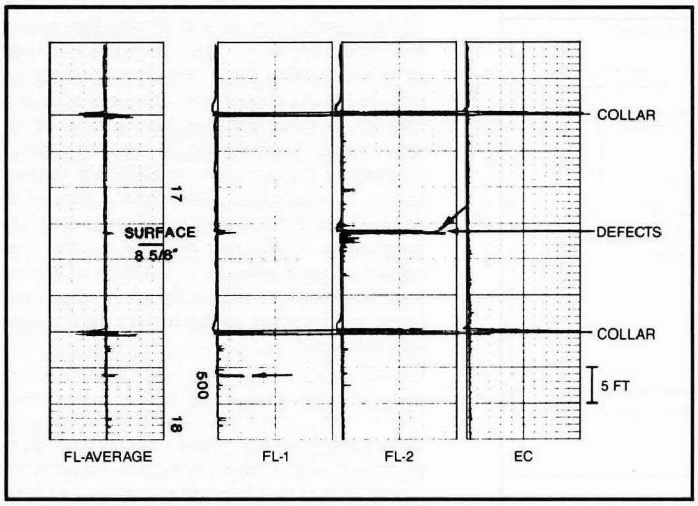

Figure 8. Surface casing response.

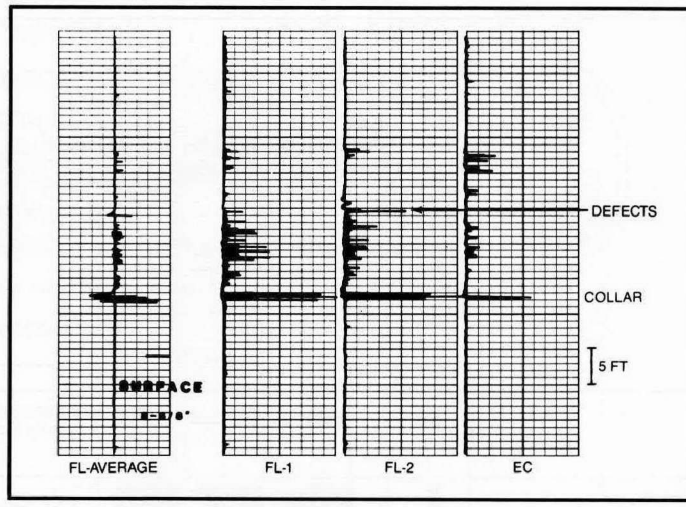

Figure 11. Surface casing response.

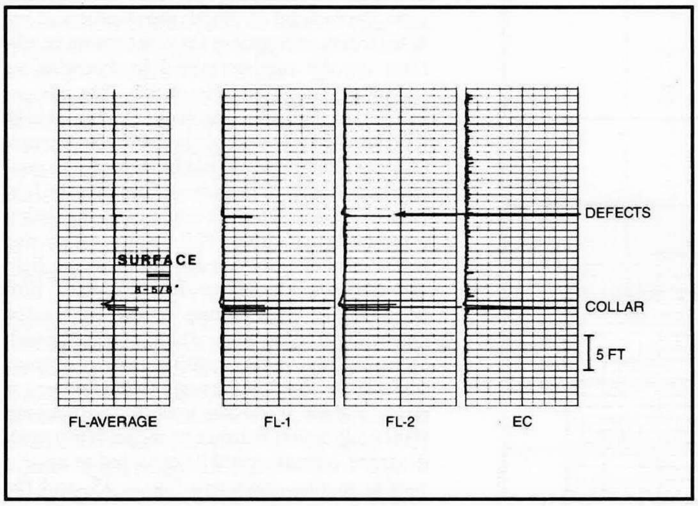

Figure 9. Surface casing response.

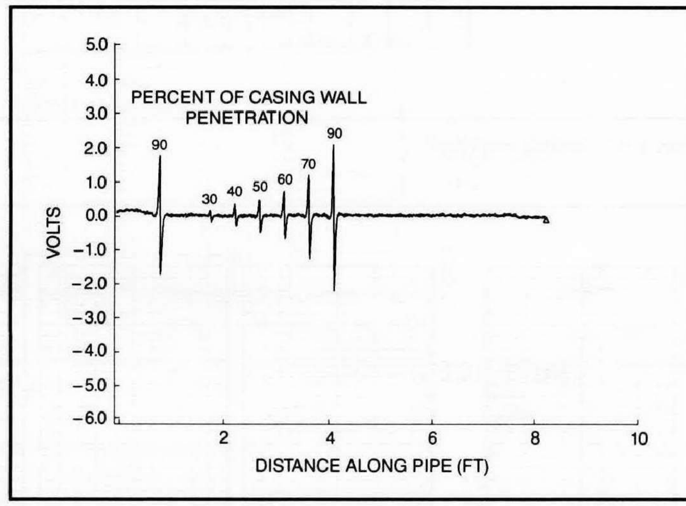

Figure 12. Defect response.

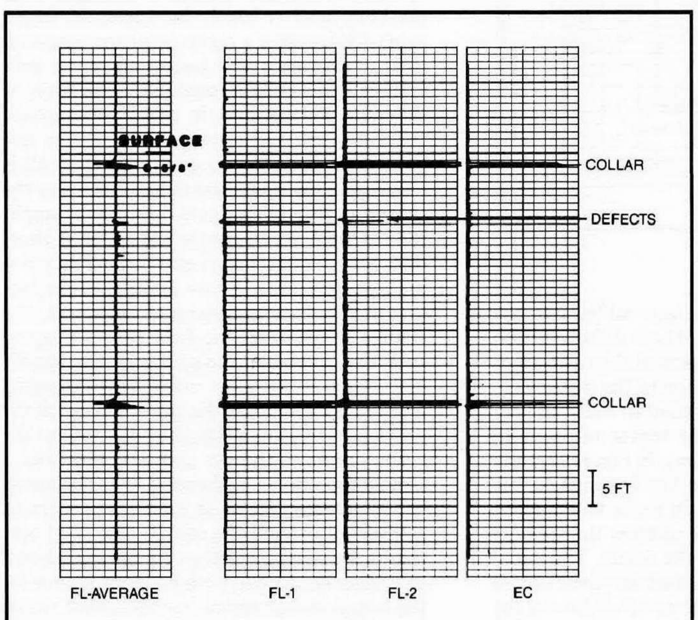

Figure 10. Surface casing response.

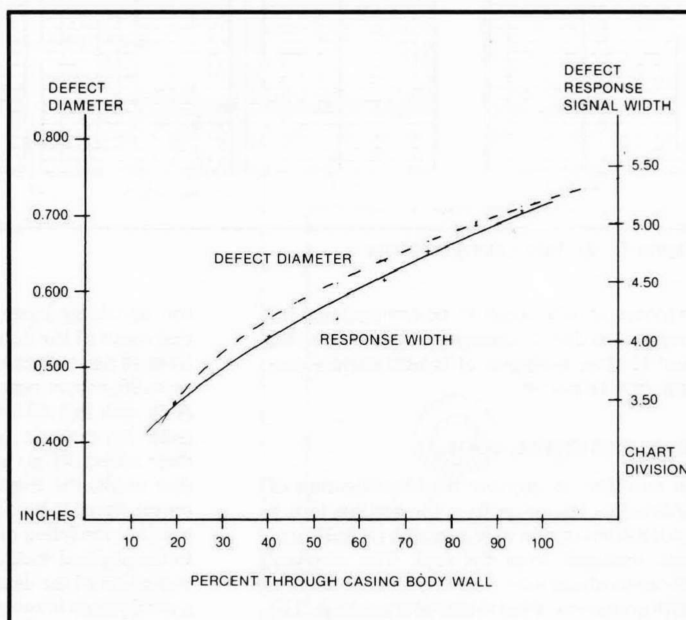

Figure 13. Defect diameter vs. response width.

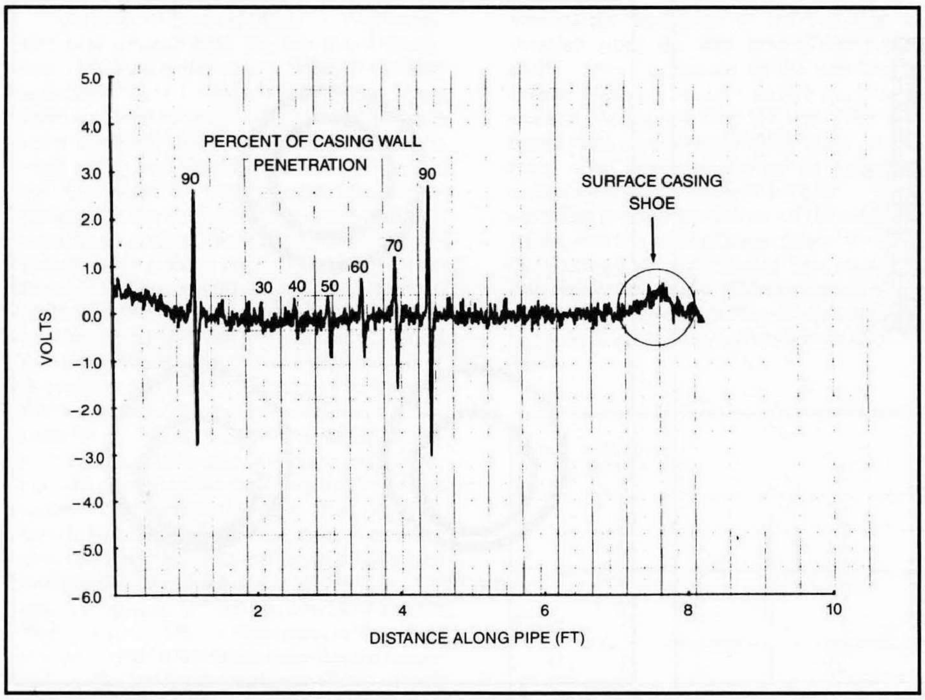

Figure 14. Defects and surface casing response.

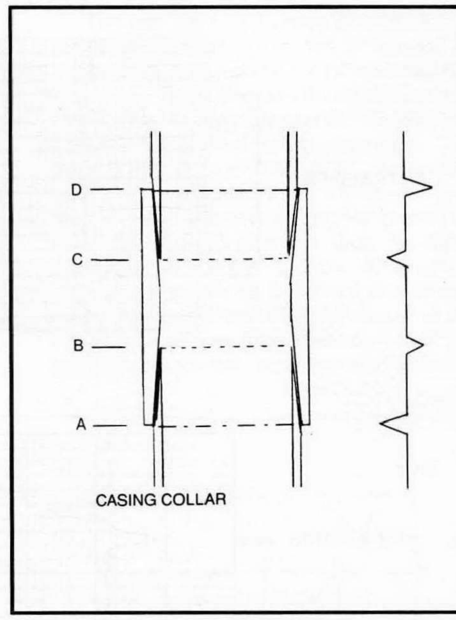

Figure 17. Theoretical casing collar response.

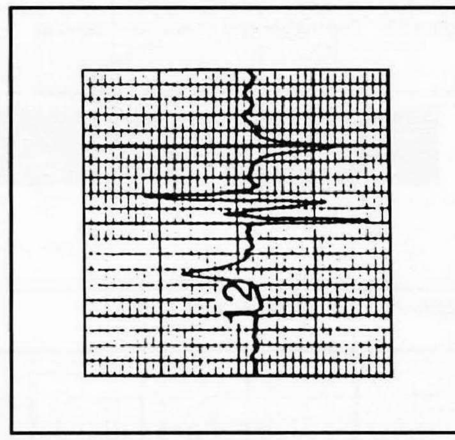

Figure 18. Collar response.

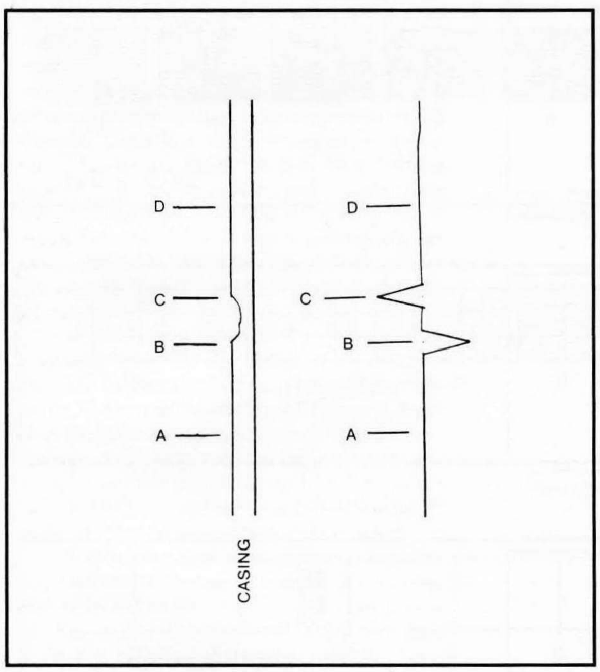

Figure 15. Theoretical isolated pit response.

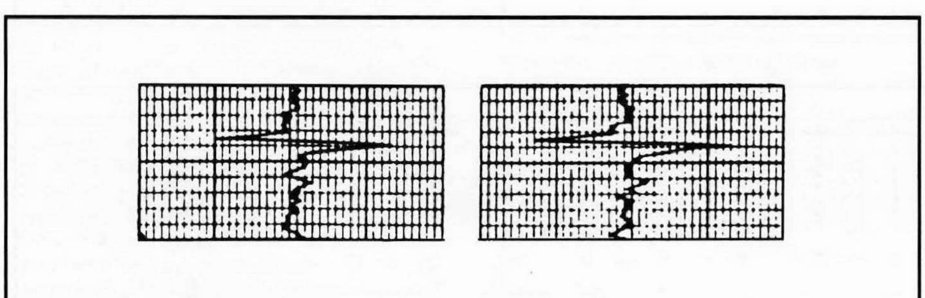

Figure 16. Isolated pit.

centralizers are placed on the outside of the casing, they, in effect, increase the casing wall at the point that they are attached. They should then appear on the log as a mass gain event (Figure 19). Other completion equipment will appear in a similar way and, if the geometry is known, its characteristic signal should be predictable.

As the tool approaches the second string of casing, the effective wall thickness suddenly appears to increase. If the two strings were concentric, a signal similar in polarity to that of entering the collar would be expected on all channels, only smaller in amplitude. However, since there is not a corresponding "thinning" of the wall, only one signal would be expected. Since the casings are rarely concentric, the possible geometries are centralized, offset, and contact (Figure 20). An example of each of these geometries is shown in Figures 21 to 24. Figure 21 shows the centralized condition, Figure 22 shows the offset condition when the two casings are near to being centralized, Figure 23 shows the offset condition when the two casings are close to contact, and Figure 24 shows contact.

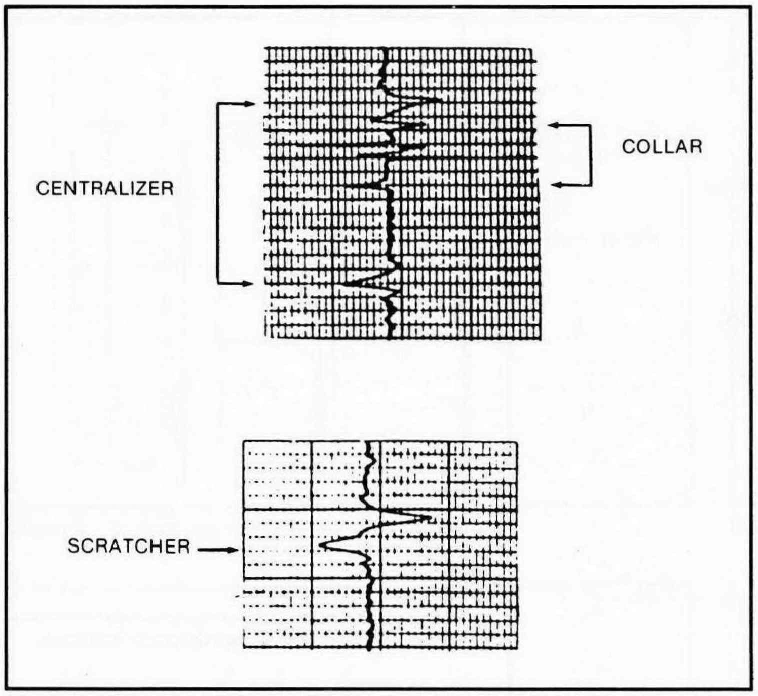

Figure 19. Centralizer and scratcher response.

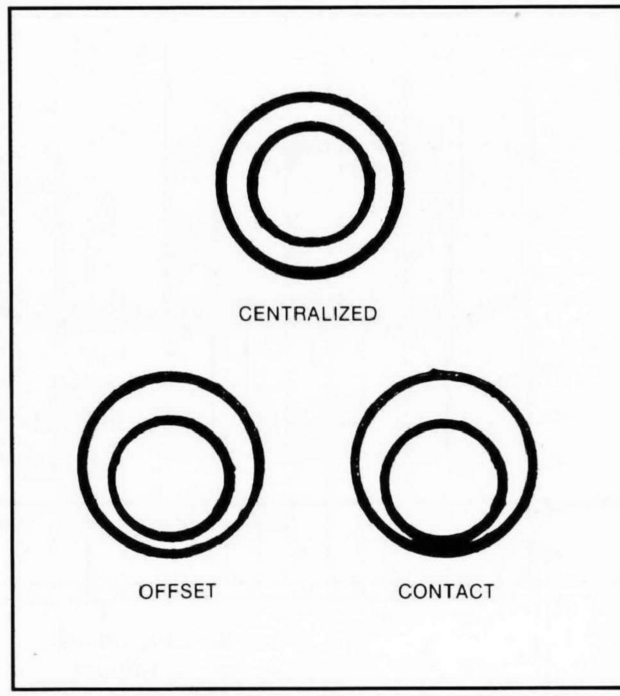

Figure 20. Surface casing geometrics.

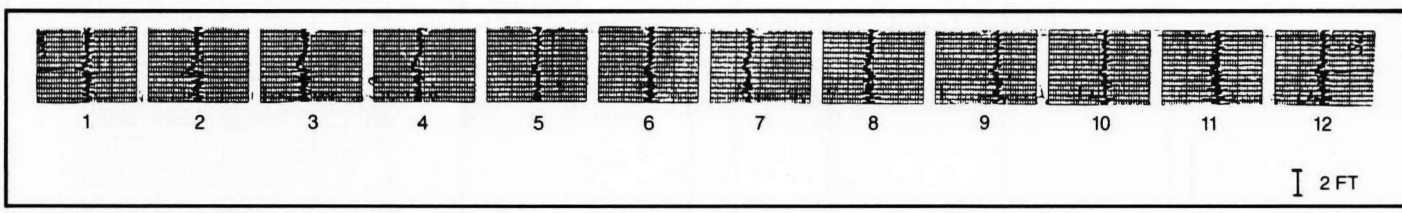

Figure 21. Centralized surface casing.

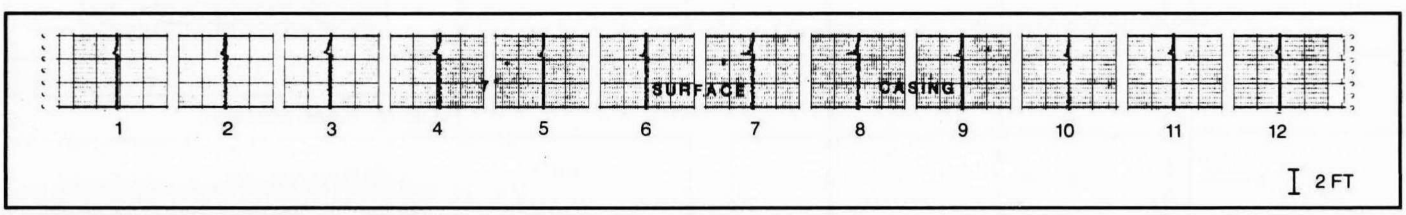

Figure 22. Offset surface casing.

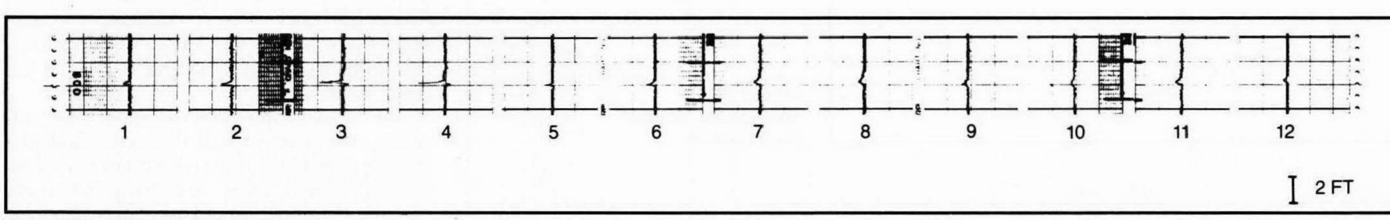

Figure 23. Offset surface casing.

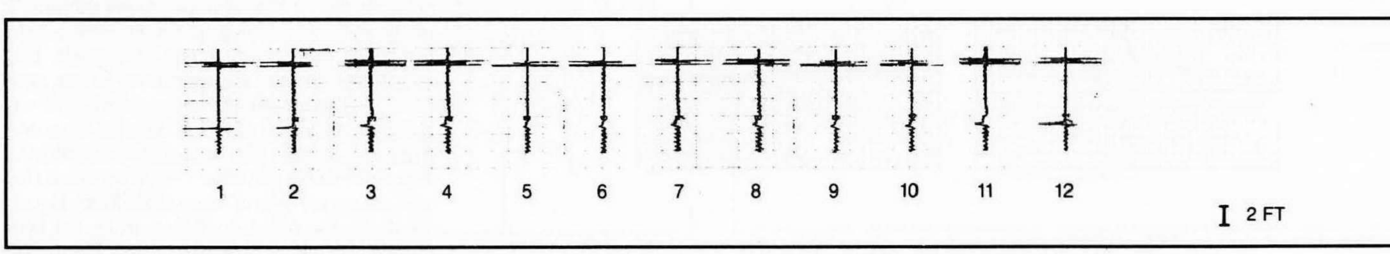

Figure 24. Contact surface casing.

The ultimate purpose of the Vertilog inspection is to identify both the depth and the extent of defects in the casing. When the pitting is isolated, this is a relatively simple task. When there is general corrosion, the situation becomes more complex. The extent of the corrosion is readily discerned from the response of the sensor. One must be more careful when interpreting the depth in general corrosion since a significant portion of the body wall may be missing. This causes a larger signal output from the sensor than would be expected from an isolated defect of a similar size and depth. It becomes more difficult to interpret corrosion that is underneath or just inside the casing shoe. A complex magnetic field pattern occurs with the casing shoe response generally much larger than for pitting. The closer the surface string is to touching the inner string, the more difficult the interpretation becomes. If the pitting is directly underneath the casing shoe, the situation is somewhat simplified, since the casing shoe enhances the effect of the corrosion signal and produces a much larger response than normal. The sensor that sets the corrosion detects both a mass loss and a mass gain, so the signal is bipolar. The ratio of the gained mass amplitude to the lost mass amplitude yields an estimate of the depth of penetration of the pitting. If the pitting is just inside (two inches or less) the surface casing, the signal is attenuated and the corrosion appears to be less than it is in reality. As the pitting gets further into the surface string, the response returns to the expected values for two strings of casing. Figure 25 shows a typical interpretation curve for external (OD) defects. There is a single string curve and a curve for casing inside of 10¾-inch surface pipe. A ratio curve is also used to determine the depth of corrosion that is directly underneath the casing shoe. There is another similar set of curves for internal (ID) defects. There are a series of curves for each weight and grade of casing.

Figures 7, 8, 9, 10, and 11 can now be re-evaluated by use of the 12-channel format instead of the standard data format. Figure 26 is the 12-channel equivalent of Figure 7. Note that the surface casing response appears centralized. Secondly, note the large pit approximately one foot below the end of the surface casing. In this case, there is a defect. Figure 27 is the 12-channel equivalent of Figure 8. Once again, note that the surface casing response appears centralized and that there is pitting, although not as severe as the defect in Figure 26. Figure 28 is the 12-channel form of Figure 9. In this instance, the casing appears offset. Notice the pit response just inside the surface casing where the inner string is closest to the surface casing. This corrosion is not severe. Figure 24 is the 12-channel form of Figure 10. Figure 24 was the example of contact, therefore the Vertilog response is due to the presence of the surface casing. If there is corrosion directly under the shoe, then another interpretation curve similar to the curve presented in Figure 25 indicates it is less than 35 percent of the casing wall. Finally, Figure 29 is the 12-channel form of Figure 11. Note that the casing shoe is 20 feet above the point indicated by the casing records. This changes the interpretation of all of the corrosion, since it is now located outside of the surface casing. With the standard system, the sensitivity of the recorder was doubled when the tool entered the surface casing. Severe corrosion on the standard log format becomes minor corrosion on the 12-channel log format after the sensitivity is reduced to its proper single string value. In summary, what began as five casing joints with severe corrosion have now become only one joint that has a severe defect. Of the other four joints, one has a significant defect that needs monitoring and the remaining three joints have only minor corrosion. This represents a considerable cost savings to the well operator. Only one well requires remedial work instead of five wells.

The one piece of missing information is determining whether a defect is internal or external. Up to this point, the EC coils had not been used on the 12-channel tool. Electronics have been added to utilize the EC sensors. Two signals are produced by the electronics. One signal is from the upper ring of EC sensors and one signal is from the lower EC sensor ring. We can now formulate a complete picture of the casing. The FL channels show the depth and shape of a defect and the EC channels determine if the defect is internal or external. Figure 30 shows a "multichannel" format of the sensor information. This is best used to determine the nature (pit, scratcher, perforations,

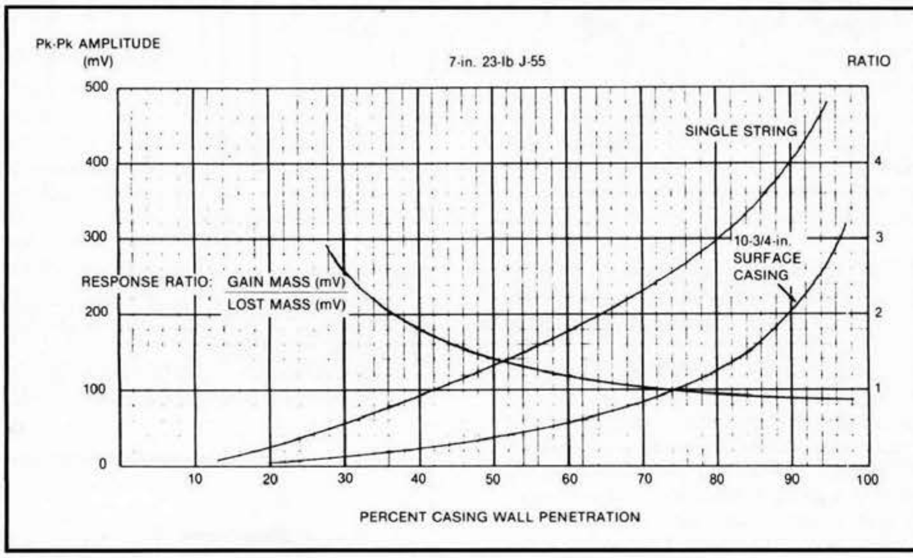

Figure 25. O.D. interpretation curves.

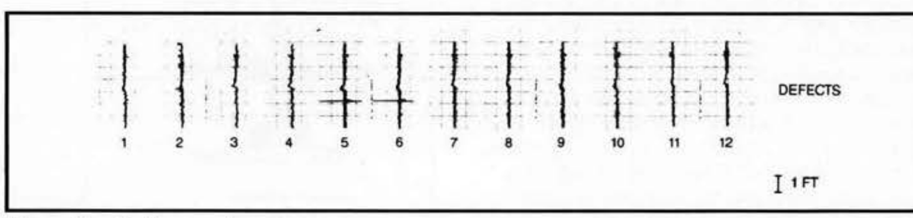

Figure 26. Surface casing response.

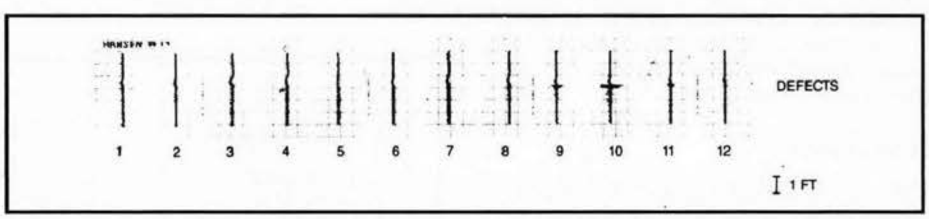

Figure 27. Surface casing response.

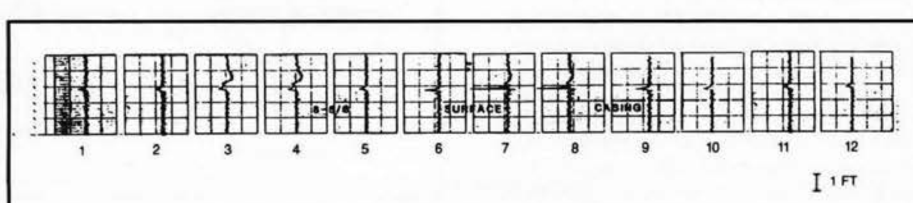

Figure 28. Surface casing response.

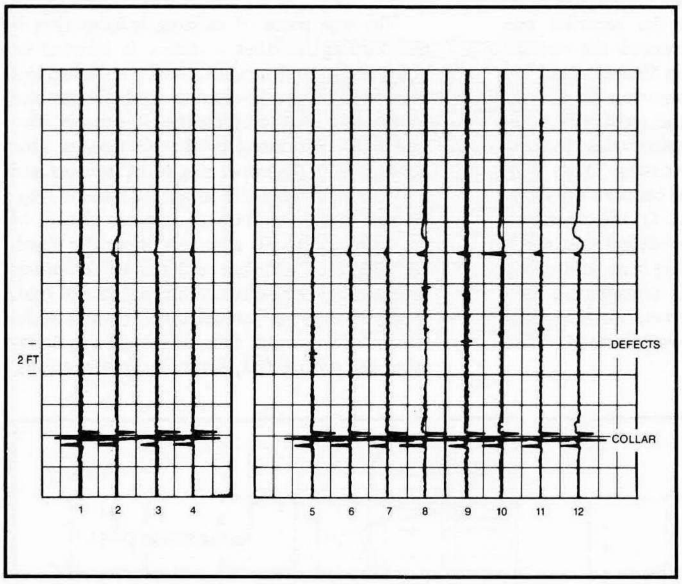

Figure 29. Surface casing response.

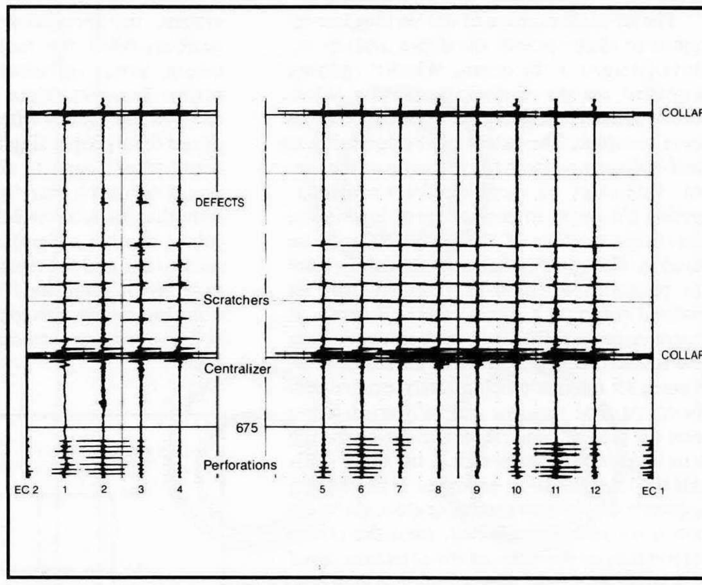

Figure 30. Multi-channel Vertilog.

etc.) and the extent (how wide, how long) of a sensor response. This format does not, however, provide adequate resolution to determine the depths of defects.

A presentation in which defect depths can be interpreted is shown in Figure 31. This format is called the "generated" presentation and is computer-derived from the multichannel presentation. The largest FL and the largest EC signal at a given depth in the well are scaled up and displayed for depth interpretation. In addition, another curve, FL-Average, is derived from the total number of FL channels that are responding at any given instant to give an indication of the circumferential extent of the anomaly. This "generated" presentation is the same format that was originally used with the standard Vertilog presentation. Figure 32 is an example of the standard Vertilog run over the same section of well as previously shown in Figures 30 and 31. Note the similarity in Figures 32 and 31. Also notice how well the perforations, scratchers and centralizers are shown on the multichannel presentation (Figure 30). Comparing the same depth intervals on Figures 30, 31 and 32, the multichannel presentation enhances the interpretation of tool responses to conditions in the well. This type of log presentation and interpretation is unique to the Multichannel Vertilog system.

CONCLUSION

The ability of the experimental Multichannel Vertilog to transmit the entire signal as seen by the sensor coils provides an opportunity to understand better the condition of casing in a well. Corrosion is readily differentiated from completion equipment like scratchers and centralizers. The exact depth of the surface casing shoe can be determined. Collars can be studied; the physical size of the collar and the location of the ends of the two joints of casing that are joined by the collar can be examined. Detailed analysis of the sensor signal itself (signal width, rise time, area, etc.) provides more information regarding the physical parameters of the anomaly. These types of studies, which can be done in a well, have previously been unavailable to industry.

It has been demonstrated that analyzing the entire sensor signal enhances the ability to interpret anomalous responses in a well. Using the experience gained from designing and building the experimental Multichannel Vertilog, an instrument is being designed to transmit information from all of the FL sensors and from all of the EC sensors.

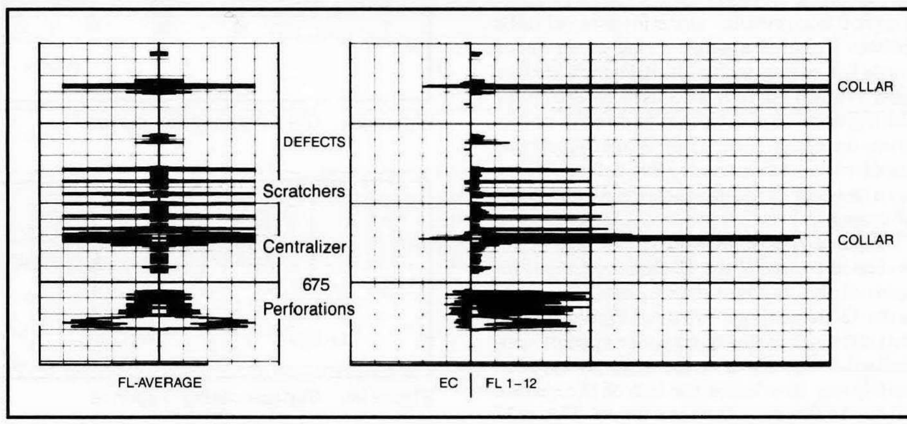

Figure 31. Generated Vertilog.

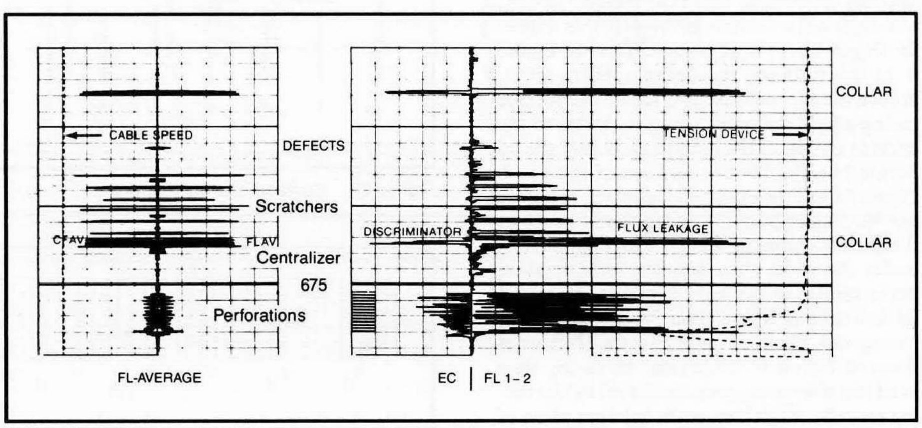

Figure 32. Standard Vertilog.

SoCalGas-7.0044

Ex. II - 7

SPE 81442

North Kuwait Down-hole Corrosion Management Challenge and the Use of New Corrosion Detection Tools to Define the Extent of the Problem

Moudi Fahad Al-Ajmi, SPE, Kuwait Oil Company; Juma K. Attid, SPE, BP; Alex Daye, Baker Atlas

This paper was prepared for presentation at the SPE 13th Middle East Oil Show & Conference held in Bahrain 5-8 April 2003.

Abstract

The North Kuwait (NK) Development Plan calls for rapid increase in NK production, mainly through the implementation of waterflooding in NK major reservoirs. The new production profile incorporates increased water production and, based on corrosion prediction models, results in elevated corrosion rates in down-hole completion equipment. This predicted increased corrosion has already become a reality in the past three years. Severe down-hole corrosion in production and injection wells has resulted in tubing and casing failures and severe casing/tubing corrosions. Remediation of these wells has resulted in problematic, high cost workovers, and in one case, the loss of the productive interval and the associated reserves.

To manage current and future corrosion in NK, an extensive corrosion-monitoring program has been implemented to initially identify the extent of corrosion in the current well stock and then to adopt corrosion prevention strategies to mitigate the problem and reduce the associated cost and production impact. The down-hole internal corrosion monitoring effort is one of the first steps in implementing the NK Corrosion Management Plan.

This paper discusses the results of the program to date and describes the diagnostic tools used to effectively monitor the extent of down-hole corrosion in North Kuwait. Different tools such as the caliper, MicroVertiLog tool (MVRT), and surface inspection methods have been utilized to quantify down-hole corrosion. The paper also compares MVRT tool response with caliper and surface inspection data in an effort to ensure down-hole corrosion detection corresponds with results measured at surface. This will allow immediate corrective action to be taken for the completions based on down-hole log results.

Introduction

First commercial oil production from North Kuwait started back in 1955. According to the Kuwait Oil Company (KOC) production database, production of crude oil with watercut in North Kuwait started in the mid 1980's as water-handling facilities became available. However, the water production was in insignificant quantities.

Down-hole corrosion was not a major issue up to late 1990's due to low or no watercut in most of the wells. In addition, the corrosion problem was indirectly managed through the process of converting wet producers to dry production by applying down-hole water shut-off techniques. The water shut-off (mostly carried out by a rig workover operation) was necessary to allow maximum oil production through the then existing facilities with limited water handling capacity. However, lately, with the increasing water production and water handling capacity in North Kuwait, corrosion has become an important issue. With the implementation of the current development plan, which includes waterflooding of several major reservoirs, down-hole corrosion needs to be managed properly to avoid severe production and operating cost impacts. Corrosion in North Kuwait will impact the whole production and processing stream. This paper, however, only discusses the down-hole tubular corrosion issues.

Causes of Down-hole Corrosion In North Kuwait

Although this issue needs to be fully investigated and confirmed, the cause of current down-hole corrosion in North Kuwait fields is suspected to be mostly the CO_2 in the formation water. The dissolved CO_2 in the formation water is assumed to result in the formation of carbonic acid ($H_2\,CO_3$), which reacts with metal and causes corrosion. The pH of most of the reservoir waters in North Kuwait is acidic (between 5.5-6.5). In addition, the high salinity of the formation water reduces the formation/presence of the protective film on the tubing wall and exposes the tubing to corrosion. We note a strong correlation between cumulative water production and severity of corrosion in most of the wells. This leads to support the hypothesis of CO_2-induced corrosion. With the implementation of seawater injection in Mauddud, Upper Burgan, and Zubair reservoirs, the cause of future corrosion is expected to include other factors as well.

Completion Metallurgy

All the existing tubing and casing in NK are low alloy carbon steel (N-80, L-80 or J-55). Trials of chrome steel tubing have been suggested in the past but have not yet been implemented.

Logging Tools Used

Briefly are described below the main corrosion logging tools that have been used to record down-hole corrosion in NK wells both in tubing and casing strings. The description of the MVRT tool however is extended, as it is currently the main tool being used to monitor tubing strings for corrosion in NK. It is worth mentioning that tubing visual surface inspection has recently been applied in some wells in NK as well. As for liners, no logs to specifically address liner corrosion have been ran in NK.

1. Casing Corrosion Logging Tools Used

Casing corrosion logs are usually recorded during rig workover operations when the tubing string is pulled out. In North Kuwait, casing is routinely pressure tested, and, unless corrosion is suspected, quite often a casing corrosion log is not acquired. The main logging tools used so far are Ultrasonic Casing Imager (UCI), and Pipe Analysis Tool (PAT). Although not widely used in Kuwait yet, Circumferential Acoustic Scanning Tool (Cast-V) provided by Halliburton is an equivalent sonic imaging tool that could be used for casing corrosion monitoring. The Baker Atlas MVRT tool can also be used to inspect casing, but have not been widely used in North Kuwait for casing corrosion monitoring.

UCI (Ultrasonic Casing Imager)

This tool has been marketed by Schlumberger as the UBI tool to provide borehole images, USI to evaluate cement bond and casing corrosion, and UCI to quantitatively measure both internal and external casing corrosion or damage (for casing diameter ranging mostly between 4 ½ to 13 3/8 in). The sonde includes a rotating transducer subassembly. The transducer is both a transmitter and a receiver transmitting an ultrasonic pulse and receiving the reflected pulse.

The tool is making radius and thickness measurements allowing the depth of the anomaly to be quantified. With 180 focused measurement during each revolution of the ultrasonic sensor, and up to five rotations every inch of travel inside the casing, the UCI tool is claimed to have the resolution and sensitivity needed to measure pits and other anomalies down to diameters as small as 0.3 in. on either the inside or outside surface of the casing. The high resolution of the UCI tool is claimed to be due to the high transducer frequency of 2 MHz. The signal is, however, attenuated by the borehole fluid and therefore best results are obtained when brine, oil, or very light mud are used.

Tool Operation: The tool works in the following way: first echo time gives internal radius measurement. The second echo time gives casing thickness. Internal and external surface echo amplitudes give a qualitative visual image of casing condition. Wellsite presentation is corrected for tool decentralization effects.

The UCI logs have been used in several North Kuwait completions to assess the casing conditions and make well intervention decisions. However, in North Kuwait no efforts have been made to verify the UCI results through pulling the damaged casing out and performing surface inspection.

PAT (Pipe Analysis Tool)

This tool used to be marketed by Schlumberger. However, newer tools such as UCI have replaced it.

Tool Operation: The PAT sonde has two sets of arrays. Each array has six pads, and each pad makes two measurements: the first one is an eddy current measurement where a high-frequency signal induces a flux on the inner wall of the casing. The presence of the inner wall corrosion causes a flux distortion that is measured by the tool. The second measurement is the flux leakage measurement where electromagnets generate a flux in the casing. The presence of inner and/or outer wall corrosion generates flux leakage that is measured by the tool. In NK, several casing strings have been surveyed by this tool in the past.

CAST-V (Circumferential Acoustic Scanning Tool)

This tool marketed by Halliburton, is the equivalent of Schlumberger's UCI tool. CAST-V furnishes borehole images (when operated in image mode) and provides casing inspection and cement evaluation capabilities (when operated in cased-hole mode)[1]. It can cover casing diameters ranging between 5 ½ to 13 3/8 in. When ultrasonic CAST-V operates in cased-hole mode, full circumferential maps of casing thickness and acoustic amplitude are generated. These maps are used to reveal thinned casing as well as to distinguish between cement and fluid in the annular space behind casing.

Tool Operation: CAST-V uses two ultrasonic transducers: a primary and a secondary transducer. The primary transducer is mounted in a rotating scanner head and is in direct contact with borehole fluid. The scanner head rotates continuously about the tool axis, transmitting ultrasonic signals and receiving reflections from the casing or formation. The secondary transducer is secured in a fixed position on the scanner assembly and is in direct contact with the borehole fluid.

This tool is fairly new to Kuwait and has not been used to monitor casing corrosion in North Kuwait as much as UCI.

2. Tubing Corrosion Logging Tools Used

Tubing corrosion monitoring tools were not available in Kuwait Prior to 1998. In early 1998 efforts were made to evaluate the extent of corrosion in down-hole tubular. New tools were brought in Kuwait specifically for this purpose: multi-finger calipers, which can detect internal defects only, and MVRT, built to detect both internal and external corrosion.

Multi-finger Caliper

Historically, mechanical calipers have mostly performed inspection of production tubing. Mechanical arms serve to provide a profile of the tubing inner diameter (ID). Experience has shown however, that mechanical calipers have a number of limitations, including the inability to provide 100% coverage or identify external defects of the tubing. Internal deposits may also adversely affect mechanical calipers and their use may cause preferential caliper track corrosion unless the tubing is inhibited after logging. Results from the caliper log might prove difficult to repeat due to incomplete coverage/tool rotation.

Due to these limitations, calipers have not been widely used in NK for down-hole tubing inspection. Caliper was mainly used where there were no concerns about the tubing external corrosion. It was also used to validate MVRT response.

Modified versions of mechanical calipers are available now providing better coverage of the tubing ID and better log presentation.

MVRT (Micro VerRtilog Tool)

MVRT tool marketed by Baker Atlas, applies magnetic flux leakage (FL) technology to determine the location, extent and severity of corrosion and other metal loss defect in carbon steel tubular.

MicroVertilog tools employ a permanent magnet circuit designed to produce high levels of magnetic flux within the tubing or casing body wall. Defects, such as internal or external corrosion pitting, cause flux perturbations (leakage) that are detected by a circumferential array of inductive coil (FL) sensors.

The MicroVertilog tools also employ a circumferential array of discriminator (DIS) sensors, each aligned with a corresponding FL sensor that respond to flux anomalies occurring at the tubing inner surface. The combination of FL and DIS data allow the MicroVertilog to differentiate between internal and external features **(Fig. 1-2)**.

The MicroVertilog system produces digital bipolar waveforms, allowing metal gain anomalies (centralizers, down-hole hardware) versus metal loss (corrosion, mill defects) to be determined from the log signatures **(Fig. 3)**.

The MicroVertilog tools are configured such that the FL sensors are all housed within a smooth cylindrical mandrel with dynamic wheeled centralizers located above and below the mandrel. The DIS sensors are conveyed to the tubing ID via spring loaded shoe assemblies to maintain close proximity to the tubing inner wall during logging.

MVRT Applications: The MVRT tool can be used to:

- Detects internal and external tubular corrosion and quantify extent and depth of penetration.
- Monitor corrosion rates over time through the use of successive logging surveys.
- Determine effectiveness of corrosion inhibition program.
- Identify tubing string make-up and location of collars, pups, mandrels valves and crossovers.
- Determine the appropriate timing and scope of workovers and tubing replacement.

Tool Calibration: Calibration of the MVRT is based on observed correlation between defect size in tubular and the amplitude of a signal produced by measurement of the flux leakage field around such defects. To provide the basis for interpretation each size of tool has to be logged in a controlled situation with a variety of artificial and natural defects.

A series of man made defects is created in tubing/casing samples purchased from a typical oil field supply yard consisting of pit depths ranging from 20% to 90% of the pipe wall thickness. Through holes are also produced. Three different diameters are drilled producing a 6:1, 4:1, and 2:1 width to depth ratio. Defects are produced both internal and external. The tools are pulled through the test tubing in a series of runs. Care is taken to maintain a constant logging speed and adequate sampling. The amplitude of the responses to each type of pit is recorded. The responses are plotted on an x-y chart of amplitude versus percent penetration. Curves are fit through the data points for each group and then as a whole. The result is a general best-fit curve to represent the range of defects available. Each size, weight and grade of pipe that has been characterized has a corresponding chart and best-fit curve to represent the tool response to defects. Calibration charts are available for all weights and grades of pipe.

MVRT Log Data Display: The MVRT log data is displayed on a continuous depth versus senors' response format and includes several data tracks. In addition to raw data, maps of internal and external defects and a joint-by-joint classification of logged tubing string into four classes is presented **(Fig. 4)**. If tubing joint has at one or more points (0 –25)% wall loss, it is classified as class 1, (25-50)% class 2, (50 – 75)% class 3 and (75-100)% is class 4. Obviously class 4 includes holes or 100% wall loss. Here the class is determined by the highest wall loss recorded in the joint. One has to use his/her own assessment of how one class 4 joint compares to another one and therefore, a review of the foot-by-foot data becomes necessary. A summary plot showing wall loss versus depth is usually presented in a condensed format in a single page. This is a useful display to review the overall tubing conditions **(Fig. 5)**.

It is worth noting that the tool resolution is within +/- 10% wall loss. It is claimed that MVRT can quantatively measure defects as small as 0.25 in. diameter with only 25% wall loss.

Data Gathered

As of August 2001, in NK, 85 tubing strings have been logged with calipers and MVRT tools as shown in **Fig. 6**. The ramp up of corrosion surveys in NK in year 2000 was partially due to the recording of baseline corrosion surveys in the injectors of the waterflood reservoirs in NK. The baselines were deemed necessary to assist in time-lapse interpretation and corrosion rate determination.

In addition to tubing monitoring logs, over 16 casing corrosion logs have also been recorded in NK wells since 1994 **(Fig. 7)**. In light of the relatively large number of wells in NK, this number of casing corrosion logs is low. It is recommended to obtain more casing corrosion logs to cover casing and liners particularly in the wells that have produced and or producing wet crude through casing. Liners are exposed to production fluids and subject to corrosion. In some oil fields, to prevent liner corrosion, liners/casings below the production packer are completed with corrosion resistant material.

Out of the 85 tubing corrosion logs recorded in NK, nine MVRT logs were recorded in NK Water Flood Pilot project (WFP) eight producers, as MVRT was repeated in one of the producers[2]. 22 baselines MVRT logs were recorded in NK Sea Water Injection (SWI) project injectors. Two caliper logs were recorded in Effluent Water Disposal wells (EWD). The rest of the tubing down-hole corrosion logs were recorded in NK producers where reservoir pressure is naturally maintained through strong aquifer support. MVRT was also repeated in one of these producers.

Data Analysis

The analysis was done mainly for the tubing strings that have been logged with MVRT. Only a small number of caliper logs were included in the analysis. The reason behind this was that in caliper log display, the tubing wall loss is not classified numerically, while in MVRT data disply, results are displayed in four classes depending on the percentage wall loss of each joint. In addition, a summary chart showing tubing joint wall loss in percent versus depth is presented. This made it easy to use the data. The down-hole corrosion data of the SWI injectors are not included in the analysis. The gathered data was analyzed for the following relationships.

1. Watercut vs. Corrosion Severity

Fig. 8 shows a graph of the stable watercut in the producing string versus tubing wall loss. From the data the following observations can be made:

- There is a general correlation between the stable watercut of the produced fluid from the tubing versus the tubing wall loss. It has been observed that class 3 corrosion (50-75% wall loss) occurs mostly at watercuts above 25%.
- Some of the tubing strings despite having low watercut showed higher corrosion (class 2 to 4) in few joints. However, the reason for this anomaly is believed to be poor quality control of tubing during running completion **(Fig. 9)**. Mixing tubing of different grade and age in a well completion causes down-hole corrosion data interpretation problems and potentially reduces effective life of the completion.
- For the wells that were producing at high watercut but showed relatively lower wall loss (corrosion classes of 1 or 2), the reason was found to be shorter duration of wet production.

2. Depth vs. Corrosion

In about 15 wells a peculiar relationship between depth and corrosion severity was observed. However, it was not a linear depth versus corrosion relationship. The corrosion was observed to start almost abruptly after certain depth. A closer look at these wells revealed that these depths where corrosion abruptly increased correspond to reservoir fluid bubble point pressure in the tubing. It was interpreted that since corrosion in North Kuwait wells in the non-waterflooded reservoirs is mainly due to CO_2 being dissolved in formation water, the bubble point pressure does play a role in changing corrosion pattern in the tubing. Below the bubble point pressure the CO_2 is dissolved in the water, which consequently makes the water more acidic due to the formation of carbonic acid. The acidic water causes more corrosion. Above the bubble point pressure in the tubing, the CO_2 is released and therefore, the water becomes relatively less corrosive **(Fig. 10-11)**.

3. Corrosion Rate Estimate

MVRT was run twice in two tubing strings: WELL-0123 and WELL-0030. **Fig. 12** and **Fig. 13** show depth versus penetration charts for each well with the time lapse logs. In WELL-0123 the time lapse between the two MVRT logs was about seven months. The N-80 3 ½ tubing (which has a tubing wall thickness of about 12.9 mm) shows 31% increase in wall loss/year in one of the corroded intervals. This suggests a corrosion rate of 4 mm/yr in N-80, 3 ½ in. tubing.

The time lapse in WELL-0030 was about 20 months during most of which the well was not flowing. The preliminary investigations in WELL-0030 show that the corrosion rate of N-80, 3 ½ in. tubing is approximately 3 mm/yr. However, if the well had not been shut-in, corrosion rate could have been higher. Overall, these rates of corrosion are alarmingly high but broadly agree with corrosion rates predicted by corrosion models.

MVRT Data Verification

1. MVRT vs. Caliper

Both, MVRT and Caliper have been run in three wells (WELL-0043, -0030, -0102) to provide a comparison between the two tools. Both logs were qualitatively comparable **(Fig. 14)** with the exception of WELL-0043 where the caliper log covered the last four joints of the damaged tubing, which were not covered by the MVRT due to borehole restriction. As mentioned earlier, the MVRT tool measures both internal and external corrosion while the caliper measures only the internal corrosion. Therefore, the corrosion recorded by the caliper is less than corrosion reported by the MVRT tool as shown in Fig. 14.

WELL-0043 was worked over and the retrieved tubing confirmed the observed corrosion on both logs. It is worth mentioning that due to severe corrosion, an expensive and lengthy fishing operation had to be performed to fish the corroded tubing out. **Fig. 15** and **Fig. 16** show caliper log summary chart of depth vs. corrosion data, and a picture of a piece of the pulled out tubing. It is clear that the caliper has correctly identified this badly corroded pipe.

2. MVRT Data vs. Surface Inspection

A detailed comparison of down-hole MVRT data and pulled-out tubing segments of corroded tubing have been carried out in at least one well, namely WELL-0057. The comparisons have validated the results of the MVRT for both internal and external defects. A visual inspection was conducted at site and samples of tubing, packers and completion assembly sent to the corrosion and inspection workshops for detailed examination. The samples have underdone both destructive and nondestructive testing to assess the type and the magnitude of the damage. Wall thickness, chemical composition, and visual inspection records have been made **(Fig. 17-18)**. It is important to note that the rig workover recommendation in this well was solely based on the MVRT log data. The log data proved to have appropriately identified the badly corroded pipe. The decision to pull the tubing out was surely correct. The workover, unlike WELL-

0043 and WELL-0082 (which will be discussed later in the paper), was trouble free and less costly.

The surface inspection study concluded that the damage observed was most severe at the bottom of the tubing as seen on the MVRT log. The tubing joints higher in the string have suffered significantly less damage; this was attributed to the presence of an adherent protective scale. Results again confirm the MVRT data.

Based on observed corrosion data, down-hole corrosion inspection guidelines and tubing inspection/quality control during completion/workovers for NK well completions have been established.

Impact-Economic Cost of Corrosion

Severe down-hole corrosion in production and injection wells, have so far resulted in six tubing and three casing failures and severe casing/tubing corrosions. Remediation of these wells has resulted in problematic, high cost workovers and in one case the loss of the productive interval and the associated reserves. Due to problematic and lengthy workovers, corrosion also impacts the well availability for production. These lengthy workovers cause significant production deferral.
Fig. 19 plots the cost of rig workover and time associated with each rig workover. It is obvious that Well-0043 and Well-0082 (failed completions due to corrosion) stand out in both cost and workover time compared to the normal rig workover cost of other similar completions. In Well-0043, the cost was 3X the normal rig workover cost due to corrosion related fishing/milling jobs. While in Well-0082 it was decided to reduce the rig workover cost by not continuing the fishing operations. This however led to the abandonment of a major producing section of the reservoir. The reserves of the abandoned zone can only be recovered by drilling a new well in the area.

From the experience learned from WELL-0043, which was a casing/tubing producer with both strings producing wet oil for some time, the economics of producing oil through casing versus corrosion risk should be evaluated, particularly if the casing production is expected to become wet.

Conclusions

- Corrosion is already a major issue in NK and will become more significant as water production increases.
- Down-hole corrosion needs to be properly monitored and managed to reduce operating cost and well down time.
- There is a fair correlation between water production and corrosion in NK.
- It has been observed that class 3 corrosion (50-75% wall loss) occurs mostly at watercuts above 25%.
- Corrosion has been seen in fairly low watercuts situations that may be partially related to mixing of tubing of different age and grade while re-completing the well.
- The MVRT results recorded down-hole have been verified against caliper and surface inspection. The comparison has validated MVRT results.
- In North Kuwait, MVRT has been used to monitor down-hole corrosion and make timely decision to pull out completions and avoid costly/problematic rig workover's.
- Through time lapse logging, MVRT has been used to estimate corrosion rate in North Kuwait completions. These estimates broadly agree with corrosion rates predicted by corrosion models.
- Based on observed corrosion data, down-hole corrosion inspection guidelines and tubing inspection/quality control during completion/workovers for North Kuwait well completions have been established.

Recommendations

- Along with monitoring, a comprehensive corrosion management plan such as "North Kuwait Corrosion Management Plan" need to be implemented in North Kuwait to manage corrosion cost and production impact.
- Timely rig workovers, based on down-hole corrosion monitoring data, are recommended to pull tubing before becoming problematic and costly.
- Mixing tubing of different grade and age in a well completion causes down-hole corrosion data interpretation problems and reduces effective life of the completion. It is recommended not to mix tubing of different grade and age.
- Investigating preventive methods including field-testing of corrosion-resistant alloys and chemical treatments need to be carried out as soon as possible to provide input for future material selection.
- Eliminating casing production to reduce the risk of casing corrosion should be considered particularly when the production is expected to become wet.
- It is recommended to obtain casing corrosion logs during rig workovers to cover casings and liners of the wells that have produced wet crude particularly those with casing production. In addition, it is recommended to monitor the liner of wet producers with through tubing calipers.

Acknowledgements

The authors are thankful to the management of Kuwait Oil Company and Ministry of Oil for their permission to publish this work. The authors would, also, like to thank the colleagues who reviewed the paper for their useful comments.

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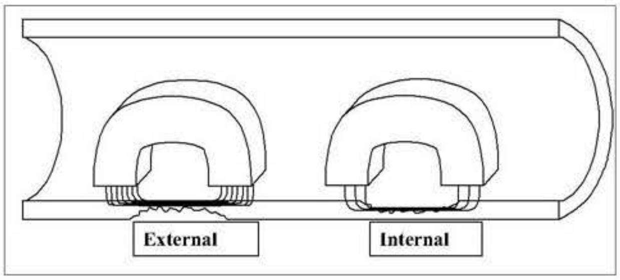


Fig. 1: MVRT measurement theory: Flux Leakage (FL) sensors alone cannot differentiate internal from external defects. To perform this function, Discriminator (DIS) sensors are deployed within a weak magnetic field that is completed through the tubing's inner surface.
External defects do not affect this flux path and therefore cause no DIS response. Internal defects, however, serve to alter the flow of flux in their vicinity, producing a characteristic DIS log response.

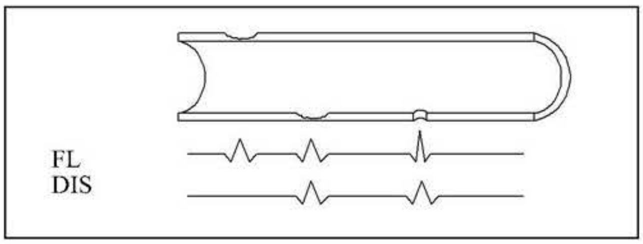


Fig. 2: MVRT tool response: The combination of FL and DIS sensors serves to identify the type and origin of tubular defects. An FL response alone indicates an external feature. An FL response in combination with a DIS response indicates an internal feature.

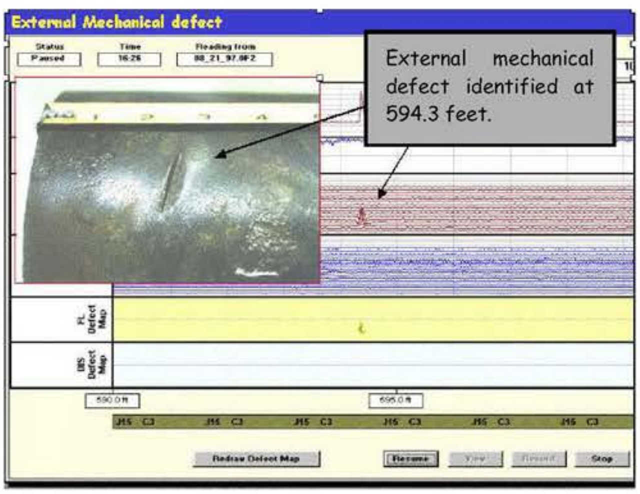


Fig. 3 The MVRT system produces digital bipolar waveforms, allowing metal gain anomalies versus metal loss to be determined from the log signatures.

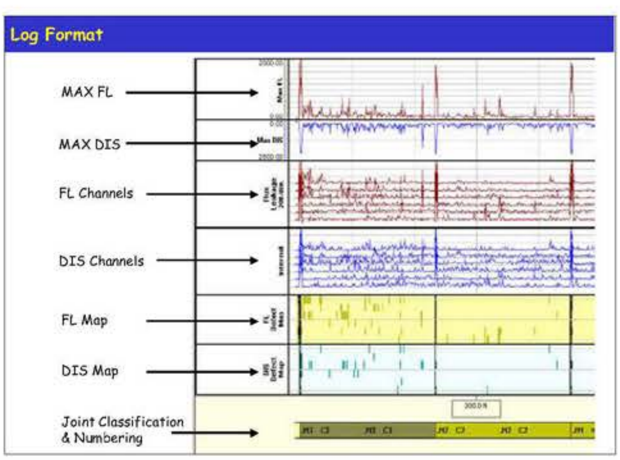


Fig. 4: MVRT log display format showing depth versus senor response, maps of internal and external defects, and a joint-by-joint classification of logged tubing string into four classes.

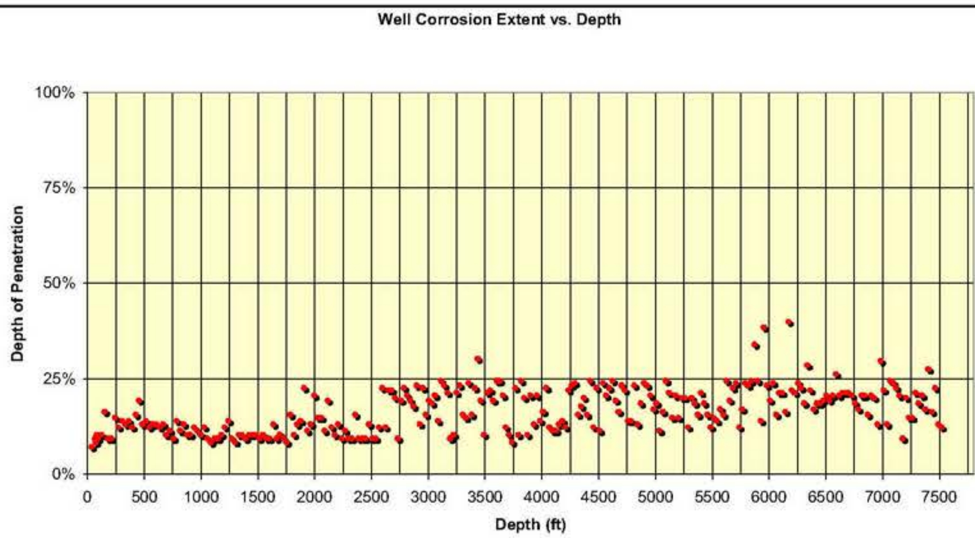


Fig. 5: MVRT log plot of wall loss vs. depth displaying overall tubing string conditions

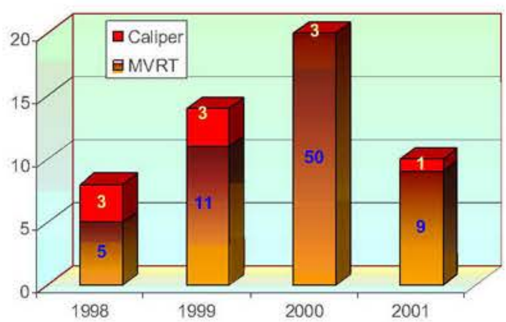


Fig. 6: Number of corrosion logs recorded in North Kuwait wells (tubing strings) vs. time

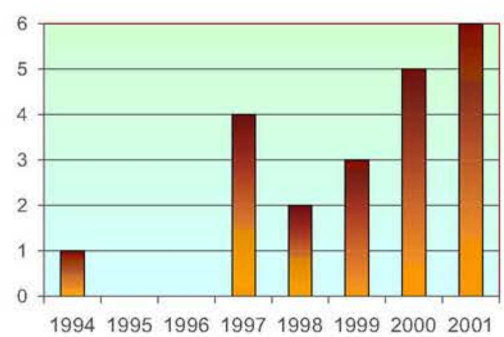


Fig. 7: Number of corrosion logs recorded in North Kuwait wells (casing strings) vs. time

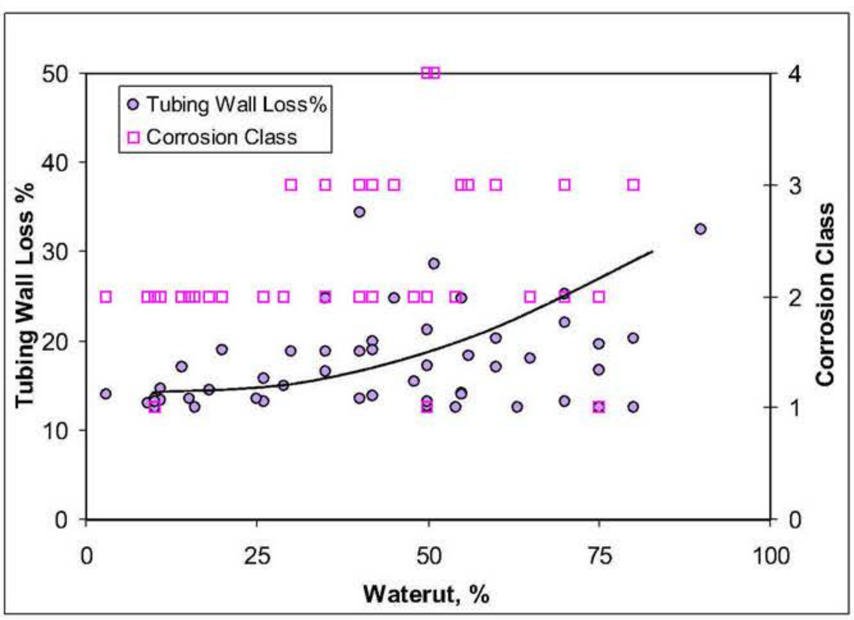


Fig. 8: A plot of stable watercut (%) of the logged tubing string vs. tubing wall loss (%) and the worst class of corrosion observed in the tubing.

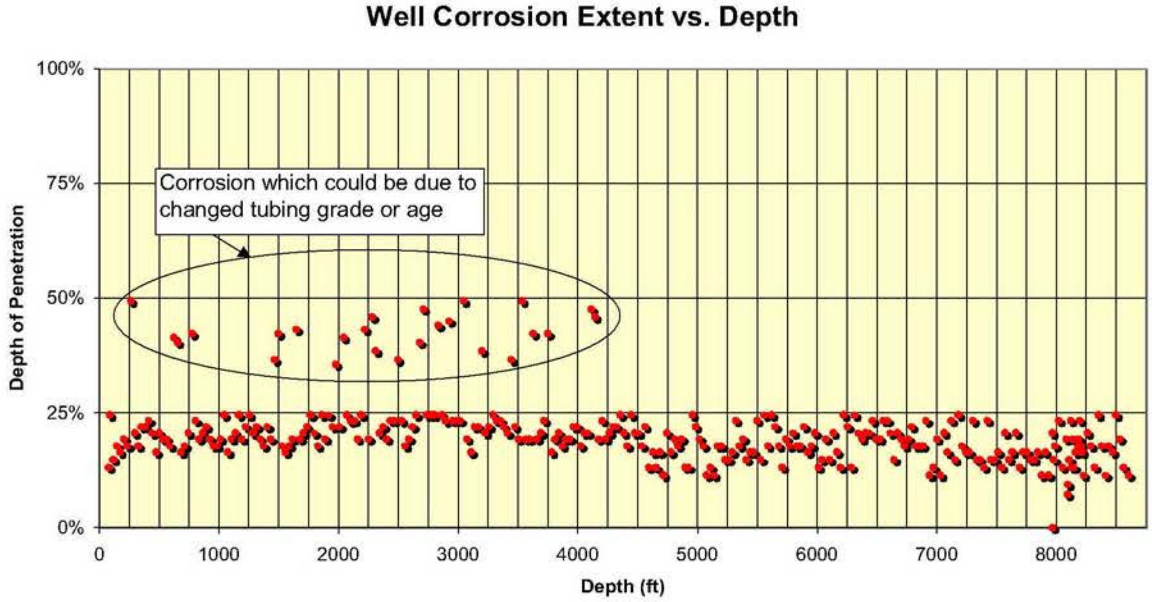
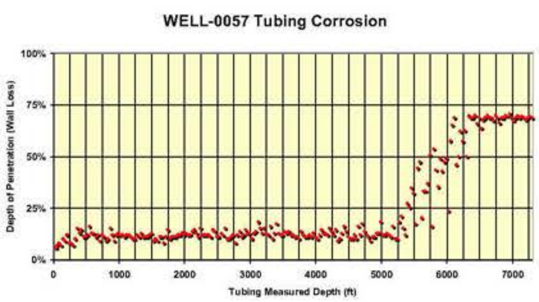


Fig. 9: An example of MVRT log in which the tubing shows corrosion in some joints. This corrosion interpreted by the MVRT could be as a result of completing the tubing with joints of different grade or age.



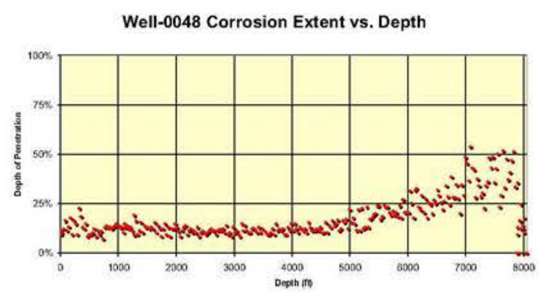


Fig. 10-11: Two examples of wells showing the depth vs. corrosion relationship. See increased corrosion after certain depth.

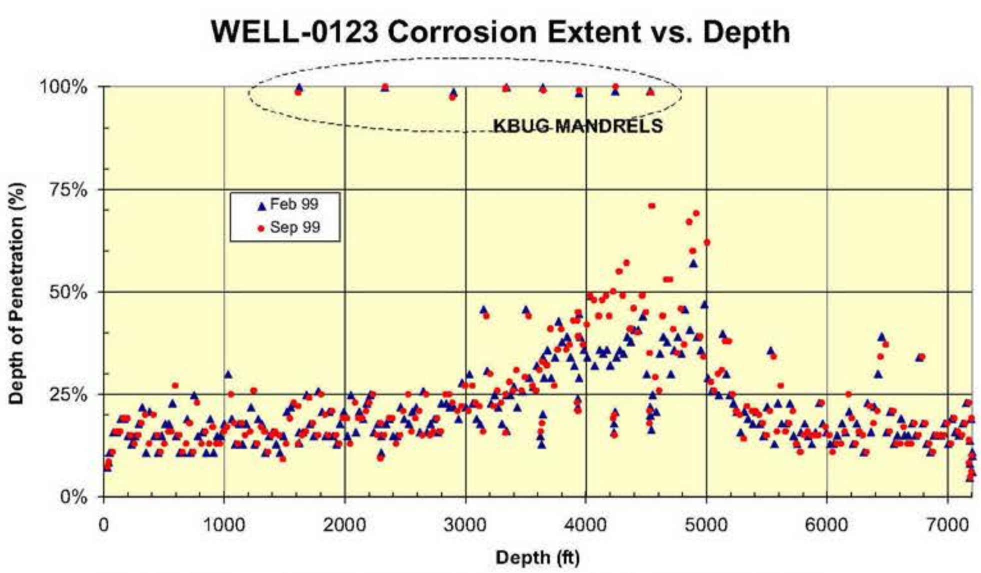


Fig. 12: WELL-0123 tubing penetration chart using time-lapsed corrosion logs

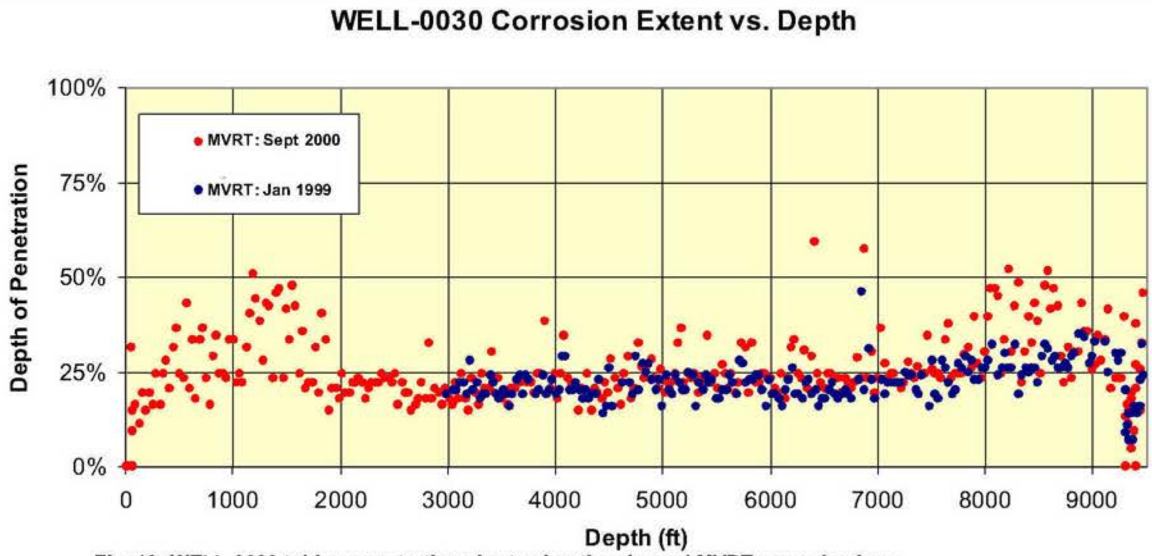


Fig. 13: WELL-0030 tubing penetration chart using time-lapsed MVRT corrosion logs

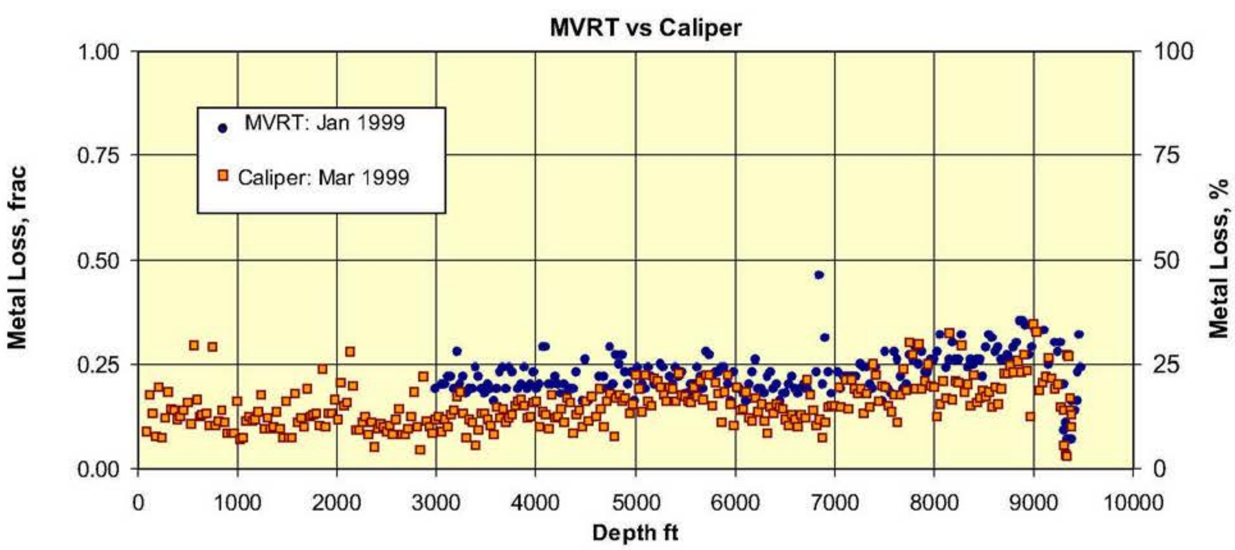


Fig. 14: WELL-0030 tubing penetration chart of the MVRT and caliper corrosion logs. Note that the caliper log is showing less corrosion than the MVRT log. This is because the MVRT tool measures both internal and external corrosion while the caliper measures only the internal corrosion.

Fig. 15: Piece of WELL-0043 pulled out tubing showing severe damage

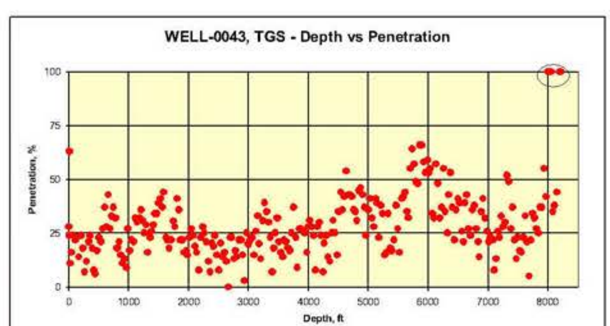


Fig. 16: WELL-0043 tubing penetration chart of the caliper log. Class 4 damage (100% wall loss in this case) is clearly identified by the caliper log

Fig. 17: WELL-0057 Tubing joint pin end

Fig. 18: WELL-0057 Tubing joint box end corroded section

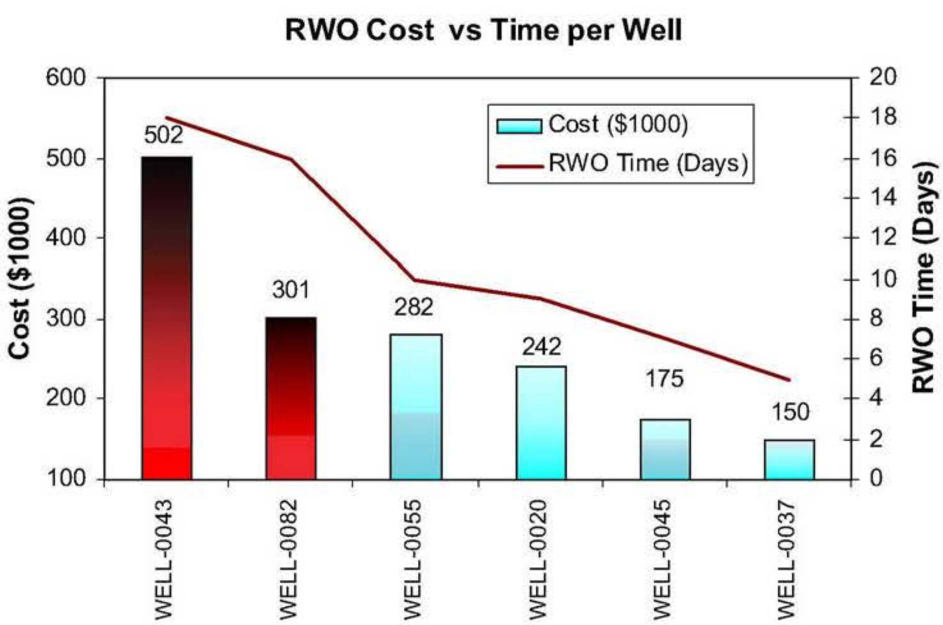


Fig. 19: Rig workover cost and the time associated with each rig workover for WELL-0043 and WELL-0082 compared to the normal rig workover cost of other similar completions.

Ex. II - 8

SPE 84828

The Importance in Developing a Surveillance Logging Quality Assurance and Quality Control Plan

Mark A. Newman, Columbia Gas Transmission

This paper was prepared for presentation at the SPE Eastern Regional/AAPG Eastern Section Joint Meeting held in Pittsburgh, Pennsylvania, U.S.A., 6–10 September 2003.

Abstract
A quality assurance and quality control (QA/QC) plan is important to the success of a surveillance logging program. A QA/QC Plan for a surveillance logging program can provide adequate and accurate information in assessing the level of pipe defects reported from casing inspection logs and can be used to record possible trends regarding individual casing inspection tools[1]. Measurements taken from pulled well casing can be used to enhance the analysis of general corrosion in areas of large-diameter pits. Over time the accuracy in estimating depth of penetration in large-diameter corrosion pits can be improved.

Introduction
With increased pressure to control costs and decrease spending, most companies will at some time or another review operating budget practices. For storage operators, a surveillance logging program may represent a significant portion of the operating and maintenance budget. To help control costs for a surveillance logging program, an operator may decide to alter the traditional log sweep or look at more effective ways to obtain the information they require. Altering the traditional log sweep simply means being more selective in choosing what log information the operator requires. A QA/QC plan is another way for an operator to verify information, to effectively manage the data, and to justify operating costs.

Quality Assurance / Quality Control Plan
The main focus of a surveillance logging QA/QC plan is to acquire pipe samples that contain identified defects and to validate the log analysis provided by the vendor. For the purpose of this paper, pipe samples will be compared to magnetic flux leakage casing inspection logs and specifically to that of the MicroVertilog (MVRT). Most comments will apply to all magnetic flux leakage casing inspection logs.

The key objective of a surveillance logging QA/QC plan is to ensure that the data being provided is adequate and accurate. A QA/QC plan can improve confidence in the data being generated, improve the data credibility with a contractor, and improve upon operational, product, or service efficiencies[1]. Information from the QA/QC plan can be used to better assess the level of pipe defects, recognize trends from the casing inspection logs, characterize possible errors in measuring tubular thickness, and monitor tool accuracy and data interpretation.

Casing Inspection Logs
A flux leakage casing inspection log such as the MVRT or Pipe Analysis Log (PAL) uses a computer software program to compare statistical data with the average depth of penetration over a specific area of investigation. Essentially, the software program compares recorded images with fixed images or examples of pipe defects as shown in Figures 1 and 2.

Figure 1 – Manufactured defects used for calibration.

Figure 2 - Manufactured defects used for calibration.

Tool Calibration. Calibration is important to quantifying measurements observed by the tool. Tool calibration is based on observed correlation between known defects in the pipe wall and the amplitude of a signal produced. Defects used for calibration are typically smooth, flat, or round uniform surfaces unlike the surfaces found when corrosion is present. Holes with three different diameters are drilled into the internal and external walls of the pipe, and are intended to represent typical defects found on pipe. The width-to-depth ratios used to drill the defects are typically 6:1, 4:1, and 2:1. The amplitude response for each of the calibrated defects is then plotted on an x-y chart of amplitude versus percent penetration. Curves are then fitted through the data points. The best-fit curve is in the form of $y=ax^b$. Calibration results in a general best-fit curve to represent the range of defects observed in the pipe samples.

To improve the curve fit, data points from corrosion samples can be collected and measured. With sufficient data points a new flux leakage amplitude curve (as shown in Figure 3) can be generated. The new amplitude curve can only be used to verify log analysis from the population that it was collected from. For example, data collected from general corrosion found on 5 ½", 17 ppf, J-55 casing can only be used to verify general corrosion on 5 ½", 17 ppf, J-55 casing.

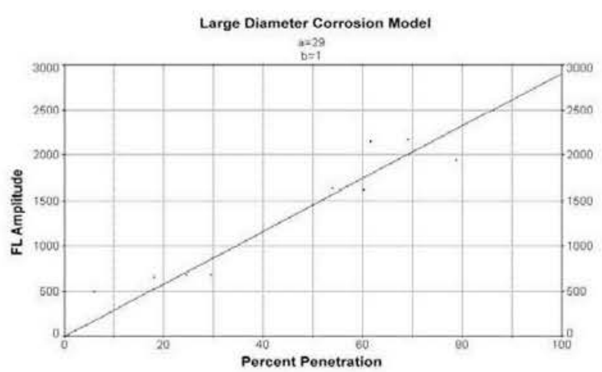


Figure 3 – Flux leakage amplitude curve developed for large-diameter corrosion.

Large-diameter Pit Corrosion. Most vendors would agree that large-diameter pit corrosion typically found in areas of general corrosion are the hardest to estimate and are generally overstated. The following are examples of large-diameter pit corrosion with a length and width greater than 1" and with an average depth of penetration greater than 60%. In each of the following examples the original log data was re-analyzed using a large-diameter pit corrosion model.

Example 1
Well A
Joint # 14
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.304 in.

<u>Log Measurements (Figure 4)</u>
Location – external
Corrosion model - general
Length – 1.7 in.
% penetration – 100%

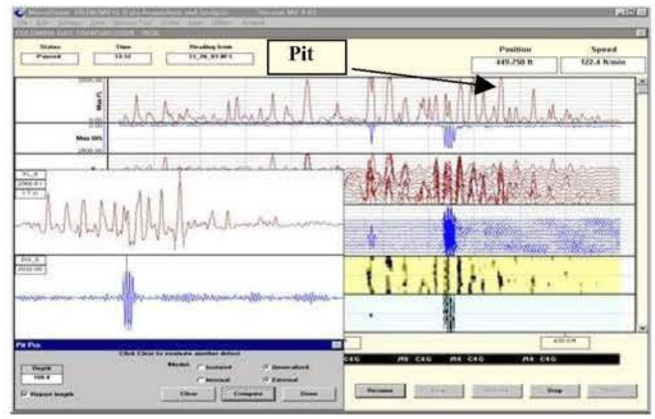


Figure 4 – Snapshot of Example 1 MicroVertilog taken from Pit Pro.

<u>Physical Measurements (Figures 5 and 6)</u>
Defect location – external
Defect depth – 0.21 in.
Defect width – 3.00 in.
Defect length – 1.75 in.
% penetration – 69.1%

Figure 5 – Digital image showing the defect where Example 1 physical measurements were taken.

Figure 6 - Digital image showing the defect where Example 1 physical measurements were taken.

Comments
Using the preliminary large-diameter corrosion model, the predicted depth of penetration from the MVRT data would be 75.2%.

Example 2
Well B
Joint # 2
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.301 in.

Log Measurements (Figure 7)
Location – external
Corrosion model - general
Length – 0.7 in.
% penetration – 83.5%

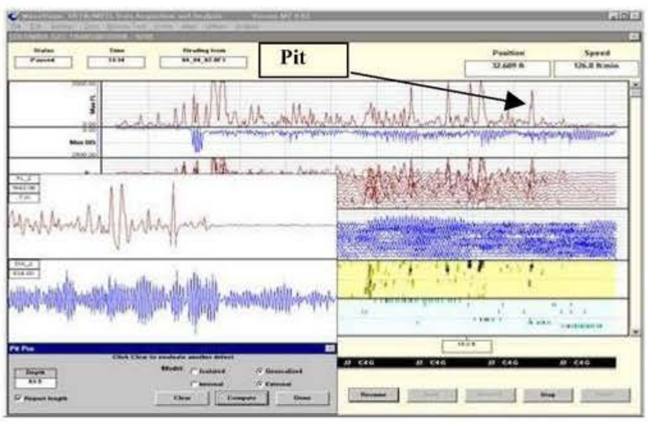


Figure 7 – Snapshot of Example 2 MicroVertilog taken from Pit Pro.

Physical Measurements (Figures 8 and 9)
Defect location – external
Defect depth – 0.162 in.
Defect width – 1.5 in.
Defect length – 1.0 in.
% penetration – 53.8%

Figure 8 - Digital image showing the defect where Example 2 physical measurements were taken.

Figure 9 - Digital image showing the defect where Example 2 physical measurements were taken.

Comments
Using the preliminary large-diameter corrosion model, the predicted depth of penetration from the MVRT data would be 56.6%.

Example 3
Well C
Joint # 7
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.356 in.

Log Measurements (Figure 10)
Location – external
Corrosion model - isolated
Length – 1.4 in.
% penetration – 42.9%

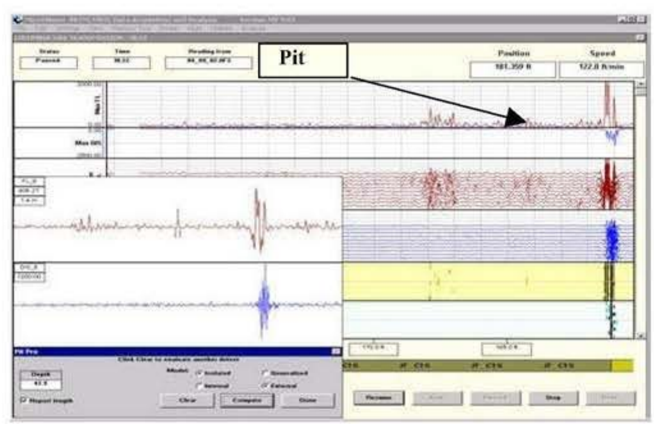


Figure 10 – Snapshot of Example 3 MicroVertilog taken from Pit Pro.

Physical Measurements (Figures 11 and 12)
Defect Location – external
Defect depth – 0.064 in.
Defect width – 1.5 in.
Defect length – 1.5 in.
% penetration – 18.0%

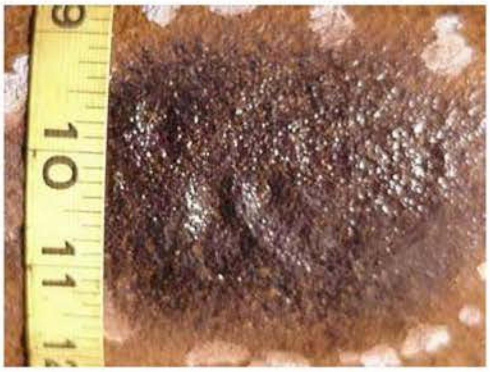


Figure 11 - Digital image showing the defect where Example 3 physical measurements were taken.

Figure 12 - Digital image showing the defect where Example 3 physical measurements were taken.

<u>Comments</u>
Using the preliminary large-diameter corrosion model, the predicted depth of penetration from the MVRT data would be 22.6%.

Example 4
Well D
Joint # 1
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.282 in.

<u>Log Measurements (Figure 13)</u>
Location – external
Corrosion model - isolated
Length – 1.4 in.
% penetration – 44.1%

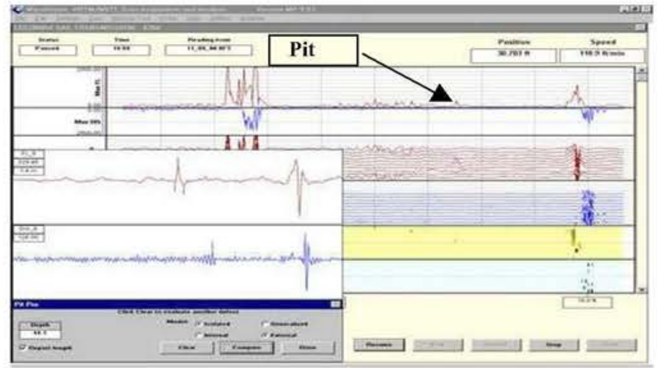


Figure 13 - Snapshot of Example 4 MircoVertilog taken from Pit Pro.

<u>Physical Measurements (Figure 14 and 15)</u>
Defect location – external
Defect depth – 0.07 in.
Defect width – 3.00 in.
Defect length – 2.00 in.
% penetration – 24.5%

Figure 14 - Digital image showing the defect where Example 4 physical measurements were taken.

Figure 15 - Digital image showing the defect where Example 4 physical measurements were taken.

<u>Comments</u>
Using the preliminary large-diameter corrosion model, the predicted depth of penetration from the MVRT data would be 23.9%.

Validation Measurements. Measurements taken from pipe samples with various types of corrosion, pipe defects, and mechanical defects should be used to validate log data. Validation is essential for verifying tool calibration and for monitoring the tool accuracy. Validations similar to the following examples are important and necessary functions for a QA/QC plan.

Example 5
Well B
Joint # 2
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.301in.

Log Measurements (Figure 16)
Location – external
Corrosion model - general
Length – 0.5 in.
% penetration – 43.4%

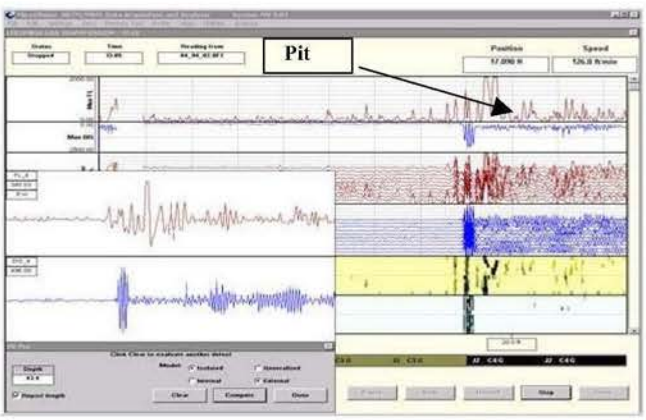


Figure 16 - Snapshot of Example 5 MircoVertilog taken from Pit Pro.

Physical Measurements(Figures 17 and 18)
Defect location – external
Defect depth – 0.135 in.
Defect width – 0.5 in.
Defect length – 0.5 in.
% penetration – 44.9%

Figure 17 - Digital image showing the defect where Example 5 physical measurements were taken.

Figure 18 - Digital image showing the defect where Example 5 physical measurements were taken.

Comments
This defect is an external pit located in close proximity to general corrosion. Notice how the pit is very symmetrical and resembles a calibration pit. Corrosion may have been produced by the presence of hydrogen sulfide.

Example 6
Well C
Joint # 7
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.356in.

Log Measurements (Figure 19)
Location – external
Corrosion model - general
Length – 1.4 in.
% penetration – 33.7%

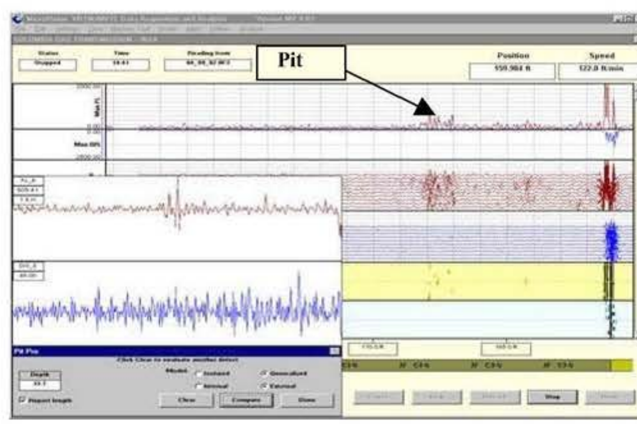


Figure 19 - Snapshot of Example 6 MircoVertilog taken from Pit Pro.

Physical Measurements (Figures 20 and 21)
Defect location – external
Defect depth – 0.092 in.
Defect width – 1.0 in.
Defect length – 1.5 in.
% penetration – 25.8%

Figure 20 - Digital image showing the defect where Example 6 physical measurements were taken.

Figure 21 - Digital image showing the defect where Example 6 physical measurements were taken.

Comments
This defect is an external pit located in a one-foot section of pipe with generalized corrosion.

Example 7
Well A
Joint # 27
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.311 in.

Log Measurements (Figure 22)
Location – internal
Corrosion model - isolated
Length – 0.4 in.
% penetration – 98.5%

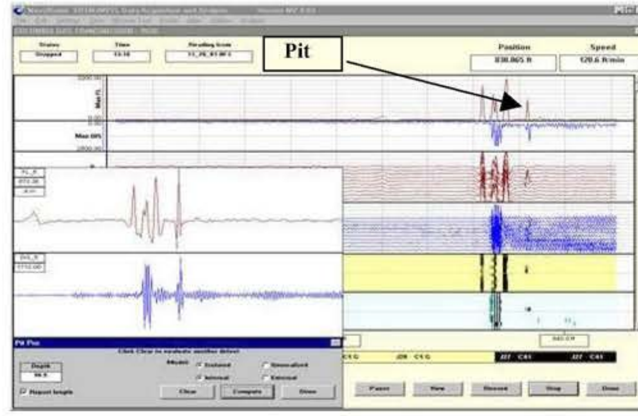


Figure 22 - Snapshot of Example 7 MicroVertilog taken from Pit Pro.

Physical Measurements (Figures 23, 24 and 25)
Defect location – internal
Defect depth – 0.09 in.
Defect width – 2.5 in.
Defect length – 0.25 in.
% penetration – 29.0%

Figure 23 - Digital image showing the defect where Example 7 physical measurements were taken.

Figure 24 - Digital image showing the defect where Example 7 physical measurements were taken.

Figure 25 - Digital image showing the defect where Example 7 physical measurements were taken.

Comments
This defect is a mechanical anomaly with a very deep, transverse pit that has a steep undercut shelf. Note the discriminator activity on the MVRT corresponds to an internal surface groove that is associated with severe laminations.

Example 8
Well E
Joint # 1
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.309 in.
Log Measurements (Figure 26)
Location – external
Corrosion model - isolated
Length – 0.5 in.
% penetration – 56.1%

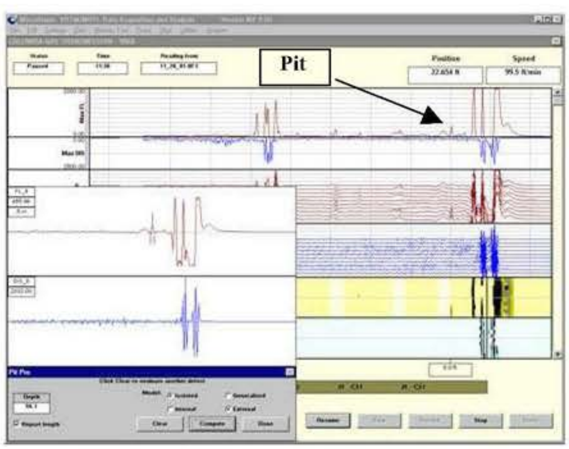


Figure 26 - Snapshot of Example 8 MicroVertilog taken from Pit Pro.

Physical Measurements (Figure 27)
Defect location – external
Defect depth – 0.017 in.
Defect width – 3.0 in.
Defect length – 0.25 in.
% penetration – 5.5%

Figure 27 - Digital image showing the defect where Example 8 physical measurements were taken.

Comments
This defect is a sharp-edged mechanical defect along the axis of the pipe. The proximity to the collar suggests that this is a tong mark.

Example 9
Well E
Joint # 12
Pipe size – 5.5 in.
Pipe weight and grade – 17 ppf, J-55
Nominal pipe wall – 0.304 in.
Measured pipe wall – 0.310 in.

Log Measurements (Figure 28)
Location – external
Corrosion model - general
Length – 0.5 in.
% penetration – 19.2%

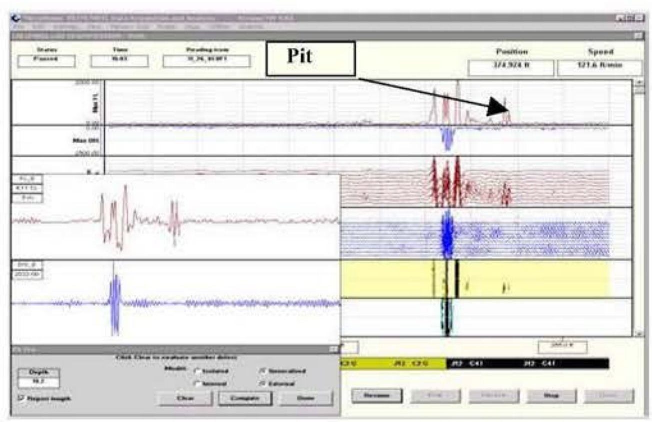


Figure 28 - Snapshot of Example 9 MicroVertilog taken from Pit Pro.

Physical Measurements (Figure 29)
Defect location – external
Defect depth – 0.032 in.
Defect width – 4.0 in.
Defect length – 0.38 in.
% penetration – 10.3%

Figure 29 - Digital image showing the defect where Example 9 physical measurements were taken.

Comments

This defect is a mechanical anomaly located 1.5' above the pin end of a joint. The original damage to the pipe is believed to be due to tongs or slips. Notice how corrosion appears to be forming around the damage area.

Conclusion

Developing a quality assurance and quality control plan is important to the success of a surveillance logging program. Information collected from pipe samples is critical for verifying the log analysis. As data reliability improves, an operator can better determine areas of concern and adjust the log frequency. Eventually, an operator can use the plan information to justify operating costs.

A QA/QC plan tends to enforce the need to collect and validate data in order to verify the reliability of the analysis of casing inspection logs. Due to the statistical nature of the log analysis, the operator can only improve the accuracy and reliability of the log information by comparing actual field measurements with log measurements. In some cases, an operator can greatly improve the log data by populating data points used to generate the amplitude curve. Collecting pipe samples is by far the most important component of a QA/QC plan.

As demonstrated by the examples provided in this paper, data reliability will eventually improve. An operator will develop a comfort level in accepting the information provided by a magnetic flux leakage casing inspection log, and begin to focus more attention on areas of known corrosion and can better determine the log frequency required to monitor well conditions.

It may be years before the actual benefits of the plan are apparent. One major reason is that most operators will need to start from the beginning, possibly ignoring previous data, in an effort to build a new, more dependable database. While past log data may be beneficial, data validation and corrections may not be possible. Over the life of the plan, an operator is sure to develop additional justification for surveillance logging operating costs.

Acknowledgements

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Ex. II - 9

SPE-175871-MS

Magnetic Flux Leakage (MFL) Technology Provides the Industry's Most Precise Pipe Integrity and Corrosion Evaluation, Accurately Characterizing Casing and Tubing Strength. Technology Overview and Case History

Wael El Sherbeny,PhD Ivo Nuic, Gasser Hasan,Abba Abdesslam, and Tharwat HassanePh.D. , Baker Hughes

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Abstract

The Magnetic Flux Leakage (MFL) Technique is the most commonly used technique to inspect large diameter transmission pipelines. A typical MFL inspection system uses permanent magnets to apply an axially oriented magnetic field to the ferromagnetic pipe material. The magnetic field is perturbed by a metal-loss region (usually caused by corrosion) to produce flux leakage outside the pipe, which can be measured by field sensors.

The magnetization system in an MFL inspection system should ideally produce a magnetic field that is strong enough to cause a measurable amount of magnetic flux to leak from the pipe material at metal-loss regions, uniform from inside to the outside surface of the wall thickness so that the measured signal is more linearly related to metal-loss depth, and consistent in magnitude along the length of a pipe so that flux leakage measurements can be compared at different locations during an inspection run.

In general, the field strength most strongly affects detection of metal loss defects while characterization of defect geometry requires a field that is strong, uniform, and consistent.

Improvements in the downhole hardware also provide more flexible and efficient data acquisition, reducing operating time while improving data accuracy and operational safety. In conventional magnetic flux leakage (MFL) tools, the flux leakage sensors are coils; in the "high-resolution" tool, the coil is replaced by multiple "Hall Effect" sensors.

The HR Vertilog service uses MFL measurements to identify and quantify internal and external corrosion defects. The overlapping arrays of flux-leakage sensors and discriminator sensors offer full circumferential inspection of the tubing or casing string. This process differentiates between metal-loss (corrosion) and metal-gain (hardware) Features, and distinguishes between general corrosion and isolated pitting. Paper represents technology overview and field cases history

Corrosion, corrosion root-causes and corrosion inhibitors

Corrosion is the destruction of metal through electrochemical action between metal and its environment. About 75 to 85 percent of drillpipe loss can be attributed to corrosion. Other areas affected by corrosion include pump parts, bits, and casings. Factors affecting corrosion include:

- Temperature. Corrosion rates can double with every 55° increase in temperature.
- Velocity. The higher the mud velocity, the higher the rate of corrosion due to film erosion (oxide, oil, amine, etc.).
- Solids. Abrasive solids remove protective films and cause increased corrosive attack.
- Metallurgical factors. Mill scale and heat treatment of pipe can cause localized corrosion.
- Corrosive agents. Corrosive agents such as oxygen carbon dioxide and hydrogen sulfide can increase stress cracking corrosion and lead to pipe failure.

The corrosion that occurs because of these various factors falls into four categories:

- Uniform corrosion results in an even corrosion pattern over surfaces.
- Localized corrosion results in a mesa-like corrosion pattern over surfaces.
- Pitting is a highly localized corrosion that results in the deep penetration of surfaces.
- Mechanical damage dislocates or completely removes surfaces.

Drilling-fluid corrosive agents

Corrosive agents found in drilling fluids include:

- Oxygen (O2)
- Hydrogen sulfide (H2S)
- Carbon dioxide (CO2)
- Bacteria
- Dissolved salts (Zn+, Br−, etc.)
- Mineral scale (CaSo4, FeCO3

Oxygen

Oxygen causes a major portion of corrosion damage to drilling equipment. Oxygen removes protective films such hydrogen; this action causes accelerated corrosion and increased pitting under deposits. The four primary sources of oxygen are:

- Water additions
- Actions of mixing and solids control equipment
- Aerated drilling fluids
- The atmosphere

Water additions

Water added to a drilling fluid during normal drilling operations can contain dissolved oxygen. Very small concentrations of oxygen (<1 ppm) can cause severe corrosion by setting up differential aeration cells that can show preferential attack with pitting under barriers or deposits. The primary corrosion by-product of low oxygen concentrations is magnetite. The products recommended for the removal of dissolved oxygen are called oxygen scavengers

Actions of mixing and solids control equipment

Mixing and solids-control equipment can cause aeration of the drilling fluid during drilling operations. For example, aeration occurs as mud falls through the shaker screen or when hopper or mud guns are discharged above the surface of the mud in the pits. To reduce the amount of oxygen injected into drilling fluid by mixing and solids-control equipment, follow these guidelines.

- Use a premix tank to mix mud when possible.
- Maintain the minimum mud volume.

- Operate mud-mixing pumps, especially the hopper, only when mixing mud.
- Keep the packing tight on centrifugal pumps.
- Keep the mud in the suction pit deep enough to keep the mud pump from pulling in air.
- Keep discharge below the mud surface when moving mud from the reserve pit.
- Ensure guns discharge below the mud surface.
- Ensure the degasser and desander discharges are below the mud surface.

The products recommended for treating drilling fluid containing oxygen because of mixing and solids-control equipment are called oxygen scavengers.

Aerated drilling fluids

Aerated drilling (foam and mist drilling) fluids require the use of passivating (oxidizing) inhibitors to combat corrosion due to oxygen. The product recommended for inhibiting oxygen in aerated drilling fluids is BARACOR 700.

Atmosphere

The atmosphere is another source of oxygen. The main by-product of atmospheric corrosion is iron oxide rust. To prevent atmospheric corrosion, wash the pipe free of all salts and mud products and then spray or dip the pipe in an atmospheric corrosion inhibitor. The product recommended for inhibiting atmospheric corrosion is BARAFILM.

Hydrogen sulfide

Hydrogen sulfide can enter the mud system from:

- Formation fluids containing hydrogen sulfide
- Bacterial action on sulfur compounds in drilling mud
- Thermal degradation of sulfur-containing drilling-fluid additives
- Chemical reactions with tool-joint thread lubricants containing sulfur

The corrosion process, bacterial action, and thermal degradation of organic additives can generate hydrogen sulfide in drilling fluids. Hydrogen sulfide is very soluble in water. Dissolved hydrogen sulfide behaves as a weak acid and causes pitting. Another problem with hydrogen sulfide is that some of the hydrogen ions at the cathodic areas may enter the steel instead of evolving from the surface as a gas. This process can result in hydrogen blistering in low-strength steels. Both the hydrogen and sulfide components of hydrogen sulfide can bring about drillstring failures.

Hydrogen sulfide corrosion is mitigated by increasing the pH to above 9.5 and by using sulfide scavengers and film-forming inhibitors. The products recommended for combating corrosion due to hydrogen sulfide are called H2S scavengers

Note: Hydrogen sulfide and carbon dioxide are often encountered in the same geologic formation; therefore, design treatments to deal with both contaminants simultaneously.

Treatment

$$\frac{682 \times P_m}{SG\ brine} = mg/l\ H_2S$$

$$mg/l\ H_2S \times 0.00602 = Kg/\ m^3\ ZnCO_3$$

Carbon dioxide

Carbon dioxide is found in natural gas in trace-element and major-element quantities. When combined with water, carbon dioxide forms carbonic acid and decreases the water's pH, which increases the water's corrosivity. While carbon dioxide is not as corrosive as oxygen, it can cause pitting. A large drop in pH, combined with a negative test for hydrogen sulfide, is an indication that CO2 has contaminated the mud.

Maintaining the correct pH is the primary treatment for carbon dioxide contamination. Either lime or caustic soda can be used to maintain pH, although, lime is preferred. The following table provides the reactions for each of these treatments.

Treatment	Reaction
Caustic soda	2 NaOH+CO2→2H2O+Na2CO3
Lime	Ca(OH)2+CO2+H2O→2H2O+CaCO2

Treatment with caustic soda produces sodium carbonate, which is soluble and can create mud problems. Treatment with lime, on the other hand, produces an insoluble calcium-carbonate precipitate and water.

Note: To maintain pH in water-based muds, use BARACOR 95 instead of a lime. BARACOR 95 is a liquid amine compound that serves as a carbon-dioxide scavenger. This treatment is particularly useful with a polymeric system that may be pH-sensitive. However, keep in mind that it does not treat for hydrogen sulfide.

In addition to maintaining pH, use a filming amine inhibitor to mitigate corrosion caused by carbon dioxide. The product recommended for mitigating corrosion is BARAFILM.

Note: Hydrogen sulfide and carbon dioxide are often encountered in the same geologic formation; therefore, design treatments to deal with both contaminants simultaneously.

Bacteria

Microorganisms can cause fermentation of organic mud additives, changing viscosity and lowering pH. A sour odor and gas are other indicators that bacteria are present. Degradation of mud additives can result in increased maintenance costs.

The by-products of bacteria are carbon dioxide and hydrogen sulfide. The presence of bacteria is determined by the phenol-red test. Microbiocides are used to control bacteria in drilling environments. The products recommended for controlling bacteria are:

ALDACIDE G
Isothiazotone-based biocide powder

Dissolved salts

Dissolved salts increase corrosion by decreasing the electrical resistance of drilling fluids and increasing the solubility of corrosion by-products. These by-products can cause a film to form on the surface of the metal.

Mineral scale

Mineral scale deposits set up conditions for local corrosion-cell activity. The continuous addition of scale inhibitor can control the formation of scale deposits. The product recommended for inhibiting the formation of scale deposits is Scale-inhibitors

Brine fluids

The corrosivity of a brine fluid depends on its type. Brines fall into two categories: monovalent and divalent.

Monovalent brines

Monovalent brines contain salts that have monovalent cations; such as salts include sodium chloride, potassium chloride, potassium bromide, and sodium bromide. Potassium bromide and sodium bromide are especially effective in calcium-sensitive formations and in formation where carbon dioxide gas might react with calcium brines to create a calcium-carbonate precipitate. Monovalent brines generally show low corrosivity, even at temperatures exceeding 400F (204C).

Divalent brines

Divalent brines contain salts that have divalent cations; such as calcium chloride, calcium bromide, and zinc bromide. A divalent brine might consist of single salt or a blend of salts, depending on the required brine density and crystallization point. The corrosiveness of these brines depends on their density and chemical composition. Laboratory data show that the addition of calcium chloride lowers the rate of corrosion, while the addition of zinc bromide rapidly increases the rate of corrosion.

Corrosive agents

When working with brine based fluids, the two corrosive agents to monitor are oxygen and hydrogen sulfide.

Oxygen

The oxygen content of fluids is difficult to determine, and most engineers in the field do not have access to the proper equipment. Because the dissolved oxygen content varies as conditions change, it is difficult to select a set feed rate of an oxygen scavenger to remove a known concentration of oxygen.

Laboratory tests show that the oxygen content of calcium chloride, calcium bromide, and zinc bromide brines is very low. The solubility of gases in a liquid is directly related to the total dissolved-solids concentration of that liquid. The higher the dissolved-solids content, the lower the solubility of gases in the liquid. The following table lists oxygen concentrations measured in stock brine at room temperature.

Brine	Oxygen concentration, ppm
11.6 lb/gal $CaCl_2$	0.1 to 0.2
14.2 lb/gal $CaBr_2$	0.05 to 0.1
19.2 lb/gal $Ca/ZnBr_2$	0.4 to 0.6

Note: In a well at elevated temperatures, the oxygen content should be much lower.

Some products used as oxygen scavengers contain sulfides that react with the dissolved oxygen in fluids to form sulfates, eliminating the corrosive effects of the dissolved oxygen. Calcium brines should not be treated with oxygen scavengers containing sulfides because chemicals could precipitate calcium scale and cause problems. In a packer-fluid application where there is a static system with no aeration of the fluid, the dissolved oxygen content is so low that an oxygen scavenger usually is not required.

Hydrogen sulfide

In solids-enhanced systems, the most often used hydrogen-sulfide scavenger is zinc carbonate. The zinc reacts with the soluble sulfide ions to form zinc sulfide, which is insoluble and precipitates as an unreactive compound. In solids-free systems, soluble zinc bromide salt serves the same function and absorbs the hydrogen sulfide.

In operations where hydrogen-sulfide contamination is expected, offset the hydrogen sulfide's acidic nature by maintaining a proper pH in the brine, as outlined in the following table.

Brine	Recommended pH		Treatment
Nonzinc	7.0	7.0	Caustic soda or lime
Calcium	7.0 – 10.5	7.0 to 10.5	Caustic soda or lime
Zinc	3.0 – 5.0	3.0 to 5.0	Lime

Technology Overview

The Digital Vertilog™ service (DVRT™) uses DC flux leakage measurements to determine the depth of penetration of casing defects in the primary casing string, providing rapid 360° pipe inspection. The DVRT service helps operators monitor—when deployed for periodic surveys—the progress of corrosion within tubulars. This information is invaluable when considering remediation or well abandonment.

12 or 24 separate channels are sampled up to 32 times per foot to provide a complete circumferential survey of corrosion extent. The waveforms of these channels are preserved during logging in order to discriminate between actual corrosion and well completion equipment. Two additional channels of eddy current measurements are provided. These channels are used to determine whether flux leakage activity is occurring on the inner or outer surface of the casing.

Applications

Performs rapid 360° pipe inspection

Detects corrosion and evaluates its extent

Determines the effectiveness of cathodic protection and corrosion inhibitors

Confirms location of leaks and perforations

Assists determining the financial value of casing when considering well abandonment

Benefits

Ensures continuous production with accurate evaluation of remaining strength of casing and tubing

Delivers survey information via high logging speeds, reducing rig time

Features

Available in 4½- to 22-in. tubular sizes

Detects centralization of primary casing string at the bottom of the next casing string

Checks casing string makeup and joint lengths; locates well completion equipment

Overlapping sensor arrays insure complete coverage inside and out

Combination of FL and DIS sensors differentiate internal and external defects during interpretation

Tool series	2938	2939
Casing range and weight	$4^1/_2$ in. (9.5ppf) to 5 in. (24.1 ppf)	5 in. (11.5ppf) to $6^5/_8$ in. (32 ppf)
Instrument length	18 ft (5.49 mt)	18 ft (5.49 mt)
Instrument weight	382 lb (173.64 Kg)	405 lb (184.09 Kg)
Logging speed	125 ft/min (40 M/min)	125 ft/min (40 M/min)
Maximum pressure	12,000 psi (82.7 Mpa)	15,000 psi (103.4 Mpa)
Maximum temperature	280°F (138°C)	280° F (138°C)

Digital Vertilog Service

Tool series	2940	2941
Casing range and weight	$6^5/_8$ in. (20 ppf)	$8^5/_8$ in. (40 ppf) to 22 in.
Instrument length	18 ft (5.49 mt)	18 ft (5.49 mt)
Instrument weight	625 lb (284.09 Kg)	838 lb (380.91 Kg)
Logging speed	125 ft/min (40 M/min)	125 ft/min (40 M/min)
Maximum pressure	15,000 psi (103.4 Mpa)	15,000 psi (103.4 Mpa)
Maximum temperature	280°F (138°C)	280°F (138°C)

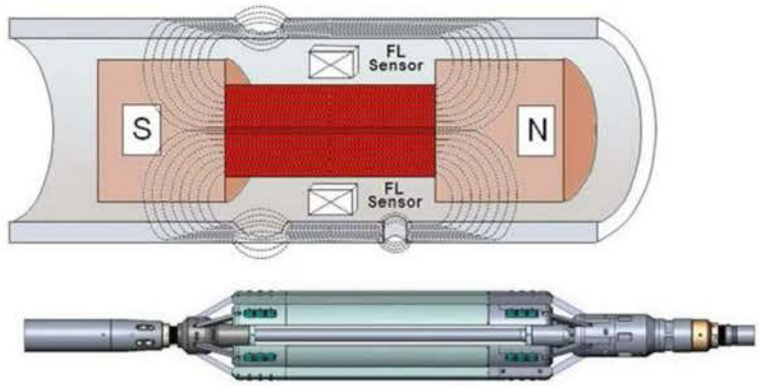
Tool series specifications

HRVRT – Success

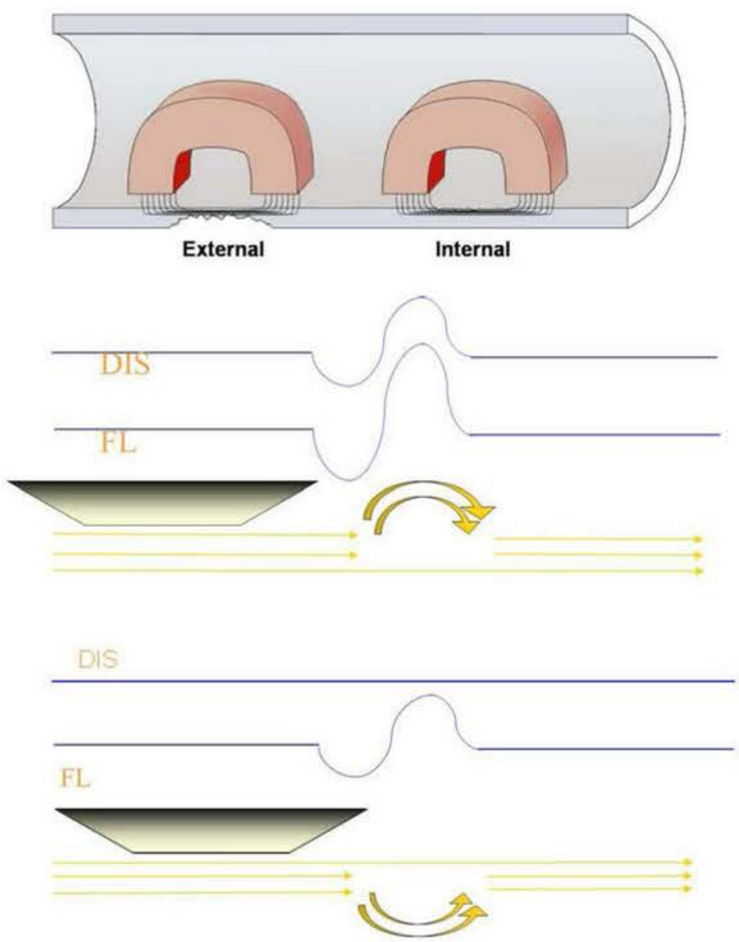
- 1200+ Operational jobs per year worldwide
- 95% Market Share in gas wells in USL
- 345°F Maximum DH Temperature for HRVRT job till date
- Service covering range from 4 ½” to 9 5/8”
- Global approval by more than 70 NOC/IOC
- Wireline, Tractor and CT Conveyance jobs conducted

Measurements theory or Physics behind the technology

- A permanent magnet circuit is completed through the tubing, producing a very high magnetic flux density within the tubing body wall.



FL sensors alone cannot differentiate internal from external defects. To perform this function, Discriminator (DIS) sensors are deployed within a weak magnetic field that is completed through the tubing's inner surface.



How do we get such a high resolution?

Increased circumferential and axial resolution

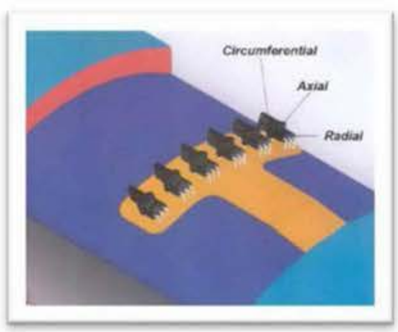
Highest number of sensors
144 FL, 48 DIS in 4 ½″ tool
144 FL, 48 DIS in 5″ – 5 ½″ tool
288 FL, 96 DIS in 7″ – 9 ⅝″ tool
Smaller sensors (1 ¼″ coil to. 25″ Hall Sensors)

Multi-axial Sensors

Results in better defect description

Quantifiable defect description

Field verifiable calibration
Increased accuracy for length, width and depth of penetration determination
Results in better input into burst pressure calculations
Data base output for long term data storage and integration into other data systems

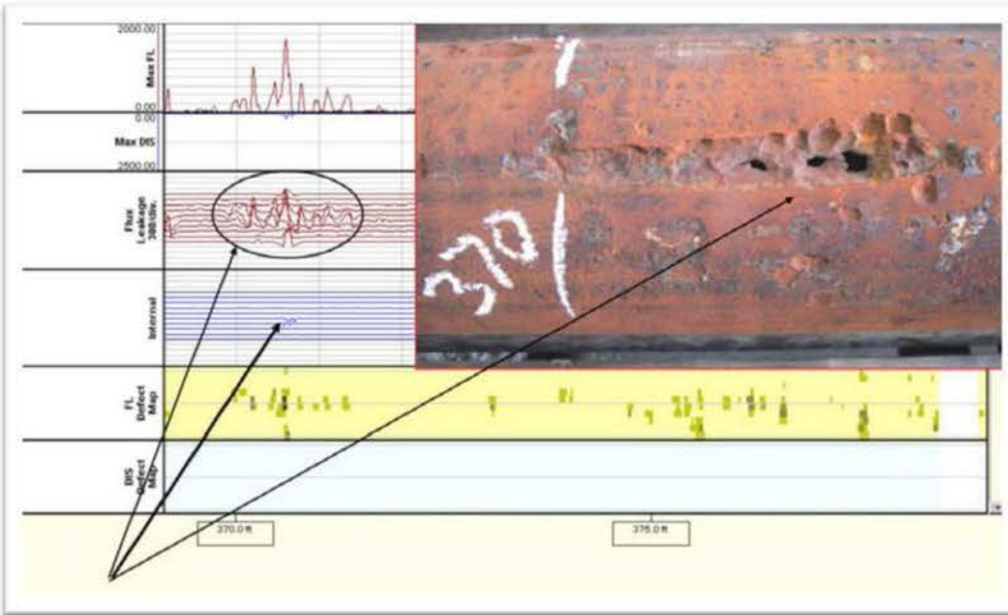


Uses tri-axial sensors at 10 samples/foot providing defect geometry and depth of penetration
100% coverage
192 sensors in 4½- and 5½-in. tools
384 sensors in 7- to 9⅝-in. tools

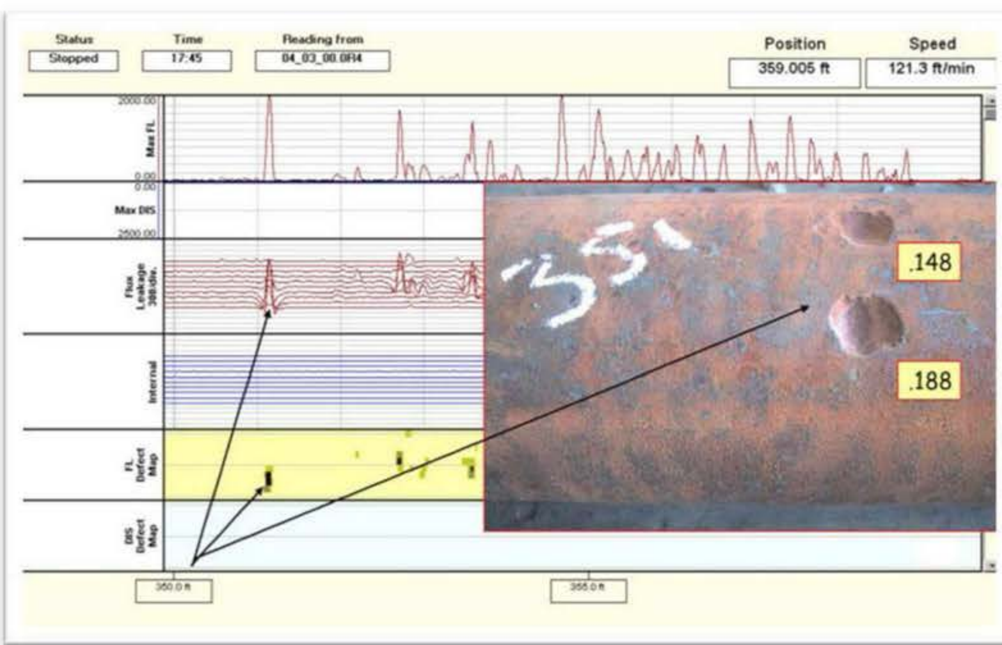
High-resolution report provides executive summary, feature list, hardware reports, histograms, feature type, and quantifiable LxWxD with burst pressure calculations for each feature

Case Histories

Case I

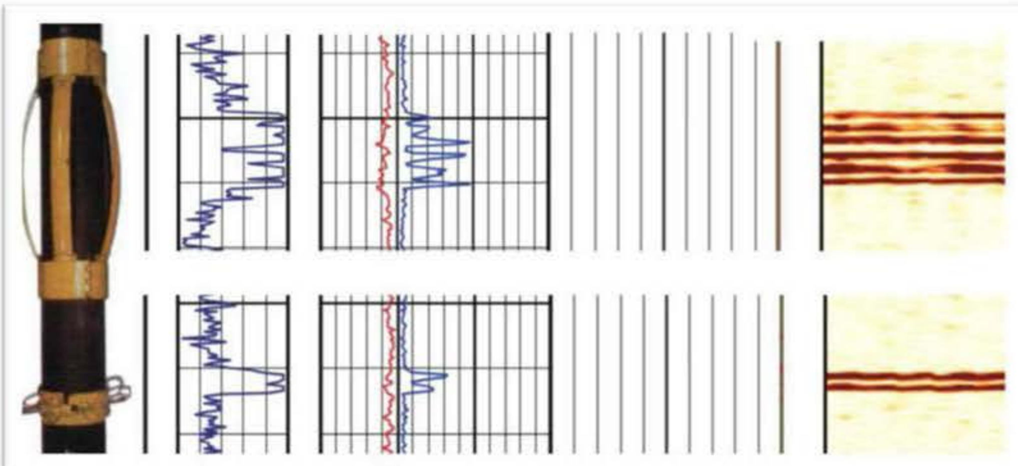


Several external pits interconnected, observe the response of discriminator



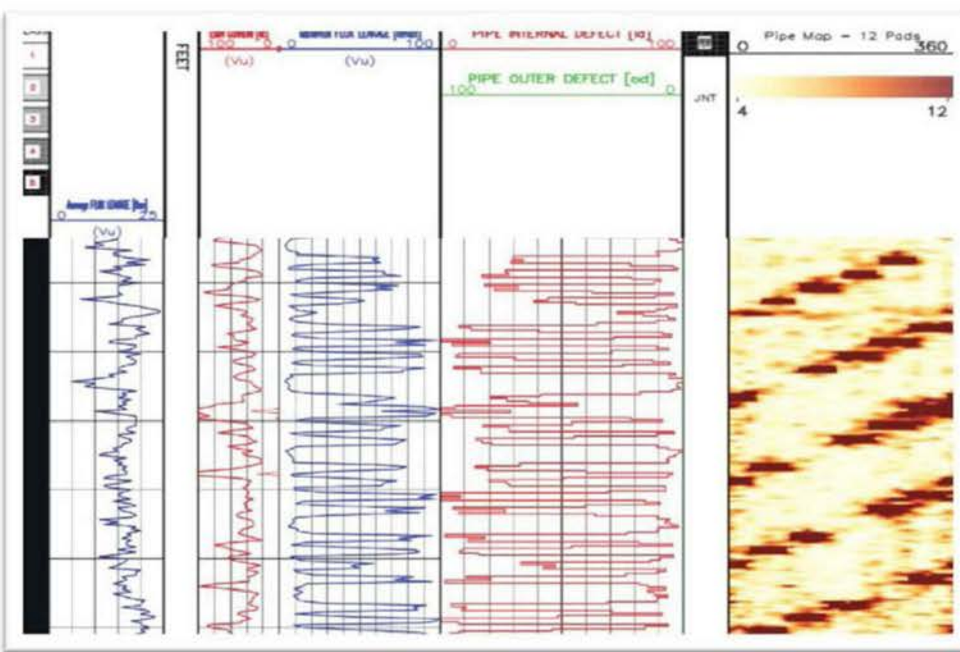
Two external pits

Case II



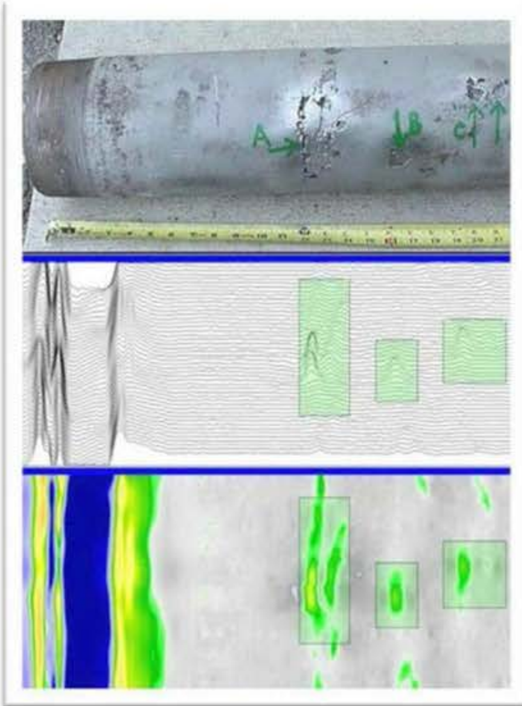
Accessories log example

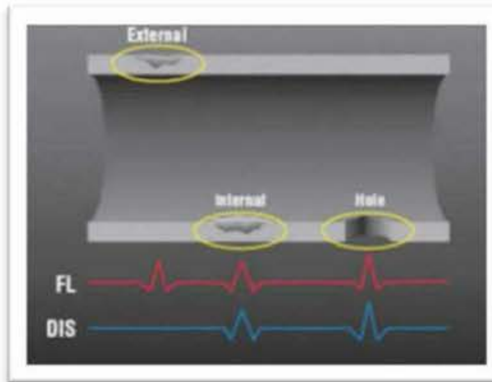
Case III

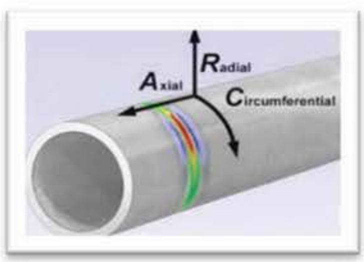


Perforating log example

Case IV – Algerian Case History







The HRVRT service performs an inspection over the radial, axial, and circumferential axes.

Typical flux leakage (FL) and discriminator (DIS) – sensor response to common defects—the FL sensors respond to internal and external anomalies, while the DIS sensors respond to internal anomalies only.

An operator working in the southeastern part of the Saharan platform in Algeria strongly suspected that major corrosion damage in the casing of an old well would complicate plans to restore production. When logging operations performed by another service company failed to find any defects or anomalies, the operator contacted Baker Hughes to get a second opinion.

Working at the wellsite, a Baker Hughes geoscientist used the HRVRT™ high-resolution vertilog service to quickly and accurately quantify the extent and penetration depth of corrosion defects.

The HRVRT service also evaluated the burst pressure of tubulars to help manage the well integrity risk. Based on this data, the operator was able to reduce production downtime by cutting the pipe and pulling it to the surface to replace the defective casing section instead of performing a time-consuming and more expensive remediation. As a result, the operator now plans to use the HRVRT service on future wells in its recovery program.

Benefits

- Quickly and accurately assessed damage to casing of well scheduled to go back into production
- Prevented production downtime by allowing operator to plan intervention instead of remediation

Background and challenges

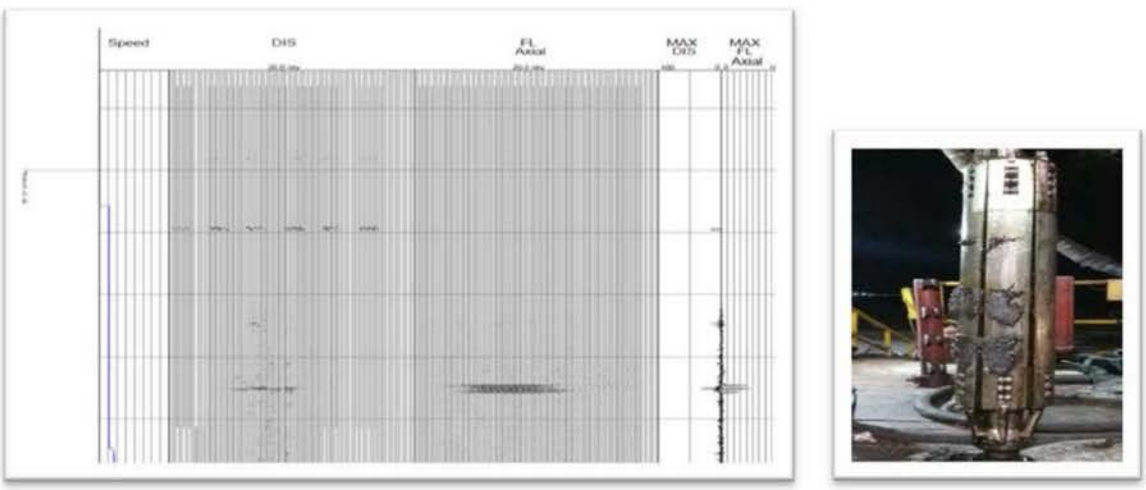
Southeastern Saharan platform in Algeria. Review state of the casing in an old well after logging operations by another service company failed to discover any defects or anomalies.

Baker Hughes solution and results

Used HRVRT service to quickly and accurately identify and quantify the extent and penetration depth of corrosion defects in tubulars.

Evaluated burst pressure to manage well integrity risk. Success of the operation has led operator to use the HRVRT service for other wells in the recovery program

Case V – ME Region Case History



HR Vertilog – Magnetic Flux Leakage Inspection

HVRT run on 7″ Liner showed no corrosion and was able to identify all the perforations. The client was questioning the HVRT results because of the metal debris collected by the magnet. The client compared our data with a competitor corrosion tool and it showed exactly the same results; it means no corrosion then he did not change the perforation plan. Metal debris collected by magnets meant for 7″ liner could have easily been collected from the 9 5/8″ section (even though it's not centralized in the larger casing)

Metal debris could be corrosion from the 9 5/8″ section which has fallen lower into the 7″ section.

Conclusion and Summary

MFL has a lot of advantages for the industry as it is consider the highest resolution corrosion identification in the industry, pit resolution. Quantifiable defect description and it is the widest coverage range of casing ID.

MFL is the Fastest logging speed in the industry, up to 200 ft/min, with flexibility of variable logging speed.

Advanced analysis from three axes of magnetic flux leakage data feature based reporting Control lines orientation capability, ControlView Memory acquisition capability. Magnetic flux leakage "MFL" tolerant for BHT up to 350 F. information from MFL, could be utilized as a guidance regarding not only the adequate corrosion inhibitors, brine and drilling fluids to be utilized in the future wells in the same fields, but also gives a visibility regarding proper corrosion inhibitors additives for injected waters.

Acknowledgement

Sincere thanks are extended to Baker Hughes for the permission to present this paper. Thanks are also extended to the Baker Hughes field personnel for their efforts in executing this wireline Technology Geoscience team involved in processing and interpretation.

About the Author

Wael El Sherbeny, is currently Business Development Manager – RDS. Wael holds BSc. In Geology, MSc. in Wellbore instability, clay mineralogy and formation pressures for Gulf of Suez and Red Sea Miocene age rocks, Cairo University, accredited from Texas Tech. University, Department of Petroleum Engineering, Houston, Texas. PhD in drilling fluids, reservoir damage and chemical remediation and geomechanics "sand production prediction", Mediterranean sea, Tertiary age, Ain Shams University, Cairo, Egypt. Wael is an SPE & SPWLA member and worked along MEAP and Africa regions. Wael has more than 20 years in oil industry in technical and managerial positions; covering mud logging, Petrophysics, drilling & completion fluids, chemical stimulation and reservoir damage, and recently Geoscience, Geology "borehole imaging and mineralogy, geomechanics with Baker Hughes. Wael is an author and co-author for almost 37 published papers covering many aspects in drilling and G & G application and production technology. Wael is a technical steering committee member for SPE, NATC, North Africa technology exhibition and conference.

Tharwat Hassane, is currently Geoscience manager for Qatar – RDS. Tharwat holds BSc. In petroleum engineering and PhD in reservoir engineering from Heriot Watt University UK. Tharwat is also working as a petrophysical advisor and has more than 20 years oil industry in technical and managerial positions

Gasser Hassan is a Petroleum Engineering Advisor with more than 10 years of experience in the industry, currently he is the Geoscience country lead of Baker Hughes in Saudi Arabia. His experience includes reservoir engineering & formation evaluation and he has worked in various locations in the middle east Gasser holds a Bsc. degree in petroleum engineering from Cairo University

Ex. II - 10

Specifications and requirements for in-line inspection of pipelines

Version 2016

PIPELINE
OPERATORS FORUM

Contents

1 Introduction

This document specifies the advised operational and reporting requirements for tools to be used for geometric measurement, mapping, metal loss, crack or other anomaly detection during their passage through pipelines. The tools may pass through the pipeline driven by the flow of a medium or may be towed by a vehicle or cable. The tools may be automatic and self-contained or may be operated from outside the pipeline via a data and power link.

This document has been reviewed and approved by the Pipeline Operator Forum (POF). It is stated however, that neither any of the member companies of the POF nor their representatives can be held responsible for the fitness for purpose, completeness, accuracy and/or application of this document.

A draft version of this document has been sent for comments to in-line-inspection Contractors as listed in Appendix 1. The POF like to thank the Contractors for their constructive feedback.

This document is intended to serve as a generic in-line-inspection specification and therefore cannot cover all pipeline or pipeline operator specific issues. POF members and other users of this specification are therefore free to add or change requirements that should be based on their specific pipeline situation. To support the pipeline operator in specifying/detailing optional items in this document, a guideline with a short description of these items is given in Appendix 2.

Comments on this specification and proposals for updates may be submitted to the Administrator at specifications@pipelineoperators.org with the form which is available on the POF website (www.pipelineoperators.org).

2 Definitions and abbreviations

2.1 General

During the update of this specification, reference to standards such as API 1163 [1] and PDAM[1] [2] have been reviewed and some terminology has been aligned. However, if referenced standards are in conflict with this (POF) specification, this specification prevails.

If the word "shall" is used in this document it indicates a requirement.

If the word "should" is used in this document it indicates a recommendation.

2.2 Definitions

Anomaly/feature definitions are provided in such manner that the ILI vendor can identify them accurately, e.g. general reporting like metal loss and deformation is not sufficiently detailed.

For the purpose of this document, the following definitions apply:

Above Ground Marker:	A device, on the outside of and close to a pipeline, that detects and records the passage of an ILI tool or transmits a signal that is detected and recorded by the tool. Reference magnets can be applied to serve identical purposes.
Anomaly:	An indication, detected by in-line inspection, of an irregularity or deviation from the norm in pipe material, weld material or coating, which may or may not be an actual flaw.
Arc strike [2]:	Localised point(s) of surface melting caused by arcing between a welding electrode or ground and the pipe surface. The defect formed is a surface depression which may be associated with a local increase in hardness.
Blister [2]:	A raised spot on the surface of the pipe caused by expansion of gas in a cavity within the pipe wall.
Buckle [2]:	A local geometric instability causing ovalisation and flattening of the pipe as a result of excessive bending or compression with possibly abrupt changes in the local curvature, which may or may not result in a loss of containment. *Note: Buckle to be defined in detail for reporting as Global, Local or Propagation, see below.*
Buckle arrestor:	A device or element in the pipeline with high wall thickness that will act to stop the advance of a propagating buckle.
Buckle, global or Global buckle [2]:	A Global Buckle will typically involve several pipe joints. It can be horizontal or vertical.
Buckle, local or Local buckle [2]:	A Local Buckle is a mode causing gross deformation of the pipe cross section, also known as pipe wall buckling. Collapse,

[1] PDAM is only used as a reference for definitions

localised wall wrinkling and kinking are examples of local buckling.

Buckle, propagation or Propagating Buckle [2]: A Propagating Buckle is the result of a dynamic process whereby a local buckle propagates along the length of the pipeline. A propagating buckle cannot initiate unless a local buckle has occurred.

Casing: A type of feature consisting of a larger diameter pipe placed concentrically around the pipeline, usually in high stress areas such as road crossings or otherwise protecting the pipe from mechanical damage.

Certainty: The probability that the characteristics of a reported anomaly are within the stated tolerances.

Characteristic [1]: A physical descriptor of a pipeline e.g. grade, wall thickness, manufacturing process or type, size, shape of an anomaly.

Client [1]: An organisation that owns and/or operates the pipeline facilities.

Cluster: Two or more adjacent anomalies in the wall of a pipeline or component of a pipeline that may interact to weaken the pipeline more than either would individually.

Colony [3]: A grouping of stress corrosion cracks (cluster) occurring in groups of a few to thousands of cracks within a relative confined area.

Combined features: Features that appear at the same location but at different (inner and outer) surfaces.

Component [1]: Any physical part of the pipeline, other than line pipe, including but not limited to valve, weld, tee, flange, fitting, tap, branch connection, outlet, support, anchor, above ground marker, anode, repair, additional metal and wall thickness change.

Contractor [1]: Any organisation providing ILI services to Clients.

Corrosion: An (electro)-chemical reaction causing loss of metal.

Corrosion Resistant Alloy (CRA): An alloy with increased corrosion resistance which may contain metals such as: chrome, cobalt, nickel, iron, titanium, molybdenum.

Corrosion related to CRA: Corrosion between carbon steel and CRA affecting the interface.

Crack: A planar, two-dimensional anomaly feature with a high length to width ratio, a sharp root radius and a possible displacement (surface opening) < 0.1 mm of the fracture surfaces.

Crack-like	An anomaly feature similar to a crack with some volume and a displacement (surface opening) between 0.1 and 1.0 mm of the fracture surfaces but that might not have a sharp root radius.
Debris:	Extraneous material in a pipeline.
Deformation:	A plastic change in shape in the steel pipeline. *Note: Deformations are to be reported as e.g. bend, dent, ripple/wrinkle, buckle or ovality, see below.*
Dent:	A local plastic or elastic deformation of the pipe wall resulting in a change of the internal diameter caused by an external force. *Note: Dents to be defined in more detail for reporting as Kinked, Plain or Complex*
Dent, Complex	A dent which causes a smooth change in curvature of the pipe wall that contains an anomaly (such as e.g. gouge, corrosion loss, crack) and/or is associated with an adjacent girth, spiral or seam weld.
Dent, Kinked [2]:	Dent with an abrupt change in the curvature of the pipe wall if any radius of curvature in the dent is ≤ 5 times the wall thickness. This type of dent might also be associated with wall thickness reduction or crack.
Dent, Plain [2]:	A dent which causes a smooth change in curvature of the pipe wall that contains no wall thickness reduction (such as gouge, crack, corrosion) and is not associated with an adjacent girth, spiral or seam weld.
Detection threshold:	Minimum detectable feature dimension at a certain certainty.
Feature:	Component or anomaly in a pipeline detected by in-line inspection.
Geodetic Datum	3D coordinate system. *Note: the World Geodetic System (WGS84) is commonly used, but others include ETRF89, NAD83, NAD27, RGF93 and more.*
Gouge:	A surface damage with elongated grooves or cavities caused by mechanically displaced or removed material from the pipe wall by interference with a foreign object.
Grinding:	Wall thickness reduction by removal of material by hand filing or power disk grinding.
Heat affected zone (HAZ):	The area around a weld where the metallurgy of the metal is altered by the rise in temperature caused by the welding process, but this is distinct from the weld itself. For the purpose of this specification it is considered to be within 2t with a minimum of 20mm.

In-Line Inspection (ILI):	Inspection of a pipeline from the interior of the pipe using an In-Line Inspection tool.
In-Line Inspection (ILI) tool:	Device or vehicle, also known as an intelligent or smart pig that uses a non-destructive testing technique to inspect the pipeline from the inside.
Interaction of anomalies:	Two or more adjacent anomalies in the wall of a pipeline or component of a pipeline that may interact to weaken the pipeline more than either would individually.
Joint:	Single section (also pipe spool) of pipe that is circumferentially welded to form a pipeline.
Lamination [2]:	Internal metal wall separation creating layers generally orientated parallel to the pipe wall.
Lap:	A flap of metal that has been rolled or otherwise worked against the surface of the metal but is not fixed, usually with a trapped residue of oxide or scale beneath it.
Mapping:	Recording of the 3D pipeline route using the inertial navigation system of the ILI tool.
Maximum allowable operating pressure [2]:	The maximum allowable operating pressure (MAOP) is a pressure less than or equal to the design pressure and represents the maximum allowed pressure during normal operation.
Metal loss [2]:	Any volumetric pipe anomaly in which metal has been removed. *Note: Metal loss to be reported as e.g. corrosion, gouging, grinding or mill anomaly*.
Measurement threshold:	The minimum dimension(s) of a feature to make sizing possible.
Mill anomaly:	An anomaly that arises during manufacture of a pipe joint or component. *Note: Mill anomalies to be reported as e.g. lap, sliver, lamination, non-metallic inclusion, grinding roll mark or arc strike*.
Ovality [2]:	Out-of-roundness of the pipe joint, defined in terms of the difference between the maximum and minimum internal diameter of the pipe joint.
Pinhole:	Localized corrosion with surface dimensions smaller than 1t or 10 mm whichever is greater in length and width direction.
Pipeline:	A system of joints and other components used for the transportation of products. A pipeline extends from launcher tool trap to receiver tool trap, including the tool traps, or, if no tool trap is fitted, to the first isolation valve within the

	plant boundaries or a more inward valve if so nominated and designed to a pipeline design code.
Pitting:	Localized corrosion of a metal surface that is confined to small areas and takes the form of cavities called pits, but are larger than pinholes. *Note: The dimensions of pitting are defined in detail further in this document.*
Probability of Detection:	The probability of detection is the probability that a specified feature will be detected by the ILI tool. *Note: The level of probability to be used is defined in detail further in this document.*
Probability of Identification:	The probability that a detected anomaly or feature will be correctly identified.
Processed raw data:	Data gathered from ILI tool sensors and passed through one or several filtering algorithms e.g. corrected for odometer slippage.
Raw data:	Unprocessed data from all sensors attached to the respective inspection tool during a pipeline inspection.
Reference magnet:	A permanent magnet placed on the pipeline with known location and/or coordinates used to correlate the inspection data. See also Above Ground Marker.
Reporting threshold:	A parameter, which defines whether or not an anomaly will be reported.
Ripple/Wrinkle:	A smooth local plastic, mainly circumferential orientated, deformation on the out and/or inside wall of the pipe caused by bending stresses. For a wrinkle, the peak-to-valley distance is greater than a ripple.
Roll mark [2]:	Markings on the pipe surface resulting from the plate or pipe rolling process used for spirally or longitudinally seam welded pipe.
Roof topping/peaking [2]:	Incorrect forming of the plate edges into the pipe curvature during fabrication, resulting in meeting of the edges as a triangular apex with the seam weld projecting beyond the circular contour of the pipe, also called peaking or angular misalignment.
Sizing accuracy:	Sizing accuracy is given by the interval with which a fixed percentage of features will be sized. This fixed percentage is stated as the certainty level.
Sliver [2]:	A thin elongated piece of metal rolled into the surface of the pipe, often metallurgically attached at one end. Sometimes reported as lap or lamination.

Strain	Geometrical, non-dimensional measure of deformation representing the relative displacement between particles in a material body.
Trap, launcher/receiver:	An ancillary item of pipeline equipment, with associated pipe work and valves, for introducing an ILI tool into a pipeline (launcher trap) or removing an ILI tool from a pipeline (receiver trap).
Wall thickness, Measured:	The average of measured, un-corroded wall thickness values that is representative for a whole pipe joint/component.
Wall thickness, Nominal:	The wall thickness required by the specification for the manufacture of the pipe.
Wall thickness, Reference:	The actual undiminished wall thickness surrounding a feature, used as reference for the determination of the feature depth.
Weld:	The area where joining has been realised by welding. This is distinct from the heat-affected zone, but is located within it.
Weld anomaly:	Anomaly in the body or the heat affected zone of a weld.
Weld affected area:	Area on both sides of a weld where ILI measurements are affected by the geometry of the weld. See also "Heat affected zone".

2.3 Abbreviations

For the purpose of this document, the following acronyms apply:

A	A geometrical parameter used to specify the dimension class of metal loss anomalies detected by in-line inspection of a pipeline and further defined in Figure 2.1 of this document.
AGM	Above Ground Marker
CRA	Corrosion Resistant Alloy
d	Depth of metal loss
E	End point of anomaly
EC	Eddy Current
EMAT	Electro Magnetic Acoustic Transducer
ERF	Estimated Repair Factor
GIS	Geographic Information System
GNSS	Global Navigation Satellite System
GPS	Global Positioning System
h	Height or depth of Wrinkle/Ripple/Dent or Roof topping
HAZ	Heat Affected Zone

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ILI	In-Line Inspection
IMU	Inertial Mapping Unit
ID	Internal pipe Diameter
l	Length of anomaly/feature dimension in the axial direction and length of cracks in any direction
MAOP	Maximum Allowable Operating Pressure
MOP	Maximum Operating Pressure
MFL	Magnetic Flux Leakage
NDE/NDT	Non-Destructive Examination/Non-Destructive Testing
OD	Outer pipe Diameter
PDAM	Pipeline Defect Assessment Manual
POD	Probability Of Detection
POI	Probability Of Identification
P_{safe}	Safe operation pressure as per calculated defect assessment method
R	Internal pipe Radius
S	Start point of anomaly
SCC	Stress Corrosion Cracking
t	Wall thickness
UT	Ultrasonic Testing
w	Width of anomaly/feature in the circumferential direction and opening dimension for crack-like features
WGS 84	World Geodetic System 1984

2.4 Parameters and interaction of anomalies

2.4.1 Metal loss

The parameters of anomalies are length "l", width "w" and depth "d". The starting point, S, and the dimension of an anomaly are defined as illustrated in *Figure 2.1* looking in the ILI run direction. Start and end points are diagonally in a rectangle enclosing the anomaly. The depth represents the deepest point reported within the rectangle.

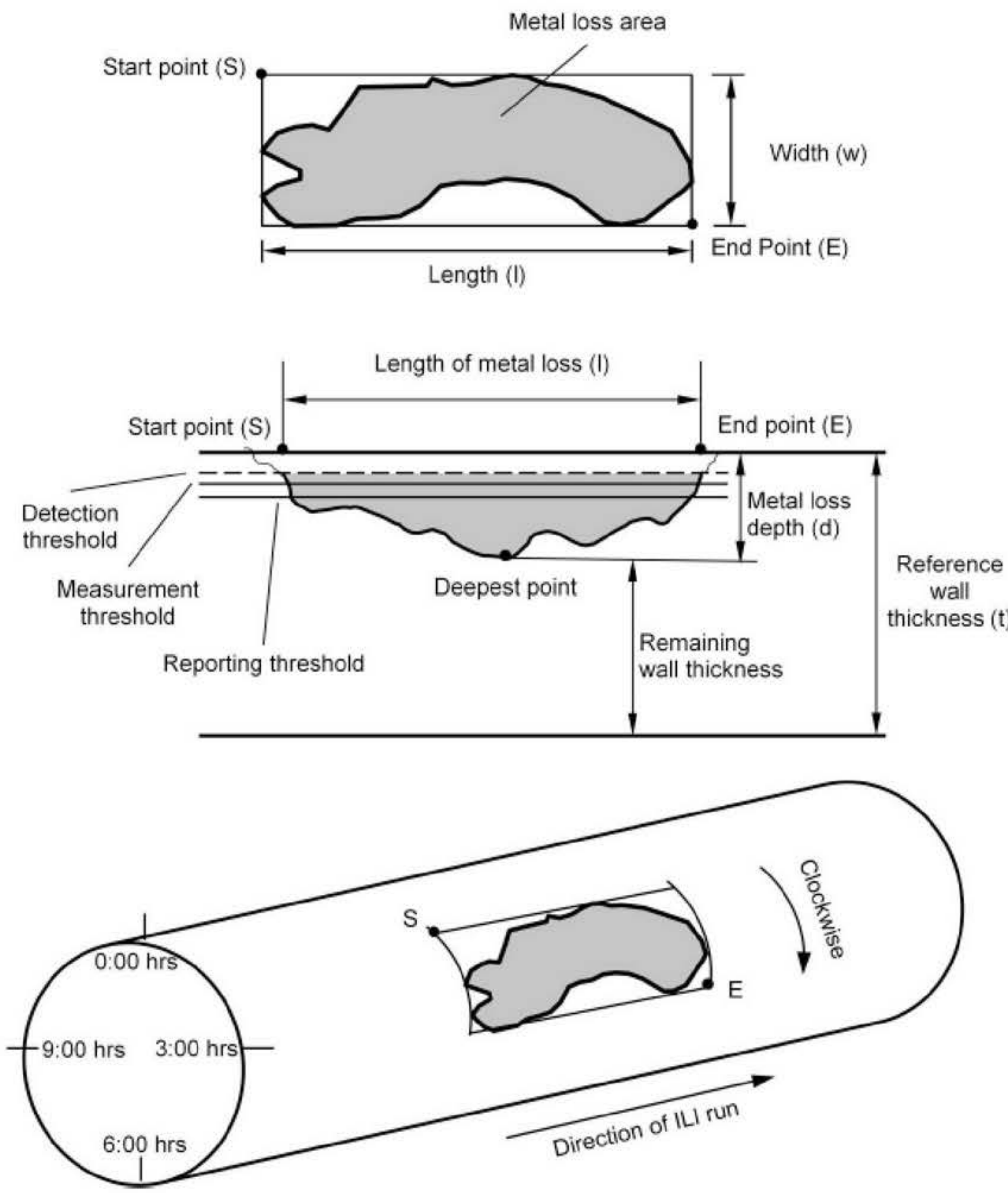


Figure 2.1: Illustration of parameters describing location and dimension of metal loss feature.

The start position of the anomaly has a lower clock position than the end position. Anomalies crossing the 0:00 o'clock position have a higher clock position at the start. Full circumferential anomalies are reported with S at 0:00 o'clock. *Note: highest clock position shall be 11:59.*

Metal loss anomaly classification

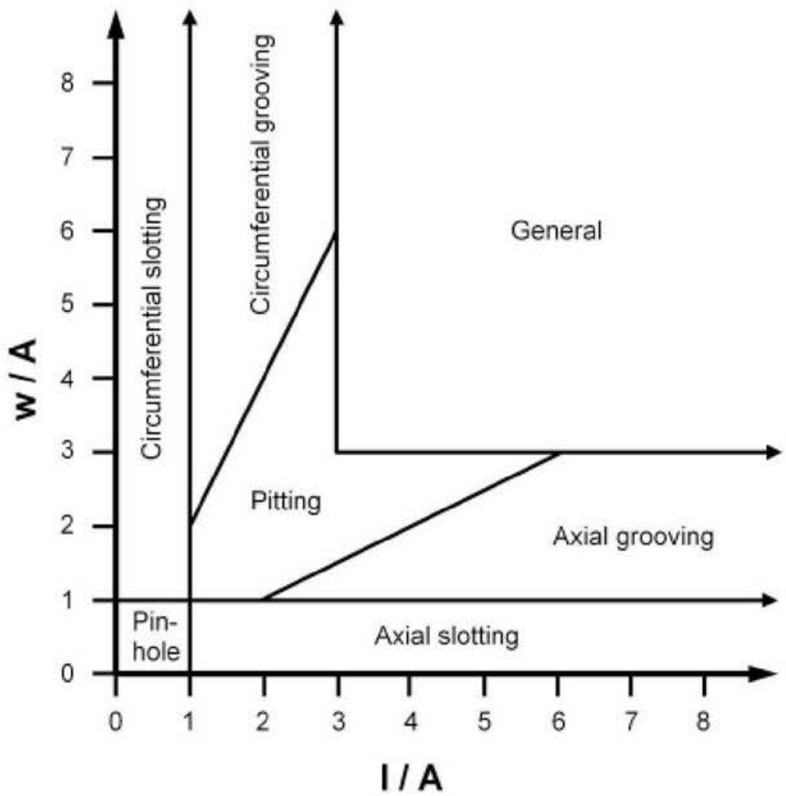
The measurement capabilities of non-destructive examination techniques, in particular the MFL technique, depend on the geometry of the metal loss anomalies. Metal loss anomaly classes have been defined as shown in Figure 2.2 for anomaly reporting purposes. In addition it allows for a proper specification of the measurement capabilities of MFL ILI tools.

Each anomaly class permits a large range of shapes. Within that shape a reference point/size is defined at which the POD for MFL tools is specified, see Table 2.1. An even distribution of length, width and depth shall be assumed for each anomaly dimension class to derive a statistical measurement performance on sizing accuracy.

Table 2.1: Definition of anomaly dimension class and MFL POD reference point/size

Anomaly dimension class	Definition	Reference point/size for the POD in terms of l x w
General:	{[w ≥ 3A] and [l ≥ 3A]}	4A x 4A
Pitting:	{([1A ≤ w < 6A] and [1A ≤ l < 6A] and [0.5 < l/w < 2]) and not ([w ≥ 3A] and [l ≥ 3A])}	2A x 2A
Axial grooving:	{[1A ≤ w < 3A] and [l/w ≥ 2]}	4A x 2A
Circumferential grooving:	{[l/w ≤ 0.5] and [1A ≤ l < 3A]}	2A x 4A
Pinhole:	{[0 mm < w < 1A] and [0 mm < l < 1A}	Minimum dimensions to be further defined by Contractor, see table A3-2
Axial slotting*:	{[0 mm < w < 1A] and [l ≥ 1A]}	2A x ½A
Circumferential slotting*:	{[w ≥ 1A] and [0 mm < l < 1A]}	½A x 2A

* Anomalies with a width < 1mm are defined as crack of crack-like which might or might not be metal loss



The geometrical parameter A is linked to the NDE methods in the following manner:

- If t < 10 mm then A = 10 mm
- If t ≥ 10 mm then A = t

Figure 2.2: Graphical presentation of surface dimensions of metal loss anomalies per dimension class.

2.4.2 Dent

A dent is defined by its type (Kinked, Plain, Smooth), maximum depth (h), width and length, as shown in Figure 2.3. If requested, the maximum strain based on a methodology agreed between Client and Contractor. If the dent results in an ovality of the pipe then a more detailed description and evaluation is required.

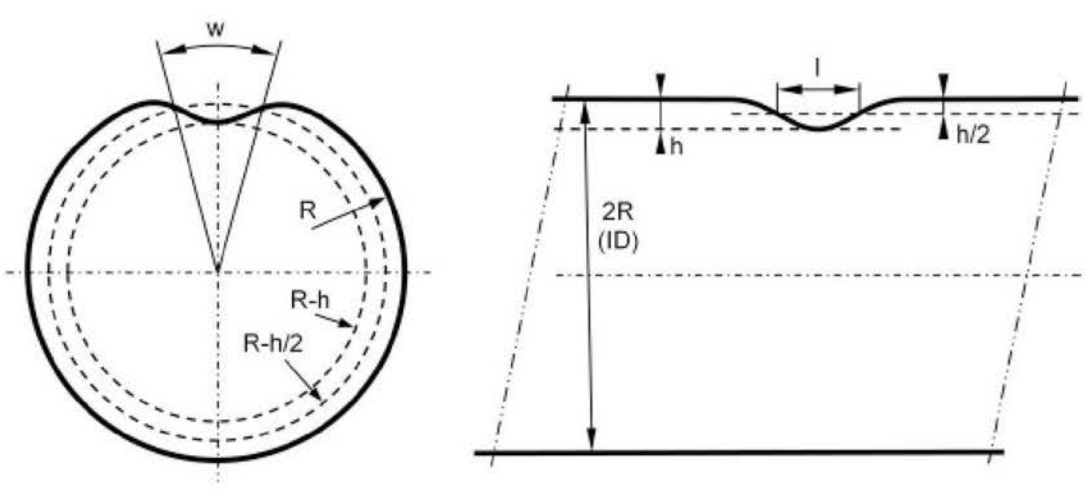


Figure 2.3: Measurement of dent.

The dent is defined as a percentage of the OD where h is measured from either the inside or outside of the pipe:

$$\frac{h}{OD} * 100\%$$

2.4.3 Gouge

As a gouge can take various forms, a schematic drawing is not available. Gouge anomaly dimensions are defined by the rectangle as shown in Figure 2.1, but the Contractor shall classify them as gouges with the angle related to the pipe axis reported as well. If a gouge is associated with a dent, then it shall be reported as a "Smooth or Kinked Dent with Gouge" with separate dimensions of the gouge and dent.

2.4.4 Ovality

Ovality is specified by ID_{max} and ID_{min} as shown in Figure 2.4

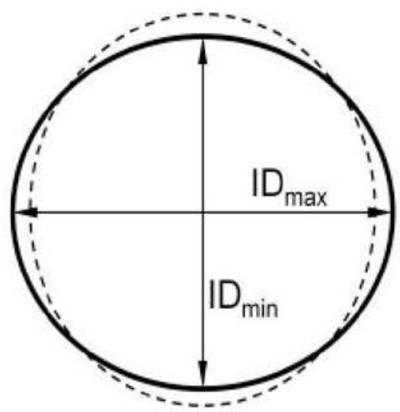


Figure 2.4: Measurement of ovality at one point over distance.

The ovality is defined as the ratio given in the equation below:

$$\frac{ID_{max} - ID_{min}}{\left[\frac{ID_{max}+ID_{min}}{2}\right]}$$

The ovality reported at the joint is based on a statistical approach of the measurements along the joint. It can be the mean ovality or any percentile (90th is common) or the maximum measured, which is to be detailed by the Client in the contract. If not specified otherwise, the maximum shall be reported. *Note: Reporting of ovality dimensions depends on the used formula (code) and it is therefore required that the formula applied is stated in the report.*

2.4.5 Buckle

As a buckle can take various forms, a schematic drawing is not available.

2.4.6 Ripple/Wrinkle

A ripple/wrinkle is specified by its height and length as shown in Figure 2.5Figure 2.5, Figure 2.6 and Figure 2.7. The maximum values shall be reported and, if requested, also the maximum strain based on a methodology agreed between Client and Contractor.

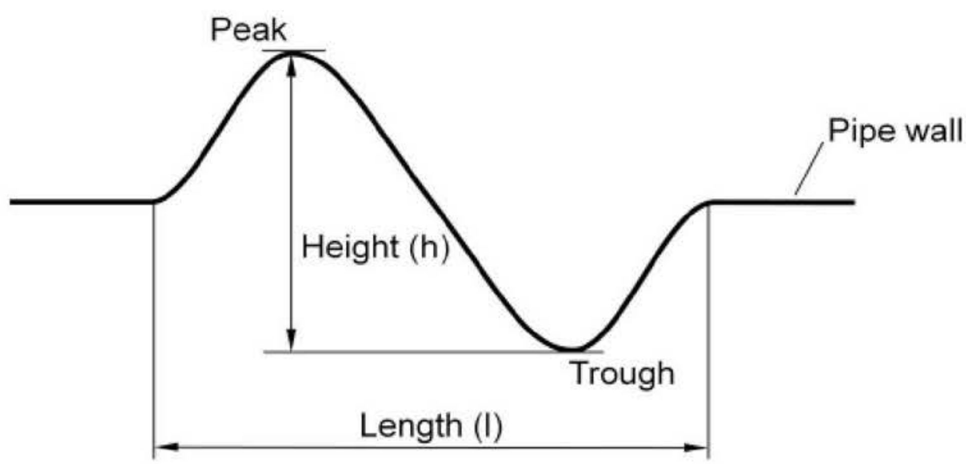


Figure 2.5: Measurement of ripple / wrinkle.

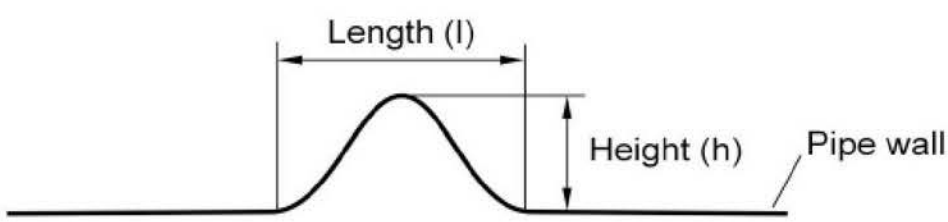


Figure 2.6: Measurement of single ripple/wrinkle.

A ripple/wrinkle is defined by its length (l) and maximum height (h).

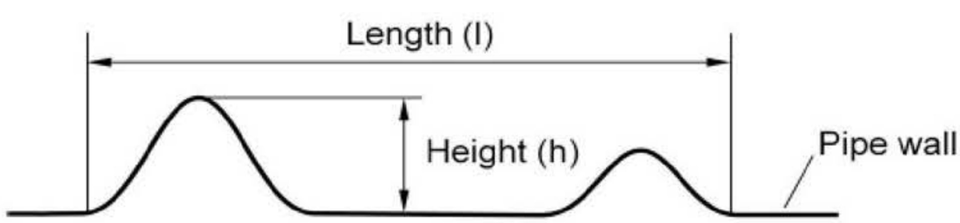


Figure 2.7: Measurement of multiple ripple / wrinkle.

Multiple ripples/wrinkles are defined by the total length (l) and maximum height (h).

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2.4.7 Roof topping/peaking

Roof topping/peaking is specified by the angle 2Θ and height (h), see Figure 2.8.

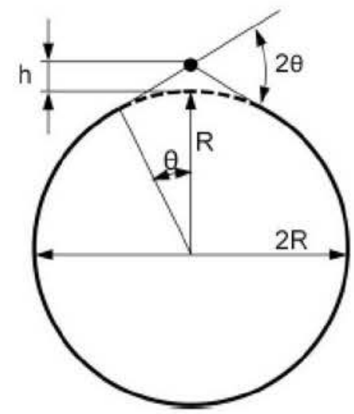

Figure 2.8: Measurement of peaking/roof topping.

Roof topping/peaking is defined by its height h in mm and angle 2Θ in degrees (°).

2.4.8 Crack and crack-like

A crack or crack-like feature is specified by the length (l, from tip S to tip E), depth (d) and orientation (angle α) to the pipeline axis, see Figure 2.9.

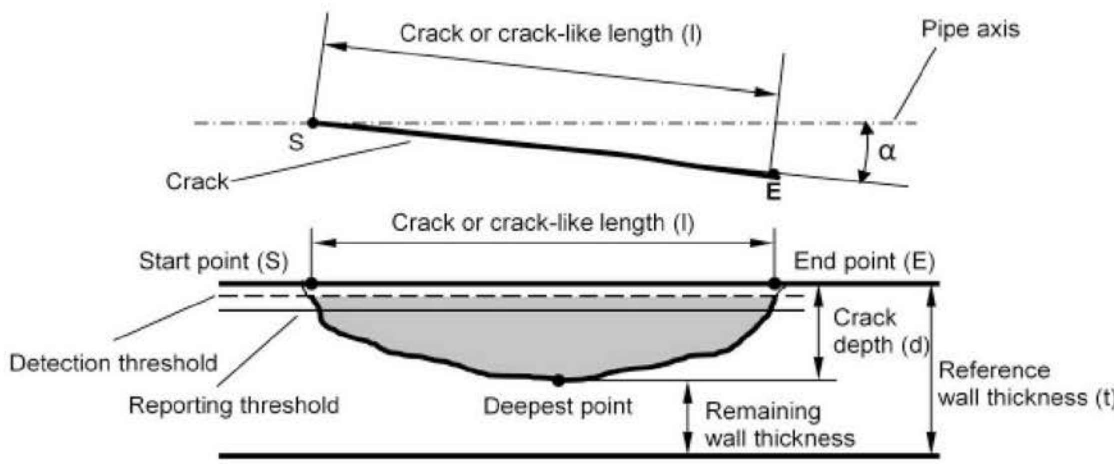

Figure 2.9: Illustration (top view and cross section) of parameters describing location and dimension of crack and crack-like features.

Planar, two-dimensional and elongated pipeline features mechanically splitting the pipe wall into two parts and oriented primarily perpendicular to the pipe surface are referred to as cracks or crack-like anomalies depending on the driving cracking mechanism.

Cracks are typically oriented either axially in the pipe body, or in the longitudinal, spiral, or circumferential weld areas and welds. Independent from the nature of the cracking mechanism, cracks in pipelines are observed as single or colonies.

The parameters of single crack and crack-like anomalies are length "l" and depth "d". Due to its planar, two-dimensional nature a crack or crack-like anomaly shows no width but may show a crack opening depending on the geometry and nature of the crack.

Cracks are regarded to have an opening at the surface < 0.1 mm, crack like defects to have an opening at the surface of 0.1 mm to 1.0 mm.

The capabilities of non-destructive examination techniques to detect, classify and size crack and crack-like anomalies strongly depend on the technology itself and its implementation on the inspection tool. In contrast to metal loss anomalies, no anomaly classes exist for cracks and crack-like anomalies. The Contractor shall provide the tool performance specifications in accordance to section 4.4 and table A5-4 with special emphasis on:

- The POD at 90% as a function of the anomaly dimensions.
- Details on the basis of the performance shall be clearly presented with regards to artificial and/or natural features.

2.4.9 Crack colonies

A crack colony is specified by the length (l), width (w), see Figure 2.10 and depth of the deepest single crack in the colony (see Figure 2.9).

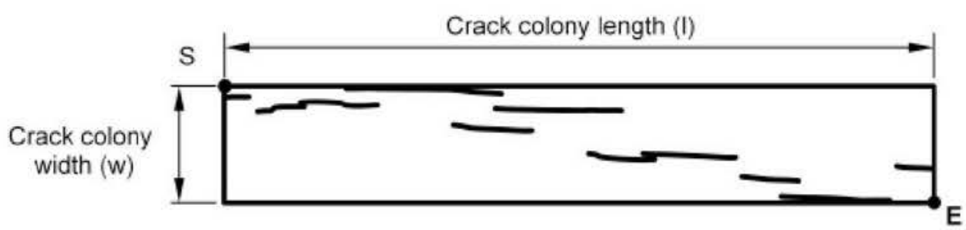

Figure 2.10: Illustration (top view) of parameters describing location and dimensions of crack colonies.

Colonies of cracks can be formed as a result of corrosion (e.g. SCC) and cracks in such a colony might interact depending on their dimensions, separation and density. Interaction rules are applicable for assessment, see 2.6.1.

2.5 Nomenclature of features

Features can be divided into component features and anomaly features.

Features shall be identified in accordance with Appendix 3: Report structure, terminology and abbreviations: Column Feature type.

The type of features shall be further identified in accordance with Appendix 3: Report structure, terminology and abbreviations: Column Feature identification.

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2.6 Anomaly assessment

2.6.1 Interaction rules

Clustering of anomalies will be required if defects can interact and thereby pose a greater risk to the pipeline than individually assessed. The applicable assessment method shall define the interaction rules and clustering requirement.

If not specified otherwise by the Client, the latest version of ASME B31G [11] should be used for assessment and interaction rules of metal loss. Possible alternative methods include, but are not limited to:

- API 579/ASME FFS (general, including metal loss and cracking) [9]
- Modified ASME B31 G, (metal loss) [11]
- BS 7910 (general, including metal loss and cracking) [10]
- DNV RP-F101 (metal loss) [12]
- Kastner (only circumferential features) [8]
- CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion Cracking (only SCC) [3]
- Pipeline Defect Assessment Manual (PDAM) [2].

2.6.2 Indication of anomaly severity (ERF)

To allow the Client to rank the indications of anomalies in the pipeline on the basis of a first pass screening of severity, the Estimated Repair Factor (ERF) can be used. It is noted that for significantly ranked defects a more sophisticated assessment may then be applied.

The ERF is defined as:

$$ERF = MAOP/P_{safe}$$

P_{safe} is the safe working pressure as calculated by the latest version of an appropriate anomaly assessment method as agreed between Client and Contractor. P_{safe} shall be calculated using specific information of the pipeline segment such as the measured wall thickness and appropriate design factor for the area class.

If not specified otherwise by the Client, the latest version of ASME B31G [11] should be used for metal loss features. For possible alternative assessment methods (but not limited to) see section 2.6.1.

Note: The calculation of ERF has been updated from previous versions of this POF specification by replacing MOP with the MAOP. Whereas MOP could be applied as a temporary process restriction, MAOP implies the maximum pressure that could be introduced to the pipeline both at the time of the calculation and for any future operations.

2.7 Resolution of measurement parameters

A list of definitions with resolution and associated units to be used is presented in Table 2.2.

Table 2.2: List of definitions with minimum resolution and associated units to be used.

Definition	SI/metric units	Alternative units
Log distances	0.001 m	0.01 ft
Feature length and width	1 mm	0.01 inch
Feature depth	0.1 mm or 1%	0.01"or 1%
Reference t	0.1 mm or 1%	0.01" or 1%
Orientation	0.5° or 1 minute	1 minute
ERF	0.01	0.01
Magnetic field strength (H)	0.1 kA/m	1 Oe (Oersted)
Magnetic flux density (B)	0.1 T (Tesla)	10^{3} G (Gauss)
Axial sampling distance	0.1 mm	0.01 inch
Circumferential sensor spacing	0.1 mm	0.01 inch
Tool speed	0.1 m/s	0.1 ft/sec
Temperature	1 °C	1 °F
Pressure	0.01 MPa/0.1 bar	1 psi
Global Position Coordinates[1)]	0.01 m	10^{-8} ° (Decimal degree)

1) Unless specified otherwise, WGS84 shall be used as the coordinate system

3 Health and safety

Care for health and safety is essential during any stage of any activity. As ILI of pipelines typically involves working with pressurized components and potentially explosive, flammable or hazardous atmosphere, adequate procedures must be in place to prevent any harm to personnel, environment or equipment. It is the responsibility of both Client and Contractor to agree on health and safety requirements and procedures and to check if latest and most stringent versions of (local) HSE requirements are met.

ILI operations require a pipeline to be opened and an inspection tool to be loaded/unloaded whereby explosive environments might occur. Special measures to prevent unsafe situations during ILI activities shall be taken.

Regulations have been developed to prevent accidents due to explosive environments. Examples of these regulations are the ATEX guidelines (ATmosphères EXplosive) which is mandatory for activities in the European Union or the IECEx system (*International Electro technical Commission: IEC System for Certification to Standards relating to equipment for use in Explosive Atmospheres*).

Implementation of ATEX, IECEx or an equivalent directive might be mandatory on the basis of national, local legislation or Client policy and if required shall be employed for ILI operations in addition to already applicable standards and procedures.

For use of non-electrical equipment in potentially explosives atmospheres, EN 13463 or an equivalent standard can be applicable.

For use of electrical equipment in potentially explosives atmospheres, EN-IEC 60079-xx (-10, -14, -17) or an equivalent standard can be applicable.

3.1 ATEX

ATEX zone 1 is considered to be applicable for ILI operations. The Client shall specify if ATEX certification is required and if so, the following two directives shall be followed:

- ATEX 114[2], Directive 2014/34/EU of the European Parliament and of the Council of 26 February 2014 on the harmonization of the laws of the Member States relating to equipment and protective systems intended for use in potentially explosive atmospheres.

  For ILI activities in the oil and gas industry it is considered that, unless specific measures are taken, zone 1 (areas with occasional dangerous explosive atmosphere caused by gas, vapour or mist) is typically applicable. Unless the Client specifies otherwise, the ATEX certified ILI tool shall comply with:
  - Group II: Equipment intended for use in explosive atmospheres other than mines
  - Category 2: High protection level for use in zone 1
  - Minimum temperature class T3: Surface temperature of equipment < 200°C (depending on the medium, another temperature class might be required e.g. T4 (<135°C).

  Note: This directive implies that the Contractor has to assess all potential explosion risks of its equipment and has to design the equipment to this directive.

- ATEX 153[2], Organizational requirements for health & safety protection of industrial workers at risk from potentially explosive atmospheres.

[2] Latest or superseding versions of the relevant codes shall be used

ATEX 153 gives organizational and operational requirements for activities in potentially explosive environments. Client and Contractor are to define the operating procedures and work instructions to assure safe work environment. Client is in lead and stays responsible. The operating procedures are considered outside the scope of this document.

Note: This directive requires that the Client assess the zoning of the launch/receive trap workspace through risk assessment and that Client is responsible for ensuring that all equipment introduced into these zones is compliant and QA certified against ATEX 114.

In addition to the ATEX requirements, which are only valid for atmospheric conditions, the Client shall specify, whether the contractor shall ensure safe operation of ILI equipment under explosive conditions for pressures > .11 MPa during receiving and launching of tools.

3.2 IECEx

The IECEx is an alternative code for certification of ILI equipment with equal area of application as ATEX 114, but not further discussed in this specification.

4 Tool specifications

4.1 Introduction

Tool specifications are important for the Client to clearly understand the capabilities and limitations of an ILI tool before selection and use. The purpose of this section is to present a consistent approach for presenting tool specifications and agreed tool specifications shall be part of the contract between Client and Contractor, as further described in chapter 6. Tool specifications typically consist of the combination of tool data sheets and tool performance specification:

- Tool data sheets cover the physical dimensions of the tool and operating conditions the tool can work in
- Performance specifications describe the inspection capabilities and limitations of the inspection technology applied. Tool performance follows the general requirements of API 1163 supported by Contractor quality systems.

The Client should clearly define the goals and objectives of an ILI before tool selection can take place. A key aspect in this process is a proper identification of pipeline threats and anticipated degradation mechanisms. The expected type, size, location and orientation of anomalies are important inputs to tool selection. In many cases tool selection requires a deeper understanding and details of specific tools which can best be obtained in a discussion between Client and Contractor. Factors that may influence tool performance, such as level of cleanliness and pipeline operating conditions need to be considered as well.

Prior to an in-line inspection the following should be in place:

- The Client to communicate the goal and objectives of the ILI to the Contractor
- Tool selection to be discussed and agreed between Client and Contractor
- Contractor to confirm that tool selection is appropriate given the goals and objectives of the ILI.

4.2 Tool data sheets

Tool data sheets provide information to allow Client to understand the limitations of service and suitability for use in pipeline system. Typically separate tool data sheets exist for each diameter and inspection technology combination.

They shall clearly present:

- Tool identification
- Tool specifications
- Safety
- Operating conditions/parameters
- Pipeline restrictions
- Launcher and Receiver trap details.

Detailed tool data sheet requirements are included in Appendix 4.

4.3 Tool class history

In order to achieve a high probability of first run success (Ref. POF document "Guidance on achieving ILI First Run Success" [5]), it is important that the Client clearly understands the operating history of the tool class and its level of operational testing. Before the ILI contract is confirmed and unless otherwise agreed, Client may request any or all of the following information:

- Technology readiness of tool class hardware for operating conditions using the following grades:
  1. Newly designed component with limited testing
  2. Limited field operation (< 20 runs or < 500 km distance)
  3. Multiple uses with clear history of components and subsequent changes
- Provide a unique tool reference number and applicable data sheet.

Design changes to tool components or modules that may affect level of readiness shall be clearly communicated to Client both at time of placing order and for any subsequent change made by Contractor.

4.4 Tool performance specification

Tool performance specifications shall define the ability of the ILI system to detect, locate, identify, and size pipeline features, components and anomalies. It is typically linked to the inspection technology applied in the tool (e.g. UT, MFL, EC, EMAT or mapping).

4.4.1 General

Tool performance specifications shall comply with requirements given in API 1163 [1], chapter 6. The following general requirements are given for tool performance specifications:

- The Probability Of Detection, POD (a), is the probability that a feature with size a will be detected by the ILI tool. Two feature sizes are frequently extracted from the POD information: $a_{90/50}$ (a_{90}) is the feature size at which the average POD is 90% and $a_{90/95}$ is the feature size at which the lower 95% confidence limit of the POD is 90%, see also Figure 4.1. In the tool performance specification it shall be clearly specified what POD value is given. It is recommended to specify the $POD_{90/95}$ value
- The Probability of Identification, POI, is the probability that a feature is correctly identified by the ILI tool. The type or types of anomalies, components, and characteristics that are to be detected, identified, and sized by the ILI system shall be clearly indicated. Identification of each feature type shall be reported as specified in Appendix 5, Table A5-1
- The measurement specifications for detection and sizing of the various anomalies and pipeline location shall be reported as specified in Appendix 5, Tables A5-2 to A5-8 where they apply. The Client might request to complete the alternative Table A5-3a in favour of Tables A5-2 and A5-3
- Performance specification shall clearly state the level of analysis that is required to support the level of specification
- Where a higher level of performance is based on more detailed analysis, the additional performance level and commercial basis for additional analysis shall be clearly stated and agreed by Client and Contractor
- If different technologies (e.g. MFL, UT, EC or EMAT) are combined into one tool, then the specifications shall be provided as if the technologies were applied in a separate tool and additionally a table with the specifications of the multi-technology tool shall be provided.

The performance specification shall define and document the essential variables. In general two types of essential variables should be considered for ILI tool performance: i) pipeline design and operational characteristics, ii) inspection tool design and physical characteristics. More detailed requirements on the essential variables are to be included in the performance specifications as listed in Appendix 5.

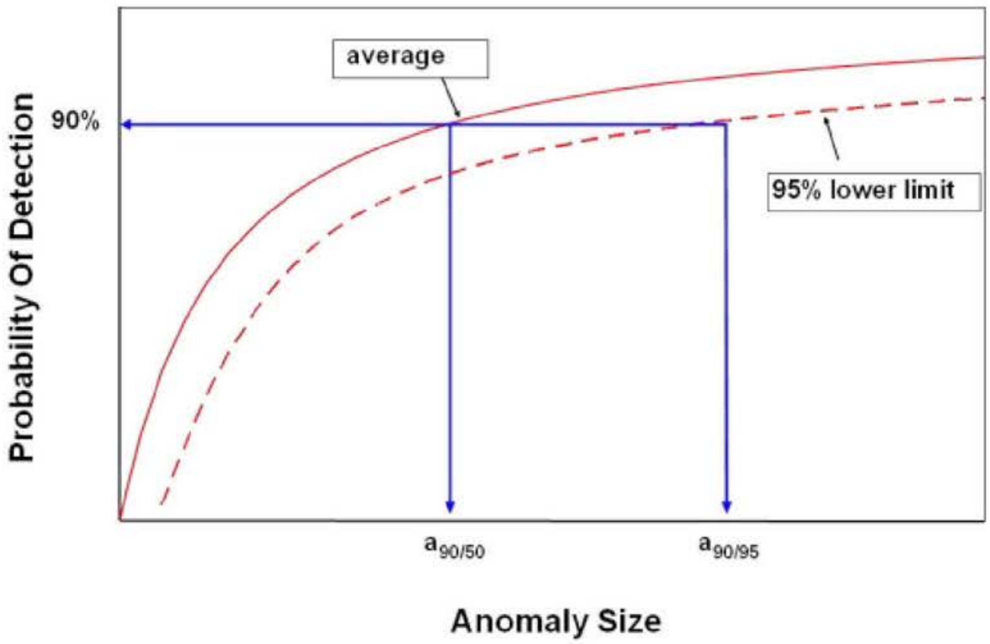

Figure 4.1: Typical example of the average and lower limit POD curve as function of anomaly size with indication of the definitions of $a_{90/50}$ (a_{90}) and $a_{90/95}$

4.4.2 Basis of performance

The basis on which performance specification is made shall be clearly stated for each feature type using the following:

- Modelling only
- Limited pull through tests and modelling (where effects of essential variables have not been fully tested by pull through runs and features used are predominantly manufactured)
- Extensive pull through tests covering range of speed and wall thickness using a combination of manufactured and natural features
- Limited field verification with less than 20 operational runs
- Extensive field verification results reviewed on an annual basis.

Where multiple methods are used, the Contractor shall clarify what has been used. Details of manufactured and/or natural features shall be clearly presented.

4.4.3 Exclusions and limitations

Physical and operational factors or conditions that limit the detection thresholds, PODs, POIs, and sizing accuracies shall be identified in the performance specification. It shall be clearly stated what the acceptable limits are for, but not limited to, e.g. tool speed and pipe wall thickness, see also Appendix 5.

4.4.4 Access to supporting performance information

Contractor shall provide access to information in support of stated tool performance specification on request of Client.

The ILI tool testing information of the contractor shall be auditable and contain information regarding the calibration procedure and latest calibration record of the tool. The procedure should give insight in, but not limited to: used calibration features, line pipe material, wall thickness and manufacturing process, tool velocity, date and frequency of calibration. For magnetic tools the calibration information will include the tool speed and the measured magnetic field strength value with the position where it was measured. In addition the Contractor shall supply a definition of which sizing model and revision was used.

How and where the information is to be provided is to be agreed between Contractor and Client. It is the responsibility of the Contractor to check that the tool and the calibration methods are valid and adapted to the Client's objectives.

4.5 Tool performance verification

A Client may choose to verify tool performance through formal testing or field verification.

In case formal testing is carried out, the report should at least contain the following information:

- Details of runs and essential variables tested
- Details of features
- Comparison of stated performance with actual reported features.

Regarding field verification more guidance can be found in POF document "Guidance on Field Verification Procedures for In-Line-Inspection" and API 1163 [1] (chapter 8 and Annex C). In case field verification is performed the following requirements apply:

- To ensure meaningful data is collected from the field, Client should facilitate access for Contractor to verify field measurement
- Client shall provide Contractor with field verification data (dig data)
- Contractor shall use field verification data to confirm tool performance.

4.6 Changes to tool specification or performance specification sheets

Changes to tool and performance specifications shall be tracked in Contractor Quality Assurance system. Each revision shall have date and issue number.

Where a change could affect earlier pipeline integrity assessment, Client shall be notified of change and potential implications. This typically applies when performance specification for certain features is reduced based on new information or additional testing. Any requirement for reassessment of features as a result of change shall be agreed between Client and Contractor.

5 Personnel qualification

The personnel operating the ILI systems and the personnel handling, analyzing and reporting the inspection results shall be qualified and certified according to ANSI/ASNT-ILI-PQ-2005 (reapproved 2010) [4] or later version/superseding document.

Unless the Client specifies otherwise, key personnel shall meet the following minimum qualifications, ref. ANSI/ASNT-ILI-PQ-2005 [4]:

- Team leader during ILI field activities: Level II Tool Operator for the applicable technology
- Data analysis and reporting Lead: Level II Data Analyst for the applicable technology
- Review of final Client report: Level III Data Analyst for the applicable technology. The review should include (but not limited to) e.g. a quality check of data analysis and reported results.

An overview of personnel qualifications that will be deployed for the ILI tool run, data analysis and final report review shall be submitted to the Client. The personnel qualifications shall be auditable.

6 ILI preparation and contracting

6.1 ILI preparation

The POF document "Guidance on achieving ILI First Run Success" [4] stresses the importance of the preparation and contracting phases to meet all the objectives of the inspection. The preparation phase is described in length in this document, which includes some check lists in Appendix B.

6.2 Contracting

This POF document is intended to serve as a generic ILI specification where details and deviations for ILI runs still need to be defined to serve Client's specific issues. Such details and deviations (Appendix 2 provides guidance), should be agreed between Client and Contractor and stated in the ILI contract.

The contract between the Client and the Contractor shall, as a minimum include the following items:

- Organization: The organization shall be defined between Client and Contractor, in terms of human and materials resources, communication, schedule of the operations, run conditions, procedures, roles and responsibilities, actions in the event of an emergency etc. The POF document "In-Line-Inspection Check Lists" [6] provides guidance
- Specific details: Details and deviations from the POF document "Specifications and requirements for in-line inspection of pipelines" (this document, if applicable)
- Run preparation: The Client should supply the Contractor with details of the pipeline(s) to be inspected. The POF document "ILI Pipeline Questionnaire" [7] provides guidance
- Operations: The operations shall be defined in terms of pipeline technical data, tool specifications, characteristics and performances, criteria for cleaning and run validation
- Results: The results shall be reported as per chapter 7. If requested by the Client, a revised version of the final report shall be issued in case of proven discrepancies between reported information and verifications.

The requirements herein may be changed at Client's request. Some points may depend on the configuration of the network to be inspected, the Contractor, the technology used, the internal (Client) policies and practices and local regulations.

It can be considered that, for specific applications, specifications and/or defect geometries, dedicated tool calibration can be performed (e.g. with spare project pipes), followed by a modified interpretation/sizing model.

7 Reporting

Reporting is an essential part of the inspection process and depending on the time and information required by the Client, various types of reports can be issued, see below. If the Contractor finds an anomaly during the inspection and/or evaluation of the ILI data which could be an immediate threat to the integrity of the pipeline, he has the duty to report this to the Client without delay.

If not agreed otherwise between Client and Contractor, reporting is based on at least two separate documents:

- Operations report
- Final report.

In addition to the above mentioned reports, one or more of the following reports can be requested and agreed between Client and Contractor:

- Preliminary report
- Raw data report
- Multiple run comparison report
- Additional reporting.

All documents and all lists (e.g. pipe tally, list of anomalies, etc.) will contain the following general information:

- Identification of the Contractor and Client
- Identification of the pipeline
- Product
- Outside or nominal diameter
- Length
- Construction year
- ILI technology/technologies
- Inspection date/Reference.

7.1 Operations report

The operations report should summarize important operational information such that the Client is informed on the success of the inspection and quality of data collected and should include information on run preparation, running of tool, run quality including pipeline cleanliness to verify if targets are achieved. If data quality is not as required for a successful pipeline feature evaluation, a re-run (if possible) can be considered. This report follows good practices regarding ILI activities as described in the POF document "Guidance on achieving ILI First Run Success" [5].

The operations report shall be sent in electronic form to the Client before demobilization of the tool and ultimately within 2 days of the ILI run, unless agreed otherwise. The demobilization of tool and crew shall be agreed between Client and Contractor based on the operations report results using the criteria below.

The operations report shall contain, unless agreed otherwise:

- Any reported safety observation (e.g. near miss)
- A description of the operations (cleaning, gauging, dummy tool run, ILI tool run) including run conditions

- Used tool(s) identification (serial number) with tool(s) data sheet and calibration
- AGM statistics (if applicable)
- Cleaning results and comparison to criteria
- Gauging/dummy tool run results and comparison to criteria
- Details of ILI run(s):
  - Time and date of tool launching and receiving
  - Travelling time
  - Min/max tool velocity, and tool velocity plot over the length of the pipeline
  - Min/max pressure
  - For MFL tools: min/max magnetization level, and a plot of the magnetic field strength in kA/m over the length of the pipeline measured at the inner surface of the pipe
  - Condition of tool(s) after receipt e.g. damaged sensors
  - Data loss statistics from faulty sensors and in case of UT echo loss statistics
  - Data recording and quality within contract specifications
- The suitability of the recorded data to allow a successful evaluation.

,The formulation for acceptable data loss shall be, unless specified otherwise:

- Continuous loss of data less or equal to 0.5 % of pipeline length
- Discontinuous loss of data less or equal to 3% of pipeline length
- Continuous loss of data from less than 4 adjacent sensors or 25 mm circumference (whichever is smallest).
- The criteria apply to each section of the pipeline i.e. each diameter, wall thickness and pipe manufacturing process.
- If data loss exceeds one of the criteria above, this shall be discussed between Client and Contractor to reveal the cause and decide on follow-up actions which might be:
  - A re-run of the tool
  - Check if the data loss has an effect on anomaly detection and sizing capability of the ILI tool.

The tool operational data statement shall indicate whether the tool has performed according to specifications and shall detail all locations of data loss and where the measurement specifications are not met. When the specifications are not met (e.g. due to speed excursions, sensor/data loss), the number and total length of the sections shall be reported with possible changes of accuracies and certainties of the reported results.

7.2 Preliminary report

A preliminary report is a list of features, including by their dig sheets. The reporting format is as per the list of anomalies in the final report. The preliminary report shall be delivered if requested by the Client or if the Contractor finds an anomaly (or anomalies) during the analysis of the ILI data which might be (are) an integrity threat to the pipeline.

The preliminary report aims at summarizing the most important features (individual and clustered) based on Client criteria as defined in the contract, in order to guarantee a safe pipeline operation. Unless agreed otherwise, typical reporting should include:

- Features with an ERF ≥ 0.8
- Metal loss features ≥ 50%

- Dents, Wrinkles/Buckles ≥5%
- Cracks with depth ≥ 4.0 mm.

Actual data quality shall be confirmed in terms of:

- Reporting threshold
- Method of analysis
- POD, POI, Sizing accuracy.

The preliminary report shall be sent in electronic form to the Client within 4 weeks of the ILI run, unless agreed otherwise.

7.3 Final report

Standard criteria for the final report are given in this chapter, but can be changed if agreed between Client and Contractor.

The final inspection report (hard and electronic copy) of either a single or combined ILI tool run shall contain the information as described in this chapter and be submitted within 8 weeks of the ILI run, unless agreed otherwise.

The reporting thresholds shall (if not specified otherwise) be:

- For MFL tools: Metal loss with a depth ≥ 10% t for welded pipe and ≥15% for SMLS pipe
- For UT and other tools: Metal loss with a depth ≥ 1.0 mm
- Cracks with a length ≥ 25 mm
- Dents, ripples/wrinkles with a height/depth ≥ 1% ID
- Ovalities ≥ 5% ID.

7.3.1 Pipe tally

The pipe tally shall be a listing of all pipeline component features and anomaly features and should be reported in accordance with a typical report structure as given in Appendix 6 (including terminology, see Appendix 3 "Feature identification"). The Client can specify the pipe tally to specific requirements, e.g. add or delete specific columns.

The pipe tally shall be compatible with standard files such as CSV, ODS or another agreed format.

7.3.2 List of anomalies, clusters, data loss and other lists

Unless specified otherwise by the Client, the following lists shall be provided:

- List of anomalies:
  The list of anomalies shall contain the anomalies which are clustered if required by the interaction rules (according to chapter 2.6.1), with dimensions above the reporting threshold at POD=90% or above a reporting threshold as specified by the Client (including terminology, see Appendix 3). For a typical example see Appendix 7. *Note: if no defect interaction rule is applied, then this list can be waived in favour of the "List of individual anomalies", see below.*
- List of clusters:
  The list of clusters (according to chapter 2.6.1) shall contain the clusters and the individual anomalies that are part of the cluster. It shall be clearly indicated what anomalies form a certain cluster. For a typical example see Appendix 8.
- List of individual anomalies:

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The list of individual (all) anomalies shall be a listing of all anomalies without applying a defect interaction rule and with dimensions above the detection threshold at POD=90% or above a reporting threshold as specified by the Client.

- List of data loss:
  The list of data loss shall be a listing of all locations with data loss indicating the cause of data loss. *(Note: as data loss might be caused by e.g. a dent or debris whereby an anomaly can be missed such a location shall be carefully checked).*
- Other lists:
  If requested by the client a list with specific, to be indicated, items.

On the Client's request also the location of the deepest point in the metal loss area or clustered area shall be reported.

Unidentified/unknown features with strong signal shall be reported as "unknown" with, in commentary, an indication of the signal level.

The list of anomalies shall be compatible with standard files such as CSV, ODS or another agreed format.

7.3.3 List of components

The list of components shall be a listing of all feature types as listed in Appendix 3, except welds and anomalies. The list of components shall contain the same fields as the pipe tally.

The list of components shall be compatible with standard files such as CSV, ODS or another agreed format.

7.3.4 Summary and statistical data

The summary and statistical information as stated below should be agreed between Client and Contractor.

7.3.4.1 Metal loss

If a metal loss tool was run, the summary report for metal loss shall contain a listing of:

- Total number of anomalies
- Number of internal anomalies
- Number of external anomalies
- Number of anomalies for each metal loss anomaly class
- Number of anomalies per depth range of 10% (lower limit included)
- If applicable, number of anomalies per ERF range of 0.1, starting from 0.6 (lower limit included).

The following plots shall be provided:

- If applicable, sentenced plot including ERF=1 curve of anomaly length against metal-loss feature depth showing all anomalies for each representative wall thickness
- Orientation plot of all anomalies over the full pipeline length
- Orientation plot of all internal anomalies over the full pipeline length
- Orientation plot of all external anomalies over the full pipeline length
- Orientation plot of all anomalies as function of relative distance to the closest girth weld.

7.3.4.2 Cracks, crack-like and crack colonies

If a crack detection tool was run, the summary report for cracks, crack-like and crack colonies shall contain a listing of:

- Total number of anomalies per type and orientation to pipe axis
- Number of internal anomalies per type and orientation to pipe axis
- Number of external anomalies per type and orientation to pipe axis
- Number of anomalies per type per depth range of 2 mm and orientation to pipe axis (lower limit included).

The following plots shall be provided:

- Number of anomalies over the pipeline length
- Circumferentially orientated anomalies as function of relative distance to the closest girth weld
- Longitudinally orientated anomalies as a function of relative distance to the seam weld over the pipeline length.

7.3.4.3 Local and global geometry features

If a geometry tool was run, the summary report of geometry tool shall contain a listing of:

- Total number of dents, ripples/wrinkles, buckles
- Total number of ovalities
- Total number of joints with ovality
- Total number of other localized deformation/geometry anomalies
- Number of dents, ripples/wrinkles, buckles per depth range of 1%
- Number of ovalities per ratio range of 1%
- Number of joints with ovality per ratio range of 1%
- Orientation plot of all dents, ripples/wrinkles, buckles over the pipeline length
- Orientation plot of all ovalities over the pipeline length.

7.3.4.4 Other types of features (e.g. illegal taps)

If a tool capable of detecting other feature types was run, on request of the Client, the summary report for these features shall contain a listing of:

- Total number of features per type
- Number of internal features per type
- Number of external features per type
- Number of features per type per depth range of 10% (lower limit included).

The following plots shall be provided:

- Number of features over the pipeline length
- Orientation plot of all anomalies as function of relative distance to the closest girth weld
- Relative distance plot of all anomalies to the seam weld over the pipeline length.

The lists and plots as defined above can be completed at Client's request.

7.3.5 Performance

The final report shall contain:

- Completed tables A3-1 to A3-8 as per the Contract
- Completed tables A3-1 to A3-8 with actual run performance data depending on run conditions, tool functioning, pipeline cleanliness, etc.

Actual performance data must be given for each pipeline section where it is constant. These sections will be clearly identified.

7.3.6 Dig sheet

The purpose of the dig sheet is to provide the Client with all the information useful to carry out the field verification of a chosen feature.

Unless agreed otherwise, dig sheets shall be included in the final report.

Dig sheets shall contain the following information:

- Length of pipe joint and (when present) orientation of longitudinal or spiral seam at start and end of every joint
- Length and longitudinal or spiral seam orientation of the 3 upstream and 3 downstream neighbouring pipe joints
- Log distance of anomaly
- Wall thickness of the pipe joints (up to the 3 upstream and 3 downstream joints)
- Log distance of closest features like magnet markers, fixtures, steel casings, tees, valves, etc.
- Distance of upstream girth weld to nearest, second and third upstream marker
- Distance of upstream girth weld to nearest, second and third downstream marker
- Distance of anomaly to upstream girth weld
- Distance of anomaly to downstream girth weld
- Orientation of anomaly
- Geographical coordinates of an anomaly if a mapping unit was applied, including the Geodetic Datum Standard used. Unless specified otherwise, WGS84 shall be used
- Anomaly description and dimensions
- Internal/external/mid-wall indication.

7.3.7 Software and signal

In addition to the hard copy (if applicable), a user friendly software package shall be provided to enable review and assessment of the data collected by the inspection tool.

This software shall enable the Client to carry out the following tasks:

- Viewing of signal for each tool which was run, with possibility to modify gain, scale, etc.
- Preparing dig sheet for each anomaly (including dents, combined features, etc.)
- Plotting graphs and histograms
- Computing ERF (input data, models)
- Accessing detailed profile data for dents.

7.3.8 Anomaly ranking method for ERF

If requested by the Client, the Estimated Repair Factor for anomalies shall be reported on the basis of the assessment method indicated in Chapter 2.6.2 and input data shall be clearly stated in the final report.

ERF shall be reported for each individual feature. When clustering is applied, specific ERF for clusters shall be provided by the Contractor.

7.3.9 Detection of markers

AGMs or permanent markers that have been positively identified during the ILI run shall be indicated in the pipe tally. In addition, in the final inspection report the total number of installed AGMs and the number of identified AGMs shall be reported.

7.3.10 Personnel qualification

An overview of key personnel qualification level that has been deployed for the ILI tool run, data analysis, reporting and final report review shall be reported.

7.4 Raw data report

On request of the Client the raw data or processed raw data from an ILI run or a specific pipeline section shall be provided. The format of the data depends on the type of tool applied and is to be agreed between Client and Contractor and shall be defined in the inspection contract.

7.5 Multiple run comparisons report

If requested by the Client, anomaly data from two or more successive ILI runs carried out on the same pipeline, shall be compared individually and clustered. Aim is to detect discrepancies between reported anomalies of successive runs like new or missed features, corrosion growth, etc.

The run comparison report shall contain a table with matching and non-matching features per joint and include the results of these matching in terms of location, sizing and evolution. For a typical example see Appendix 9.

If the same Contractor is chosen for two successive inspection runs, the Client may request:

- A signal to signal comparison analysis between the two inspections
- A 2nd report based on the raw data of the previous inspection, but processed with the new algorithm.

The final run comparison report shall include the "Final report" (section 7.3) requirements and in addition:

- A comparison in terms of quality, velocity, performance and accuracy (tool rotation, velocity, acceleration, behaviour anomalies, magnetization level, ...)
- A comparison of used tools (performance, characteristics, number, type and distance between sensors, acquisition frequency, environment, magnetization, ...)
- A comparison of analysis and reporting parameters (e.g. but not limited to algorithms, thresholds, assessment code, interacting rules, ...)

7.6 Experience report

The experience report summarizes the operation. Good practices as well as possible improvements are reported. Special attention is paid to

- Project planning
- Interaction between interfaces
- Logistics on site
- Coordination with other operations
- Data quality
- Dig up results

The report will contribute to improved future operations.

7.7 Additional reporting

On request of the client an additional report might be requested including separate reports for each technology used in combination runs, Integrity assessment reports, etc.

8 References

1. Anon, "In-Line Inspection Systems Qualification", API 1163, American Petroleum Institute, 2nd Ed., April 2013.
2. Cosham, A. and Hopkin, P., "Pipeline Defect Assessment Manual (PDAM)", A Joint Industry Project, Penspen, 2013.
3. Anon, "Recommended Practices For Managing Near-Neutral Ph Stress Corrosion Cracking" 3rd Ed., Canadian Energy Pipeline Association (CEPA), May 2015.
4. Anon, "In-line Inspection Personnel Qualification and Certification" ANSI/ASNT-ILI-PQ-2005, American Society for Nondestructive Testing. 2010.
5. Anon, "Guidance on Achieving ILI First Run Success", Pipeline Operators Forum, December 2012.
6. Anon, "In-line Inspection Check Lists", Pipeline Operators Forum, December 2012.
7. Anon, "ILI Pipeline Questionnaire", Pipeline Operators Forum, December 2012.
8. Kastner, W., Rohrich, E., Schmitt, W. and Steinbuch, R., "Critical Crack Sizes in Ductile Piping", Int. J. Press. Ves. Piping 9 (3) 197–219, 1981.
9. Anon, "Fitness-For-Service", API 579-1/ASME FFS-1, American Petroleum Institute, 2016.
10. Anon, "Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures", BS 7910, British Standards Institution, 2013.
11. Anon, "Manual for Determining the Remaining Strength of Corroded Pipelines", ASME B31G, American Society for Mechanical Engineers, 2012.
12. Anon, "Corroded Pipelines", DNV-RP-F101, Det Norske Veritas, January 2015.

Appendix 1: ILI companies that provided comments to the draft version of these specifications

COMPANY	COUNTRY	WEBSITE
3P Services	Germany	www.3p-services.com
A. Hak Industrial Services	Netherlands	www.a-hak-is.com
Baker Hughes	USA	www.bakerhughes.com
General Electric (PII)	USA	www.geoilandgas.com/pii
NDT Global	Ireland	http://www.ndt-global.com
Pipe Survey International	Netherlands	www.pipesurveyinternational.com
PipeWay	Brazil	www.pipeway.com
Rosen	Switzerland	www.rosen-group.com
T.D. Williamson	USA	www.tdwilliamson.com
Quest Integrity	USA	www.questintegrity.com

Appendix 2: Guideline to clients for defining specific details of the POF specifications

Introduction

The POF document "Specifications and requirements for in-line inspection of pipelines" gives an outline of advised specifications for In-line-inspection (ILI) of pipelines. The Client should adapt certain specifications to reflect Client's specific requirements. For certain aspects of the inspection and/or reporting requirements, some options and default values are already considered, but the document gives the opportunity to define specific items. This guideline is intended to support the Client by listing the considered optional items in the specifications based on the expected integrity threats of the pipeline to be inspected. The items should be defined prior to sending the specifications to the ILI company and agreement of the contract.

In addition, in this guideline also some notes and advised specifications are given (*printed in Italic*), like the minimum requirements that are regarded essential for a successful ILI run.

Chapter 2.4.2 - Dent
The Client should agree with Contractor the methodology if strain based assessment is required and of minimum planar size accuracies of dents expected to be reported for technology selection.

Chapter 2.4.4 - Ovality
Default reporting is the maximum ovality measured. If another value shall be reported, this is to be indicated.

Chapter 2.4.6 - Ripple/Wrinkle
Maximum values shall be reported. If additionally also the maximum strain should be reported, the methodology shall be agreed between Client and Contractor.

Chapter 2.6.1- Interaction rules
ASME B31G methodology is specified as the default assessment method, but another methodology can be specified and agreed if required.

Chapter 2.6.2- Indication of anomaly severity (ERF)
The ASME B31G methodology is specified as the default assessment method for the ERF calculation, but another methodology can be specified if required.

Chapter 2.7 Resolution of measurement parameters
The Client shall specify if SI, metric or alternative units shall be used.

Chapter 2.7 – Coordinates for mapping work.
It is important for the client to specify the final coordinates required from the mapping data. Considerations will include using the latest geodetic system to ensure 'future proofing' of data, but also to ensure the data will match any existing mapping system used (which may in fact not be the latest system).

Chapter 0 - Health and Safety
Health and safety requirements to be agreed between Client and Contractor, including Client' policy on ATEX, IECEx or equivalent directive.

Chapter 3.1 – ATEX
Client shall specify if ATEX certification is required and if so, assess the zone classification.
Client shall specify, whether the Contractor shall ensure safe operation of ILI equipment under explosive conditions for pressures > .11 MPa during receiving and launching of tools.

Chapter 4.3
Client may request for information on tool readiness.

Chapter 4.4.1 - General
Client may request to complete the alternative table A5-3a in favour of tables A5-2 and A5-3.
If a higher level of performance is based on more detailed analysis, the additional performance level and commercial basis shall be agreed.

Chapter 4.4.4 Access to supporting performance information
If access on information in support of stated tool performance specification is requested, details on how and where shall to be agreed.

Chapter 4.6 - Changes to tool specification or performance specification sheets
Any requirement for reassessment of features as a result of tool specification changes shall be agreed (if required).

Chapter 0 - Personnel qualification
Default requirements for qualifications of key personnel are given but can be specified otherwise by the Client.

Chapter 6.2 - Contracting
Various contracting details should be specified.

Chapter 0 - Reporting
Two reports are indicated as standard (default). Additional reporting should be requested and agreed.

Chapter 7.1 - Operations report
Default time for reporting is within 2 days. Change of reporting time should be agreed.
Default content report is listed, modifications to be agreed.
Default values for acceptable data loss are given, modifications to be agreed.

Chapter 7.2 - Preliminary report
Default time for reporting is within 4 weeks. Change of reporting time should be agreed.
Default content report is listed, modifications to be agreed.
Typical reporting criteria are given, modifications to be agreed.

Chapter 7.3 - Final report
Default time for reporting is within 8 weeks. Change of reporting time should be agreed.
Default content report is listed, modifications to be agreed.
Default reporting thresholds are listed, modifications to be agreed.

In chapter 7.3.1 to 7.3.10 typical reporting options are listed and should be used as default. Modifications to be agreed.

Chapter 7.4 - RAW data report
If requested by Client, the raw data or processed raw data shall be provided by agreement.

Chapter 7.5- Multiple run comparisons report
If requested by Client, anomaly data from two or more runs shall be compared. A typical reporting structure is given, modifications to be agreed.

Chapter 7.6- Additional reporting
Any additional desired reporting should be requested and agreed upon by Client and Contractor.

Appendix 5 - Tool technology performance specifications
It is requested that the ILI company provides information on anomaly detection and sizing and other measurement capabilities of their tool. Below some typical values that can support the Client in his review of the proposed specifications.

POD of detected anomalies
The POD of a tool is normally taken at 90% and is based on anomalies with reference dimensions as given in the tables of appendix 5.

The typical minimal detectable depth of a high resolution MFL tool for general corrosion is 10% t and for pitting defects it is 15% t both with a POD of 90%. For seamless pipes and other category defects other values can apply.

The typical minimal detectable defect depth of a UT tool is 1 to 1.5 mm with a POD of 90%.

Depth, length and width sizing accuracies
The accuracy depends on the anomaly dimension class:
Typical for (high resolution) MFL tools: depth 10-15% t, length and width accuracy 10-20 mm
Typical for UT tools: depth 0.3 – 0.5 mm, length and width accuracy 10 mm
For anomaly depth, length and width sizing accuracy, the typical certainty level is 80%.

Accuracy of distance and orientation (clock position) of features:
Typical accuracy of distance to/from marker: 0.25% of distance
Typical accuracy of distance to closest weld: 0.15 m
Typical accuracy of circumferential position: 10°.

Certainty and accuracy of sizing deformations by geometry tool:
The certainties and accuracies of reported dents and ovalities shall be defined.
Typical certainties and accuracies are:

Ovalities:	*ID reduction, accuracy 1% of pipeline ID with certainty = 90%*
	Length, accuracy 10% of pipeline ID with certainty = 90%.
Dents:	*Depth, accuracy 1% of pipeline ID with certainty = 90%*
	Length, accuracy 10% pipeline ID with certainty = 90%
	Width, accuracy 10% pipeline ID with certainty = 90%.

Mapping: The accuracy of mapping is dependent on a variety of factors. Some of the main ones include the quality/technology of the IMU, the accelerometers, the odometer, the AGM's clock matching that of the inspection tool, the AGM's and also spacing of the accuracy with which the position of AGM is determined. Manufacturers and service providers will have varying technologies that provide varying accuracies.

It is generally thought that the accuracy of an IMU varies over distance travel, but the accuracy degrades over time, so it is important to consider the speed of the product in the pipe during the mapping inspection run. It is therefore important to specify maximum and minimum flow rates during mapping surveys.

AGM's are used to correct the IMU's 'drift' over time (and hence distance). The closer the AGM spacing, the more accurate the final coordinates will be. Many mapping runs use a 1 mile or 2 kilometre spacing, but for very or extremely high accuracy work 1 kilometre or even 500m spacing can be used.

AGM's should not be placed where the pipe is too deep for the inspection tool to be detected by the AGM.

Below are some reference documents that relate to magnetic properties for MFL inspection:

- *In "Magnetisation as a key parameter of magnetic flux leakage pigs for pipeline inspection" by H.J.M. Jansen, P.B.J. van de Camp and M. Geerdink (Insight Vol. 36, September 1994) it is concluded that MFL pigs are least sensitive to error sources (e.g. residual stresses, pressure, remnant magnetization) if the magnetic induction in the pipe wall > 1.8T. The magnetic field strength required to obtain such an induced magnetisation level depends on the type of material, wall thickness, pig speed etc.*
- *NACE International Publication 35100: "In-Line Non-destructive Inspection of Pipelines gives the following typical specifications for high-resolution MFL tools:*
  Minimum magnetic field strength: 10 to 12 kA/m (3 to 3.7 kA/ft)
  Minimum magnetic flux density: 1.7 T.

Mapping tool specifications

Geographical locations shall be reported in GPS coordinates by default, but another method can be specified if required.

Appendix 3: Report structure, terminology and acronyms

Column title	Unit	Prescribed terminology	Acronym	Explanatory note
Log distance	m	-		Starting point: trap valve
Abs up weld dist.	m	-		Absolute distance to upstream weld
L joint	m	-		Joint length to downstream weld
Feature type	-	- Above Ground Marker - Additional metal/material - Anode - Anomaly - Buckle arrestor begin/-end - Casing begin/-end - Change in wall thickness - CP connection - External support - Ground anchor - Off take - Other - Pipeline fixture - Reference magnet - Repair - Tee - Valve - Weld	AGM ADME ANOD ANOM BUAB/BUAE CASB/CASE CHWT CPCO ESUP ANCH OFFT OTHE PFIX MGNT REPA TEE VALV WELD	 Further identified below Further identified below Further identified below Further identified below
Feature identification	-	Additional metal/material: - Debris - Touching metal to metal - Other Anomaly: - Arc strike - Artificial defect - Blister - Buckle Global - Buckle Local - Buckle Propagation - Corrosion - Corrosion cluster - Corrosion related to CRA - Crack - Crack cluster - Dent complex - Dent kinked - Dent plain - Gouge - Gouge cluster - Grinding - Girth weld crack - Girth weld anomaly - Longitudinal weld crack - Longitudinal weld anomaly - Mill anomaly Grinding - Mill anomaly Lamination - Mill anomaly Lap - Mill anomaly Non-Metallic Inclusion	 DEBR TMTM OTHE ARCS ARTD BLIS BUCG BUCL BUCP CORR COCL COCR CRAC CRCL DENC DENK DENP GOUG GOCL GRIN GWCR GWAN LWCR LWAN MGRI MLAM MLAP MNOI	

		- Mill anomaly cluster - Ovality - Ripple/Wrinkle - Roof Topping - SCC - Spiral weld crack - Spiral weld anomaly Repair: - Welded sleeve begin/-end - Composite sleeve begin/-end - Weld deposit begin/-end - Coating begin/-end - Crack arrestor begin/end - Other begin/-end Weld: - - Bend begin/-end - Change in diameter - Change in wall thickness - Adjacent tapering - Longitudinal seam - Spiral seam - Not identifiable seam - Seamless	MACL OVAL RIWR ROTP SCC SWCR SWAN WSLB/WSLE CSLB/CSLE WDPB/WDPE COTB/COTE CRAB/CRAE OTHB/OTHE BENB/BENE CHDI CHWT ADTA LOSE SPSE NISE SMLS	No abbreviation for all welds different from welds below Applicable for: Pipe – pipe unequal WT
Feature class		- Axial Grooving - Axial Slotting - Circumferential Grooving - Circumferential Slotting - General - Pinhole - Pitting	AXGR AXSL CIGR CISL GENE PINH PITT	See Fig. 2.2 See Fig. 2.2 See Fig. 2.2 See Fig. 2.2 See Fig. 2.2 See Fig. 2.2 See Fig. 2.2
Clock position	h: min			See Fig. 2.1
Nominal t	mm			Nominal wall thickness of every joint
Reference t	mm			The actual not diminished wall thickness surrounding a feature
Length	mm			Anomaly length in axial direction
Width	mm			Anomaly width in circumferential direction
d (peak)	% or mm			If MFL: depth in % of ref t or nominal t*. If other technology in mm from ref t or nominal t*. *if ref. t is not available
d (mean)	% or mm			
Surface location		- Internal - External - Mid wall - Not applicable	INT EXT MID N/A	Location of anomaly on the pipeline: internal, external, mid wall or Not Applicable
ERF				
Comments	-	-		-

Appendix 4: Detailed tool data sheet requirements

Provide where appropriate following data.

Tool identification:

Tool type and model number
Unique reference number and date

Tool specifications:

Total Length:
Weight:
Number of Modules:
Maximum inspection range:
Maximum inspection time:
Inspection duration constraints: length of pipeline that can be inspected in one run due to e.g. wear of components, data storage limits or battery life:
Wall thickness range for full specification at minimum speed:
Wall thickness range for full specification at maximum speed:
Speed control range (if available):
Number and type of primary sensors:
Number and type of secondary (e.g. ID/OD) sensors:
Number of calliper/geometry sensors (if applicable):
Nominal circumferential centre to centre distance of primary sensors:
Longitudinal sampling distance: (specify values for either time or distance based):
Feature Location Accuracy - Axial
Feature Location Accuracy - Circumferential
Optimum tool speed Range:
One- or bi-directional design:

MFL specific:

- Direction of magnetization (axial/circumferential, helical) and polarity of magnetic field
- Required minimal magnetic field strength H in kA/m at the inner surface of the pipe to meet the given POD and sizing accuracy
- Type of magnet: (brushes, flaps, wear plates, wear knobs, wheels, ...).

Maximum circumferential secondary sensor spacing (i.e. circumferential centre to centre distance).

UT specific:

- Dimensions of UT transducers and diameter of crystal
- Frequency of UT signal
- Stand-off distance of UT transducers
- Diameter of UT beam at the inner pipe surface and outer pipe surface. The diameter of sound beam is defined by the diameter where the sound beam pressure is 6dB below the pressure at the centre of the beam
- Maximum tolerable attenuation in liquid and metal to receive sufficient response.

UT crack detection (in addition to UT specific)

- Angle of UT signal in steel
- Direction of angle of UT signal relative to pipe axis (longitudinal direction is 0°, circumferential is 90°).

Phased Array UT (in addition to UT crack detection)

- Number and dimensions of active elements within each transducer
- Range of angles of UT signal that can be generated in pipe wall.

EMAT UT:

- Type, mode and frequency of ultrasonic signal generated.

Safety:

ATEX and/or IECEx certification:
Type of batteries:
Magnetization hazard alert:
Pressurized containers alert:

Operating Parameters:

Maximum Operating Pressure:
Minimum Operating Pressure:
Temperature range:
Speed range for full performance specification:
Acceptable (proven) pipeline media (e.g. H2S, saline water, chemicals):
Excluded pipeline media:

Pipeline Parameters:

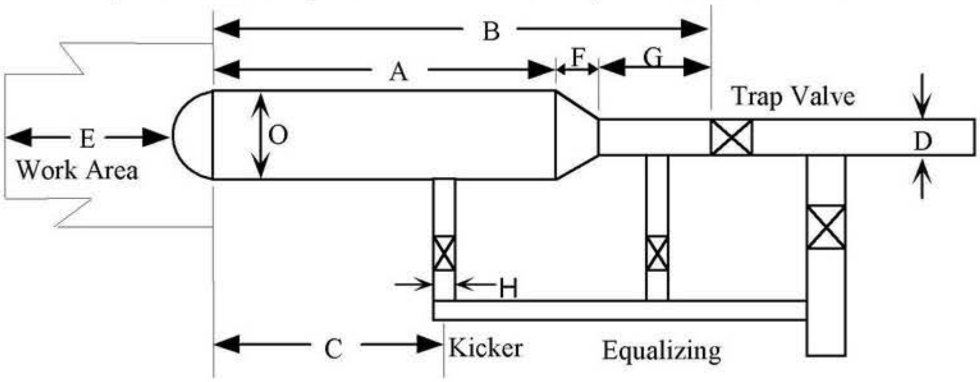
Maximum nominal bore:
Minimal nominal bore:
Minimum pipeline bend radius:
Minimal internal diameter in bend:
Maximum diameter barred:
Maximum diameter unbarred:
Minimum full bore adjacent tees:
Minimum full bore adjacent tees - Centreline separation:
Gauge plate diameter:
Back to Back bend capability:

Valves

Minimum ball valve bore:
Minimum gate valve bore:
Maximum void length:
Maximum Local Restriction:

Launcher and Receiver trap details

Launch and receive requirements including handling for vertical and horizontal traps:
Please provide a drawing with dimensions or complete the table below.



Trap Details		Launcher Dimensions (mm)	Receiver Dimensions (mm)
8.1.1 A	Closure to reducer		
B	Closure to trap valve		
C	Closure to bridle CL		
D	Pipeline internal diameter		
O	Overbore internal diameter		
E	Axial clearance		
F	Reducer length		
G	Reducer to valve		
H	Bridle		

SoCalGas-7.0127

Appendix 5: Tool technology performance specifications

Tool technology performance specifications shall define the ability of the ILI system to detect, locate, identify, and size pipeline features, components and anomalies. It is typically linked to the inspection technology applied in the tool e.g. High resolution MFL, standard MFL, Ultrasonic pitting detection tool, Ultrasonic wall thickness measuring tool etc.

The tool performance specifications as listed in this appendix shall be given. The influence of the operating or pipeline variables on the performance specifications shall be clearly indicated via e.g. correction factors or additional tables.

Essential variables that might influence the specifications and possibly require additional specifications are e.g. (but not limited to) listed below:

General specifications:

- Tool inspection technology
- Tool speed range
- Maximum axial sampling interval
- Maximum circumferential primary sensor spacing (i.e. circumferential centre to centre distance)
- Influence of line pipe manufacturing process (e.g. SAW, HFW, Seamless, etc)
- Influence of the location of the anomaly with respect to girth weld and/or seam weld; i.e. the ability to detect and size anomalies in and near weld and HAZ
- Influence of curvature of the pipeline, i.e. minimal bend radius.

MFL specific:

- Direction of magnetisation (axial/circumferential/ spiral) and polarity of magnetic field
- Required minimal magnetic field strength H in kA/m at the inner surface of the pipe to meet the given POD and sizing accuracy
- Maximum circumferential secondary sensor spacing (i.e. circumferential centre to centre distance).

UT specific:

- Dimensions of UT transducers and diameter of crystal
- Frequency of UT signal
- Stand-off distance of UT transducers
- Diameter of UT beam at the inner pipe surface and outer pipe surface. The diameter of sound beam to be defined by the dimension where the sound beam pressure is 6dB below the pressure in the centre of the beam.
- Maximum tolerable attenuation in liquid and metal to receive sufficient response.

UT crack detection (in addition to UT specific)

- Angle of UT signal in steel
- Direction of angle of UT signal relative to pipe axis (longitudinal direction is 0°, circumferential is 90°).

Phased Array UT (in addition to UT crack detection)

- Number and dimensions of active elements within each transducer
- Range of angles of UT signal that is generated in pipe wall.

EMAT UT:

- Type, mode and frequency of ultrasonic signal generated.

Table A5-1: Identification of features

Feature	Yes POI>90%	No POI<50%	May be 50%<=POI<=90%
Int./ext./mid wall discrimination			
Additional metal/material:			
- debris, magnetic			
- debris, non-magnetic			
- touching metal to metal			
- Other			
Anode			
Anomaly:			
- arc strike			
- artificial defect			
- blister			
- buckle global			
- buckle local			
- buckle propagation			
- corrosion			
- corrosion cluster			
- corrosion related to CRA			
- crack			
- crack cluster			
- dent kinked			
- dent plain			
- dent smooth			
- gouge			
- gouge cluster			
- grinding			
- girth weld crack			
- girth weld anomaly			
- longitudinal weld crack			
- longitudinal weld anomaly			
- mill anomaly - grinding			
- mill anomaly lamination			
- mill anomaly lap			

- mill anomaly non-metallic inclusion			
- mill anomaly cluster			
- ovality			
- ripple/wrinkle			
- SCC			
- spalling			
- spiral weld crack			
- spiral weld anomaly			
Eccentric pipeline casing			
Change in wall thickness			
CP connection/anode			
External support			
Ground anchor			
Off take			
Pipeline fixture			
Reference magnet			
Repair:			
- welded sleeve begin/end			
- composite sleeve begin/end			
- weld deposit begin/end			
- coating begin/end			
- crack arrestor begin/end			
Tee			
Valve			
Weld:			
- bend			
- diameter change			
- wall thickness change (pipe/pipe connection)			
- adjacent tapering			
- longitudinal weld			
- spiral weld			
- not identifiable seam			
- seamless			

Table A5-2: MFL detection and sizing accuracy for metal loss anomalies

	General metal-loss	Pitting	Axial grooving	Circumf. grooving	Pinhole	Axial slotting	Circumf. Slotting
Depth at POD=90%					N/A see below		
Depth sizing accuracy at 90% certainty							
Width sizing accuracy at 90% certainty							
Length sizing accuracy at 90% certainty							
Minimum pinhole diameter at POD=90% if depth=50%t						n.a.	
Minimum pinhole diameter at POD=90% if depth=20%t						n.a.	

Table A5-3: Metal loss detection and sizing accuracy for technologies other than MFL.

Detection but no sizing at POD=90%	Minimum diameter	
	Minimum depth	
Detection and sizing at POD=90%	Minimum diameter	
	Minimum depth	
Depth sizing accuracy at 90% certainty		
Length sizing accuracy at 90% certainty		
Width accuracy at 90% certainty		
Accuracy of wall thickness measurement at 90% certainty		

Table A5-3a: Detection and sizing of internal and external metal loss, regardless of technology. One table for each wall thickness must be filled out. Note: this table might be requested by the Client as an alternative for tables A5-2 and A5-3.

Wall Thickness xx-xx mm, POD/POI =90%							
Technique	Speed interval for stated detection limit and accuracy, m/s	Minimum defect size, Internal			Minimum defect size, External		
		Depth, mm	Length, mm	Width, mm	Depth, mm	Length, mm	Width, mm
Technique 1							
Technique 2							
Resulting tool performance							

Table A5-4: Detection and sizing accuracy for cracks or crack-like anomalies.

	Axial crack Pipe body/weld	Axial crack colony Pipe body	Circumferential crack Pipe body/weld	Spiral crack Pipe body/weld
Depth at POD=90% of crack with L=25 mm				
Minimum crack opening (mm)				
Depth sizing accuracy at 90% certainty				
Length sizing accuracy at 90% certainty				
Orientation limits (in degrees) for detectability				

Table A5-5: Detection and sizing accuracy for dents, ovalities, ripples/wrinkles, buckles

	Dent	Ovality
Height/Depth POD=90%		n.a.
Height/Depth sizing accuracy at 90% certainty		n.a.
Width sizing accuracy at 90% certainty		n.a.
Length sizing accuracy at 90% certainty		
Ovality at POD=90%	n.a.	

Table A5-6: Detection and sizing accuracy in 90° bends.

Minimal bend radius for detection of metal loss anomalies as given in Table A5-2, A5-3, A5-3a	OD*
Minimal bend radius for sizing accuracy for metal loss anomalies as given in Table A5-2, A5-3, A5-3a	OD*
Minimal bend radius for detection of crack or crack-like anomalies as given in Table A5-4	OD*
Minimal bend radius for sizing accuracy of crack or crack-like anomalies as given in Table A5-4	OD*

* If the bend radius in the pipeline is smaller than given in the table, then applicable specifications for that bend radius shall additionally be provided in the form of Tables A5-2, A5-3, A5-3a or A5-4.

Table A5-7: Location accuracy of features.

Accuracy of distance to upstream girth weld at 90% certainty	
Accuracy of distance from trap valve at 90% certainty	
Accuracy of circumferential position at 90% certainty	

Table A5-8: Mapping tool accuracy and horizontal and vertical accuracy of pipeline location as function of marker distance and certainty.

Accelerometer accuracy (micro g)		
Gyroscope accuracy (°/h)		
Horizontal accuracy (m) at 90% certainty	Vertical accuracy (m) at 90% certainty	Marker distance (m) (add rows to table if required)
0.5	0.5	
1.0	1.0	
2.0	2.0	

The values to be entered in this table depend on the accuracy of the individual company's technology and their way of operating their system as a whole. It is generally thought that the accuracy of an IMU varies over distance travelled, but the accuracy degrades over time, so it is important to consider the speed of the product in the pipe during the mapping inspection run. It is therefore important to specify, in consultation with the Contractor, the maximum and minimum flow rates during mapping surveys as well as spacing of AGMs. Very slow rates will reduce accuracy.

AGM's are used to correct the IMU's 'drift' over time (and hence distance). The closer the AGM spacing, the more accurate the final coordinates will be. Many 'standard' mapping runs use a 1 mile or 2 kilometre spacing, but for very or extremely high accuracy work 1 kilometre or even 500m spacing can be used.

Appendix 6: Typical example of Pipe tally*

	GPS coordinates			Feature type and ID			Reference joint						Joint global geometry		Feature location on joint			Anomly sizing and further information: Deformations			Anomly sizing and further information: Cracks and metal losses							
Log distance [m]	latitude	longitude	altitude [m]	Feature type	Feature identification	Comment / Cluster ID	Girth weld Nr	Joint manufacturing type	Joint / component length [m]	Internal diameter [mm]	Nominal thickness [mm]	Measured/reference thickness [mm]	Ovality [%]	Bend Y/N	Abs. Dist. to upstream weld [m]	Clock position seam weld / anomaly	Surface location	Inward/outward	Depth / height [%.D or mm]	Size (length x width) [mm]	Mean depth [%.t or mm]	Max. depth [%.t or mm]	Length [mm]	Width [mm]	Anomaly dimension classification	ERF (metal losses)	Reference table for performance	Comments
-1.136				Weld			10	Seamless	2.272	508	14	14.2																
0				Valve		Starting point: City									1.136													
1.136				Weld	Change wall thickness		20	Seamless	8.001	508	12	12.3	0.8														A3-5	
9.137				Weld			30	Long seam	12.001	508	12	12.1	0.4			8:04											A3-5	
21.138				Weld	Change wall thickness	Adjacent tapering	40	Spiral seam	12.001	508	8	8.4	0.2			4:42											A3-5	
23.139				Anomaly	Corrosion	Abnormal signal						8.4			2.001	10:32	Ext				18%	25%	126	42	GENE	Not calculated	A3-2	
30.143				Above ground marker	Marker	AGM 1									9.005													
33.141				Weld			50	Long seam	11.003	508	8	8.3	1.2			7:26											A3-5	
35.001				Anomaly	Dent, Kinked	Mechanical damage						8.3			12.860	0:22	Ext	Inw	2.7%	45x78	12%	21%	31	67	GENE	Not calculated	A3-2	
35.801				Anomaly	Gouge Cluster	GOCL-01						8.3			2.800	0:10	Ext				8%	15%	38	20	AXGR	Not calculated	A3-2	
44.144				Weld	Bend begin	Adjacent tapering	60	Long seam	2.004	508	12	12.2	0.9	Y		1:38												Installation S-449
44.999				Anomly	Corrosion Cluster	COCL-01						12.1		Y	0.855	8:36	Ext				32%	32%	42	25	PITT	Not calculated	A3-2	
46.148				Weld	Bend end	Adjacent tapering	70	Long seam	11.145	508	8	8.4	0.8			11:10												Installation S-449
47.151				Anomaly	Mill anomaly Cluster	MACL-01						8.4			1.003	8:53	Int				17%	36%	159	120	GENE	Not calculated	A3-2	
57.293				Weld			80	Long seam	10.999	508	8	8.5	0.9			7:12											A3-5	

* Columns can be added or deleted, e.g. depending on the ILI tool technology/technologies applied and/or on request of the Client.

Appendix 7: Typical example List of anomalies*

	GPS coordinates			Feature type and ID			Reference joint						Joint global geometry		Feature location on joint			Anomaly sizing and further information										
																		Deformations			Cracks and metal losses							
Log distance [m]	latitude	longitude	altitude [m]	Feature type	Feature identification	Comment / Cluster ID	Girth weld Nr	Joint manufacturing type	Joint / component length [m]	Internal diameter [mm]	Nominal thickness [mm]	Measured/reference thickness [mm]	Ovality [%]	Bend Y/N	Abs. Dist. to upstream weld [m]	Clock position seam / anomaly	Surface location	Inward/outward	Depth / height [%.D or mm]	Size (length x width) [mm]	Mean depth [%.t or mm]	Max. depth [%.t or mm]	Length [mm]	Width [mm]	Anomaly dimension classification	ERF (metal losses)	Reference table for performance	Comments
23.139				Anomaly	Corrosion	Abnormal signal						8.4			2.001	10:32	Ext				18%	25%	126	42	GENE	Not calculated	A3-2	
35.001				Anomaly	Dent, Kinked	Mechanical damage						8.3			12.860	0:22	Ext	Inw	2.7%	45x78	12%	21%	31	67	GENE	Not calculated	A3-2	
35.801				Anomaly	Gouge Cluster	GOCL-01						8.3			2.800	0:10	Ext				8%	15%	38	20	AXGR	Not calculated	A3-2	
44.999				Anomaly	Corrosion Cluster	COCL-01						12.1		Y	0.855	8:36	Ext				32%	32%	42	25	PITT	Not calculated	A3-2	
47.151				Anomaly	Mill anomaly Cluster	MACL-01						8.4			1.003	8:53	Int				17%	36%	159	120	GENE	Not calculated	A3-2	

* Columns can be added or deleted, e.g. depending on the ILI tool technology/technologies applied and/or on request of the Client.

Appendix 8: Typical example List of clusters*

	GPS coordinates			Feature type and ID			Reference joint						Joint gobal geometry		Feature location on joint			Anomly sizing and further information											
																		Deformations			Cracks and metal losses							
Log distance [m]	latitude	longitude	altitude [m]	Feature type	Feature identification	Comment / Cluster ID	Girth weld Nr	Joint manufacturing type	Joint / component length [m]	Diameter [mm]	Nominal thickness [mm]	Measured/reference thickness [mm]	Ovality [%]	Bend Y/N	Abs. Dist. to upstream weld [m]	Clock position seam / anomaly	Surface location	Inward/Outward	Depth / height [%.D or mm]	Size (lenght x width) [mm]	Mean depth [%.t or mm]	Max. depth [%.t or mm]	Length [mm]	Width [mm]	Anomaly dimension classification	ERF (metal losses)	Reference table for performance	Comments
35.801				Anomaly	Gouge Cluster	GOCL-01						8,3			2.8	0:10	Ext				8%	15%	38	20	AXGR	Not calculated	A3-2	
35.801					Gouge	GOCL-01.01						8.3			2.8	0:10	Ext				7%	12%	30	11	AXGR	Not calculated	A3-2	24° angle
35.811					Gouge	GOCL_01.02						8.3			2.8	0:14	Ext				5%	15%	28	12	AXGR	Not calculated	A3-2	35° angle
44.999				Anomly	Corrosion Cluster	COCL-01						12.1			0.855	8:36	Ext				32%	32%	42	25	PITT	Not calculated	A3-2	
44.999					Corrosion	COCL-01-01						12.1			0.855	8:36	Ext				24%	24%	12	12	PITT	Not calculated	A3-2	
45.015					Coprrosion	COCL-01-02						12.1			0.871	8:43	Ext				36%	36%	26	20	PITT	Not calculated	A3-2	
47.151				Anomaly	Mill anomaly Cluster	MACL-01						8.4			1.003	8:53	Int				17%	36%	159	120	GENE	Not calculated	A3-2	
47.151					Grinding	MACL-01-01						8.4			1.003	9:16	Int				14%	36%	64	70	GENE	Not calculated	A3-2	
47.221					Non-metallic inclusion	MACL-01-02						8.4			1.073	9:42	Int				12%	12%	10	12	PITT	Not calculated	A3-2	
47.232					Lamination	MACL-01-03						8.4			1.084	8:53	Mid				11%	24%	78	55	GENE	Not calculated	A3-2	

* Columns can be added or deleted, e.g. depending on the ILI tool technology/technologies applied and/or on request of the Client.

Appendix 9: Typical example Run comparison overview*

DATA RUN 1 (yyyy-mm-dd)															DATA RUN 2 (yyyy-mm-dd)															Difference				
Log distance [m]	Latitude	Longitude	Altitude	Girth weld number	Joint / component length [m]	Wall thickness [mm]	Abs. dist. feature to upstream weld [m]	Feature	Clock position	Length [mm]	Width [mm]	Depth %	Int / Ext	...	Log distance [m]	Latitude	Longitude	Altitude	Girth weld number	Joint / component length [m]	Wall thickness [mm]	Abs. dist. feature to upstream weld [m]	Feature	Clock position	Length [mm]	Width [mm]	Depth %	Int / Ext	...	Δ Length [mm]	Δ Width [mm]	Δ Depth %	...	Comment
10,250.250				7500	14.651	10.0		weld							10,250.000				7500	14.811	10.5		weld											Weld matched
10,256.630						10.0		corrosion	6:00	35	40	12	Int		10,257.000								corrosion	5:42	120	80	18	Int		85	40	6		Corrosion matched
															10,262.650								corrosion	4:12	15	10	5	Int						New corrosion
10,263.305						10.0		grinding	11:04	120	80	8	Ext		10,263.500								corrosion	11:00	140	90	12	Ext		20	10	4		Identification correction: grinding to corrosion
10,264.910				7510	15.100	10.0		weld							10,264.818				7510	15.080	10.5		weld											Weld matched
10,280.008				7520	15.000	10.0		weld							10,279.898				7520	3.110	10.5		weld											Weld matched
															10,283.000				7522	7.000	12.5		weld											New weld
															10,290.064				7524	4.905	10.5		weld											New weld
10,294.800				7530	14.805	10.0		weld							10,294.900				7530	14.805	10.5		weld											Weld matched

* Columns can be added or deleted, e.g. depending on the ILI tool technology/technologies applied and/or on request of the Client.

Ex. II - 11

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Casing Mechanical Integrity Tests Utilizing Wireline Ultrasonic Imaging Logs

Jerry Rushing

Schlumberger Well Services
Signal Hill, CA 90806

Keywords
Ultrasonic, logs, logging, mechanical integrity, corrosion

ABSTRACT

The UltraSonic Imager Tool (USIT) is a wireline conveyed logging tool used for cement and casing evaluation. The tool and acquisition system utilize color imaging to present the measurements obtained from a rotating ultrasonic transducer, which gives 360° coverage at high resolution. For mechanical integrity tests, the most important measurements are casing internal radius and casing thickness. A presentation of the cement bonding to the casing is also derived from its measurement. Based on these measurements and the radial color maps generated from them, interpretations are made as to the metal loss and general condition of the casing.

Since the Bureau of Land Management started requesting that mechanical integrity tests be performed, geothermal operators have utilized the USI tool to help them evaluate and optimize their operations. Currently, one operator is using titanium casing in hopes of extending the well life. Also, types of latex based foam cements are being used to cement the newer casing strings. A study is currently ongoing through a consultant and Sandia Laboratories to examine the USI measurement and parameters in these new environments. Various examples illustrate typical log results of heavy internal scaling, corrosion, mechanical wear, and cement bonding. Examples will also show the changes in the wellbore environment over time and the effect of "clean out" jobs on internal scale. Recovered casing is shown to validate the log results.

Introduction

Geothermal operators are using the USI tool for various purposes in evaluation of their casing. The bulk of the evaluation is performed in geothermal injection wells. The Bureau of Land Management started in 1994 requesting that injection wells older than 3 years old have a mechanical integrity test of their casing performed every other year. Acceptable techniques were conventional packer pressure tests and/or wireline logging. The most common failure in the Holtville area is from shallow external corrosion. Because of this fact and the fact that the BLM criteria was based on remediating casing with 25% or greater metal loss, the conventional packer pressure tests did not make sense as they did not provide the information and accuracy needed to make these decisions.

The technique of utilizing the USI wireline technology has allowed for evaluations and interpretations to be made conveniently and cost effectively for a monitoring program of the casing condition. The accuracy and repeatability of the device gives confidence in the interpreted results. Approximately 30 geothermal wells are logged each year in the geothermal areas of Southern California. A discussion of the tool measurement and following field examples show how the tool is utilized in the ongoing monitoring of casing mechanical integrity.

Principle of Measurement

The ultrasonic transducer of the USI serves as both the transmitter and receiver of acoustic energy. A short pulse of acoustic energy is emitted and received as multiple echoes from the casing and cement. These multiple echoes create a resonance in the casing relative to its thickness. The presence of cement bonded to the casing is detected as dampening of the resonance.

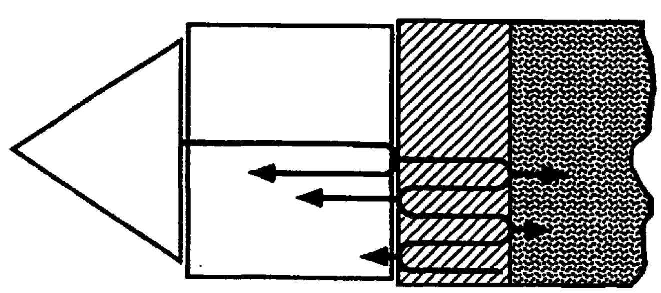

Figure 1. USI principle of measurement.

Table 1: Acoustic properties of materials.

Material	Density (kg.m-3)	Acoustic Velocity (m.s.-1)	Acoustic Impedance (MRayl)
Air (1-100 bar)	1.3 - 130	330	0.0004 - 0.04
Water	1000	1500	1.5
Drilling fluids	1000 - 2000	1300 - 1800	1.5 – 3.0
Cement slurries	1000 - 2000	1500 – 1800	1.8 – 3.0
Cement (Litefil)	1400	2200 - 2600	3.1 – 3.6
Cement (class G)	1900	2700 - 3700	5.0 – 7.0
Limestone	2700	5500	17
Steel	7800	5900	46

The transducer subs are appropriately sized to position the transducer one to two inches from the casing wall. The largest reflection of the acoustic energy pulse is from the internal casing interface, with a small fraction of the signal entering the casing. This smaller fraction resonates with energy lost back to the wellbore fluid at each reflection. (See Figure 1, previous page).

An analysis of the echoes yields four measurements:

1. Echo amplitude – an indicator of casing condition
2. Internal radius – calculated from the travel time of the echo.
3. Casing thickness – calculated from the resonance frequency.
4. Acoustic impedance – calculated from the dampening of the resonance.

The acoustic impedance is the basis for cement evaluation. In a homogeneous medium, the acoustic impedance Z is equal to the product of the density ρ and acoustic velocity v:$Z = \rho v$. Acoustic impedance is expressed in units of Mrayl. Table 1 lists acoustic properties of some materials encountered.

In order to accurately measure internal diameter and thickness of the casing, and to determine the cement bonding from impedance, the USI needs to measure the velocity and acoustic impedance of the wellbore fluid. Fluid density changes and temperature affects the fluid velocity and impedance measurements.

The tool has a separate operating mode to only measure the wellbore fluid properties (see Figure 2).

- In the fluid properties mode, the transducer faces inward towards a target plate. The plate properties are known and therefore the properties of the fluid between the transducer and the plate can be measured.
- In the logging position, the transducer faces outward towards the casing wall.

The fluid properties mode is used when logging while running into the well. These values obtained are then input at the appropriate depth as the tool is logged up in the logging mode.

Because this is a geothermal environment, the temperature limitations of 350° F have to be considered prior to logging. Simply injecting water can usually cool the injection wells. However, the scaling problem that exists is some areas are not that easily overcome. Internal scaling will create an environment in which accurate data cannot be obtained. Acid cleanouts and scale blasting techniques are employed to sufficiently clean these problem wells.

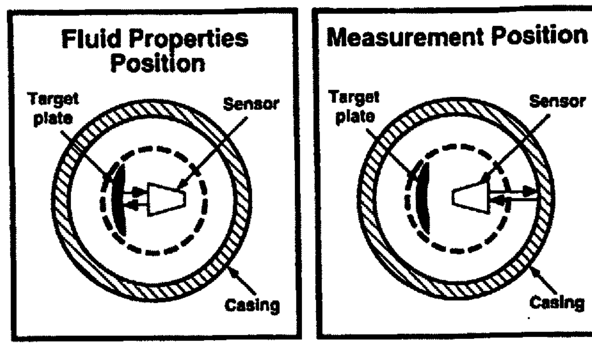

Figure 2. Rotating sub operating positions

Field Examples

Each of the following log examples emphasizes the point that color images and logs are critical to the interpretations as they are difficult to view and understand in black and white.

Field Example #1 Corrosion

This example clearly shows the value and effectiveness of the corrosion monitoring program utilizing the Ultrasonic Imager. Shown in Figures 3 and 4 are two of the three USIT logs, which were run on the same well. This well has been logged three times at two-year intervals as required by the BLM for the monitoring of casing integrity. The area of focus is the upper section of the 13 3/8" just below where the tool enters the well head master valve. The first log (not

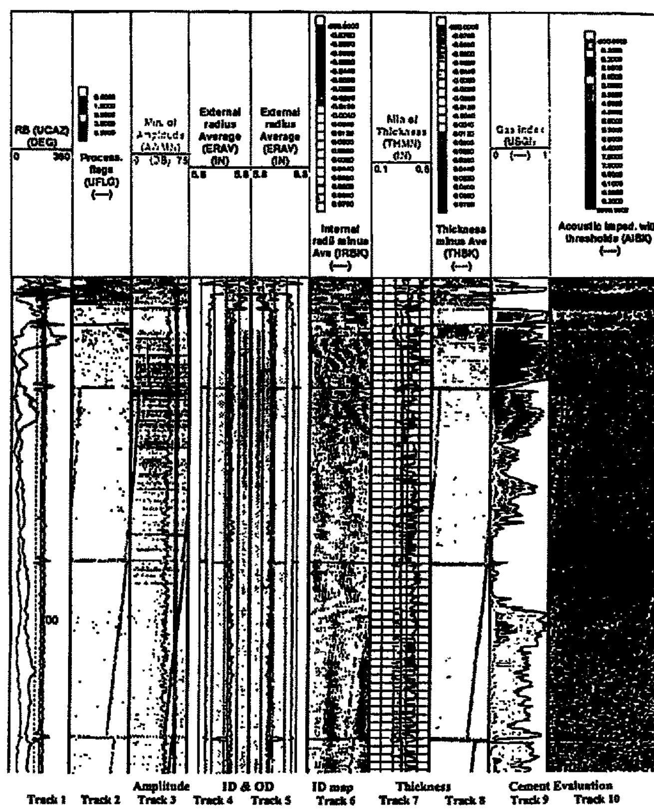

Figure 3. Log 1 with minor corrosion.

shown here) showed no evidence of corrosion. The second log, Figure 3, recorded two years later shows a small patch of external corrosion at a log-measured depth of 24'-29' with approximately 20% metal loss. The third log, Figure 4, recorded two years later shows the external corrosion is now extending downfrom 24' -55' with approximately 30% metal loss. The corrosion is most easily recognized in the thickness map display, which is Track 6 of the log display. It shows up as the darker areas in the black and white copy. The corrosion appears to be predominately on one side of the pipe. Figures 5 and 6 are photos of the casing that was excavated which confirms the log response and the severity of external corrosion.

Example #2 Cement Analysis

In the last few years, there has been the introduction of running titanium casing and latex based foam cements in a few wells. Although the USIT was not initially characterized for these materials, new parameters and processing have been developed to accurately analyze both the cement bond and the casing thickness. Figures 7 and 8 (overleaf) are two logs created from the same acquired raw data. Figure 7 is the original log using parameters for titanium casing and the micro-debonding processing to identify the foam and latex cement. The micro-debonding processing uses logic that says if it doesn't see "normal" cement or water filled space, it then compares each measurement with the one above, below, left and right of it. If the fluid type is water or drilling fluid, these measurements are consistent with each other. When the software

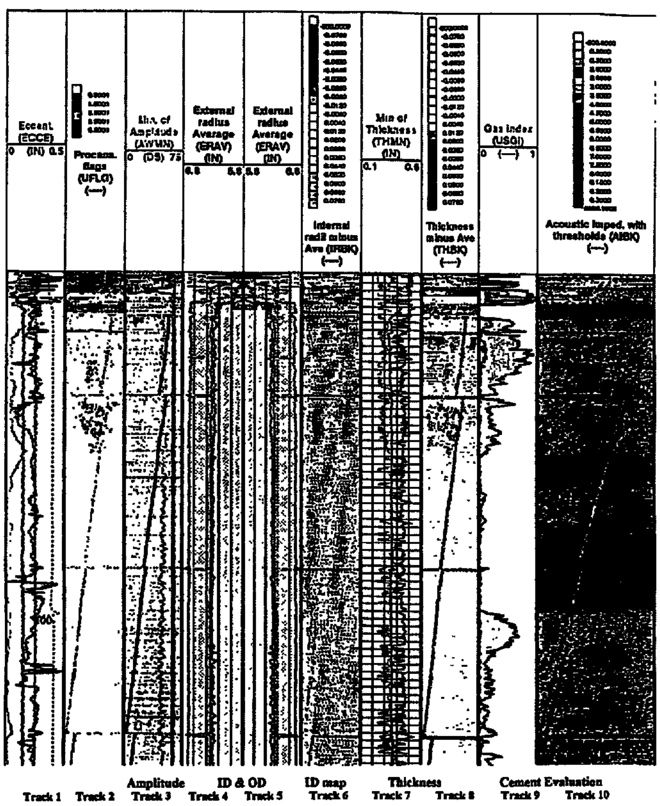

Figure 4. Log 2 with increased corrosion.

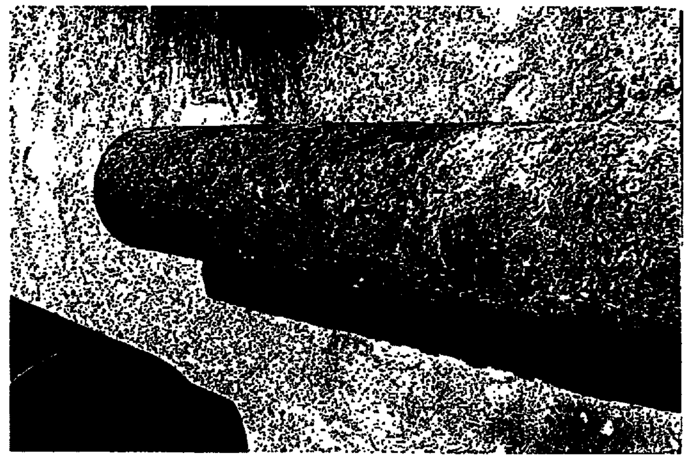

Figure 5. Excavated casing confirming external corrosion.

Figure 6. Close up of external corosion.

recognizes differences in the surrounding measurements it codes it as such. This should incorporate gas or mud contaminated cements, and the foam and latex cements. In Figure 7, the thickness measurement is accurate and the cement is recognized and interpreted with the new processing. Figure 8 is the same log data played with parameters for steel casing and standard USIT processing for the cement evaluation. The output for thickness is now too high and the area where we were seeing cement is now being classified as gas and many processing error flags are present in Track 2. A current review and study is underway with a consultant and Sandia Laboratories to analyze the parameters used by the USIT for various cement types in both steel and titanium.

Example #3 Drill Wear

Figures 9, 10 and 11 are part of an example which shows a case of drill wear. Figure 9 is of the USIT log taken from the well. The wear extends for almost 50'. The fact that the defect shows up as an increase in the ID in Track 6 and a loss of metal thickness in Track 8 indicates that it is internal wear of the pipe. The amplitude map is Track 3 also clearly shows the wear groove. Figure 10 is photo of the recovered casing. Figure 11 is a cross sectional plot taken from the depth of the wear with

Titanium Casing & Latex-Foam Cement

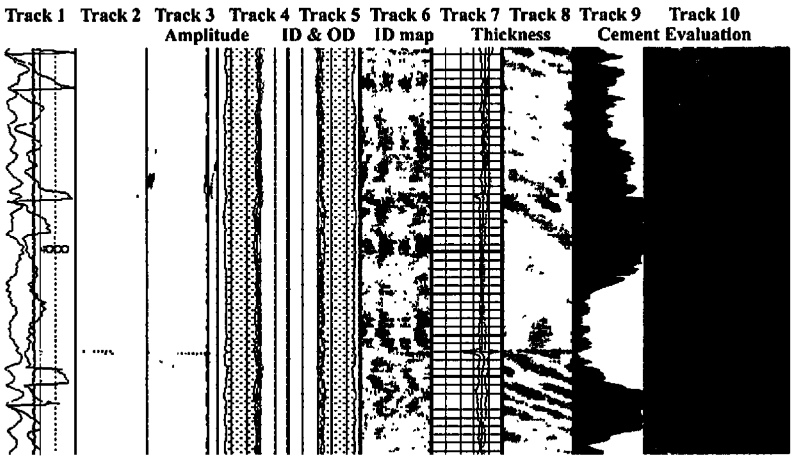

Figure 7. Correct settings for titanium and latex-foam cement.

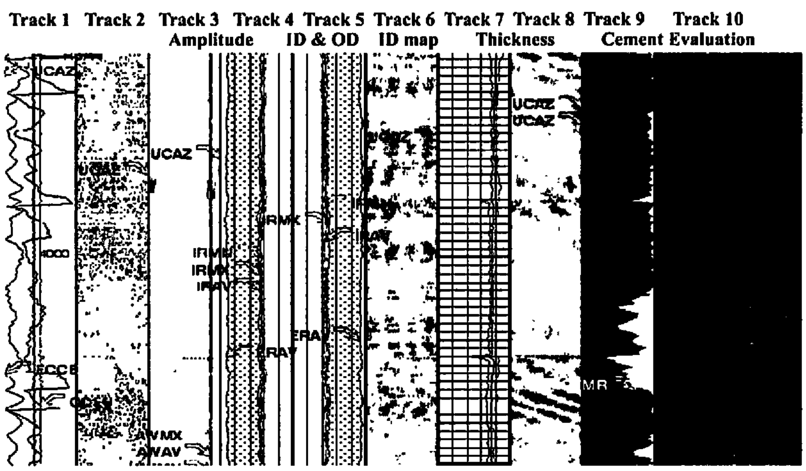

Figure 8. Log replayed with standard settings for steel & neat cement.

Mechanical Wear

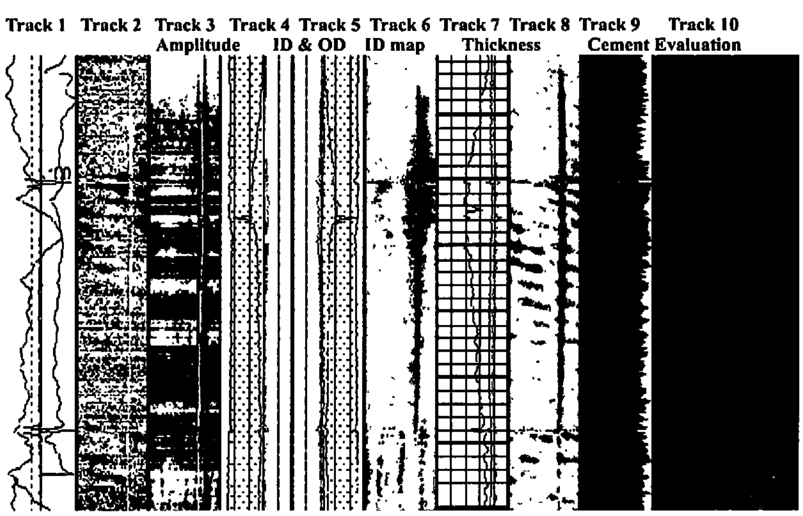

Figure 9. Mechanical wear evident.

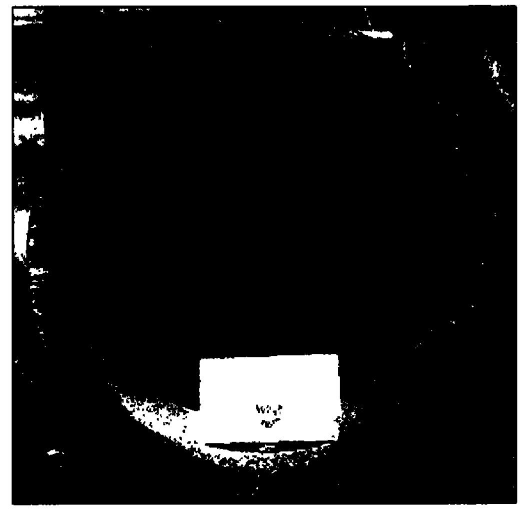

Figure 10. Excavated casing.

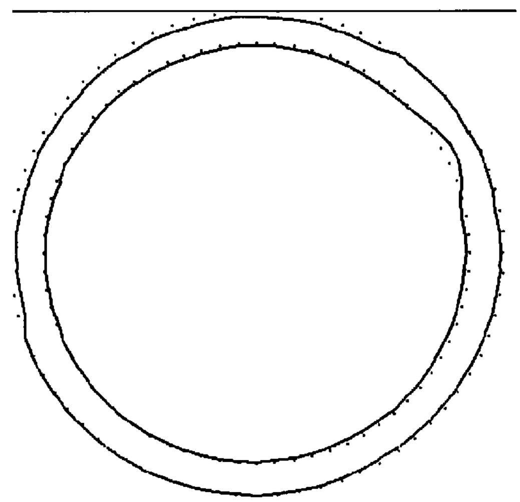

Figure 11. Plot from USIT log.

the USIT. Notice the casing OD is still round but the ID and thus the thickness change on the worn side. The thickness measurement of the USIT is accurate from 0.27" to 0.59". In this case, the excavated casing was actually thinner than the 0.27" USIT measurement that is represented on the log and the cross section plot.

Example #4 Internal Scaling

This is a log example of internal scaling and subsequent cleaning. Some areas in the geothermal areas in Southern California have a problem with a soft internal scale. This soft scale is identifiable by the dark impedance and by "grooves" in Track 3. These "grooves" are impressions made in the internal scale by the centralizing arms on the USI tool. Figures 12 and 13 are two logs recorded from the same well at different times. Figure 12 shows the presence of a heavy build-up of soft internal scale. The grooves left by our centralizing arms are slightly visible in Track 3 of the log by the lighter vertical stripes against the darker scale. Figure 13 shows the casing condition after an acid clean-out was performed. For some reason, the clean-out was very effective down to 622'. This log comparison is an outstanding example of how the scale affects the log response. Prior to the clean-out, the minimum and maximum internal diameter measurements and the minimum and maximum thickness measurements are very erratic. This makes the data unreliable for a detailed and accurate interpretation. The average thickness measurement is still accurate. After the clean-out, the measurements above the depth of 622' are of very good quality. The interpretation of the data can be made accurately and confidently.

Conclusion

The USI tool is being used by the geothermal operators to monitor casing conditions as required by the Bureau of Land Management.

1. The USI has been proven to be effective in identifying external corrosion and been verified by excavations done by geothermal operators. External corrosion near the surface is the most prevalent in the Holtville area.
2. Current software processes are being qualified to provide accurate measurements in newer environments of titanium casing and latex based foam cements.
3. The accuracy of the internal radius and thickness measurement from the USI tool makes it a very effective tool for evaluating mechanical wear and to base wellbore decision on.
4. The USI has been useful in long term monitoring of corrosion, scale increase, and the effectiveness of clean out jobs. Heavy buildup of soft internal scale is problematic is certain areas and makes it very difficult to get a reliable interpretation of the casing and cement condition.
5. Color imaging and 360° coverage of the USI presentation are critical to the interpretation of casing condition.

Acknowledgments

Thanks to the geothermal operators their assistance in obtaining photos and information and for the permission to publish the logs and well information.

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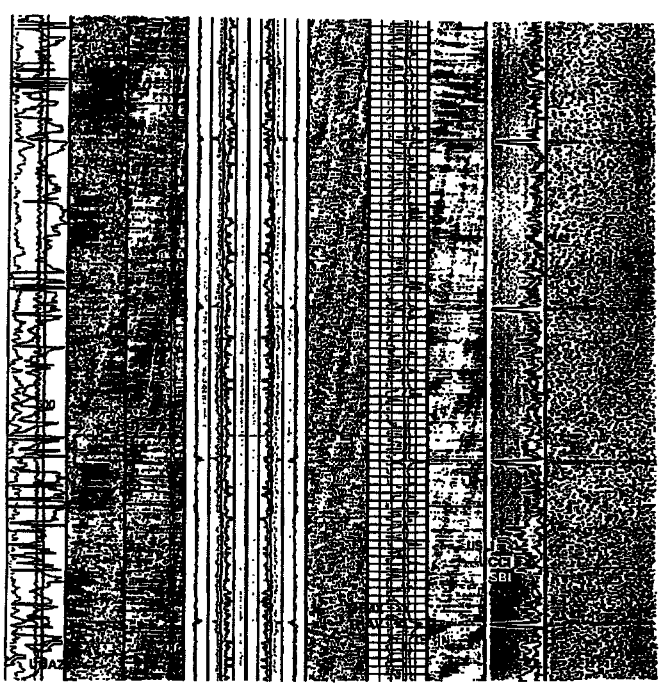

Figure 12. Log with heavy internal scale.

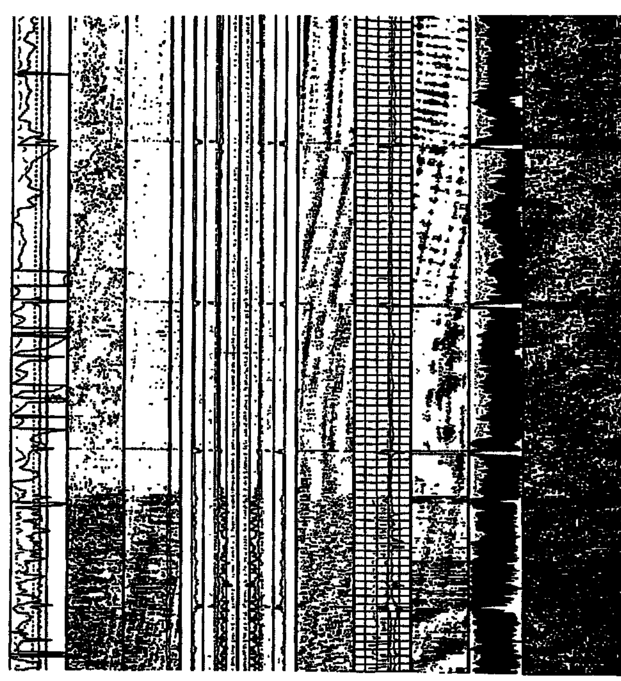

Figure 13. Same log as Figure 12 after acid clean out.

Ex. II - 12

Society of Petroleum Engineers IADC

IADC/SPE-180679-MS

Well Side-Track Optimization Using Electromagnetic and Ultrasonic Measurements Across Dual Strings for Well Integrity Assurance

Dhari M. Al-Saadi, Yousef A. Yateem, Shaikhah S. Omani, and Mohammad B. Al-Ajmi, Kuwait Oil Company; Mohamed AlMahdy and Yosra Abugreen, Schlumberger

This paper was prepared for presentation at the IADC/SPE Asia Pacific Drilling Technology Conference held in Singapore, 22–24 August 2016.

Abstract

This paper describes the application of a combined answer from Electromagnetic and Ultrasonic imaging measurements to assess the well integrity prior to well side track and Whip-Stock setting. This solution was applied in a very old well in Raudhatain field in Kuwait that was completed since 1959.

To optimize the cut depth for the side track across the single string, it was essential to identify an accurate depth of the external casing shoe, in addition to evaluation of both internal and external casings integrity and the cement bond quality for zonal isolation assurance. Data was acquired in September 2015 where the Electromagnetic log along with Ultrasonic images have been utilized with the advantage to provide answer in sections completed with dual strings for well integrity assessment.

The log results could detect the external casing shoe at the depth 7170-ft, presented good pipe integrity for the internal casing, and indicated good pipe condition with minor metal loss in the external casing across the double strings interval. The measured outer casing shoe was found 21-ft deeper than the theoretical from the old well sketch data, hence the depth of the well side track and Whip-Stock setting were optimized accordingly.

Failing to confirm the actual depth of the external casing shoe could have unintentionally led into drilling the side track across the double casing section resulting in undesirable workover operations and rig cost. Drilling a side track in dual pipe completed interval would also result-in damaging the outer casing and high remedial cost that cannot be predicted.

The operator "Kuwait Oil Company" has achieved their objective to side-track the well across single casing string without taking any risk and avoiding any implications through wireline technology and solutions.

INTRODUCTION

The Electromagnetic and Ultrasonic imaging measurements were acquired on Spetember 2015 in a very old well in Raudhatain field in Kuwait that was completed since 1959 and there was no enough information on accurate well completion sketch, cement or drilling mud data. The well is subject for cased hole side track drilling after evaluating the pipe and cement integrity.

The main objective was to assess the well integrity and optimize the cut depth prior to side track and Whip-Stock setting in the subject well by identifying an accurate depth of the external casing shoe of 9 5/8-in casing.

Electromagnatic measurements is planned to provide the pipe thickness across single and double casings interval that will confirm the outer casing shoe depth of 9 5/8-in and assess the casing integrity for both 7-in and 9 5/8-in pipes.

Ultrasonic measurement is planned in order to identify casing corrosion and loss of integrity, in addition to evaluate the cement to casing bond quality behind 7-in casing. Sonic measurement was also recorded to evaluate cement bond quality across the single casing section.

Following is a technical introduction on each acquisition technique implemented for this case study prior the discussion of results.

ELECTROMAGNATIC (EM) MEASUREMENT

"The EM casing inspection tool measures both internal and external corrosion. Its slim 2 1/8-in. diameter allows a deployment through tubing to quantitatively evaluate casing below the packer and in multiple casing strings or casing behind tubing by estimating the scale deposits and physical damage such as splits, holes, and partially collapsed sections.

This tool combines four types of EM measurements to assess tubular integrity:

- *EM metal thickness (ethick), an estimate of the average tubular metal thickness, using long-spacing low-frequency measurements for 2 7/8-in. through 13 3/8-in. casing outside diameter (OD)*
- *High-resolution image of total metal thickness, using low-frequency measurements on 18 radial arms for casings up to 9 5/8-in. OD*
- *High-resolution internal-defect image, using high-frequency measurements on 18 radial arms for casings up to 9 5/8-in. OD*
- *Casing inner diameter (ID), using closely spaced, high-frequency measurements"* (Taken from SPE 149069, Page 2, by Thilo Michael Brill et al).

EM inspection tool provides measurements to evaluate and identify corrosion in casing and tubing. The tool uses nondestructive induction methods to detect metal loss, pits, and holes, and it utilizes both Remote Field Eddy Current (RFEC) and High Frequency-Near Field Eddy Current (HF-NFEC) techniques. Refer to Figure 1.

The main applications and features of this techaniqe are:

1. Quantitative thickness evaluation of single casing
2. Qualitative thickness evaluation of multiple casing
3. Thickness image with discrimination in single casing
4. Pinpoint damage by depth and azimuth
5. Thru-tubing measurements
6. Operable in any down-hole fluid

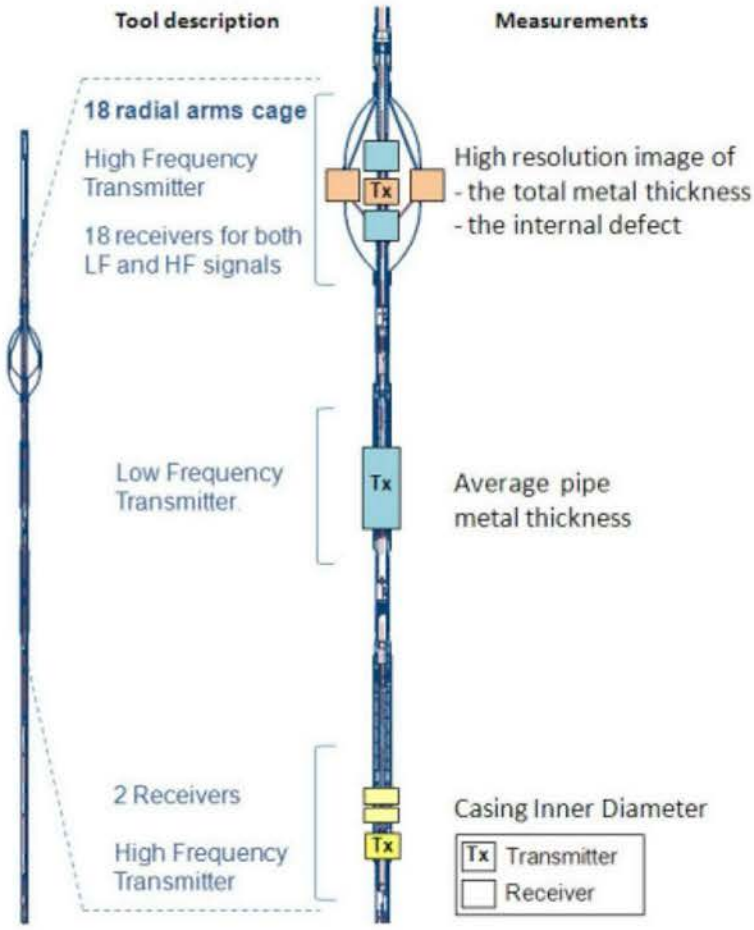

Figure 1—EM casing Inspection Tool (Taken from SPE 149069, Page 8, by Thilo Michael Brill et al.).

ULTRASONIC MEASUREMENT

The Ultrasonic imaging tool has a single rotating transducer that rotates at high speed (7+ rev/sec), and operates at high frequencies of between 200 and 700 kHz depending on casing thickness. This technique evaluates both casing integrity and cement bond around the entire circumference of the casing at a resolution of 1.2 inches across each depth. The ultrasonic signal processing will yield four measurements of the casing thickness, pipe internal radius, inner wall smoothness (from the initial echo amplitude and time), and the acoustic impedance of materials in the annulus (from the signal resonance decay). Refer to Figure 2.

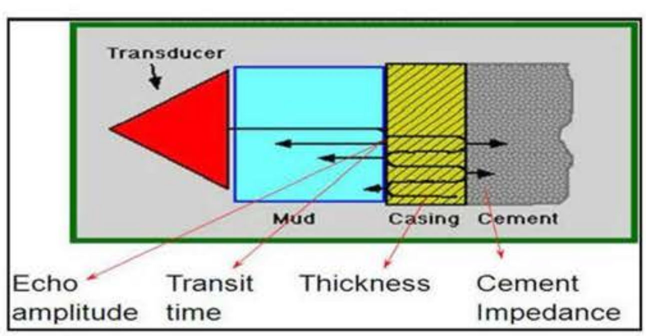

Figure 2—Ultrasonic tool principle of measurement

The acoustic impedance of any material is the product of its density by the sound velocity through it (Z=density x acoustic velocity). Z is usually expressed in MRayl (106 $kg.m^{-2}{\cdot}s^{-1}$). Empirical cutoffs or thresholds are used to determine solids, liquid, or gas. The default value of the threshold between liquid and solid is 2.6 MRayls, and between liquid and gas is 0.3 MRayls, as illustrated in Figure 3.

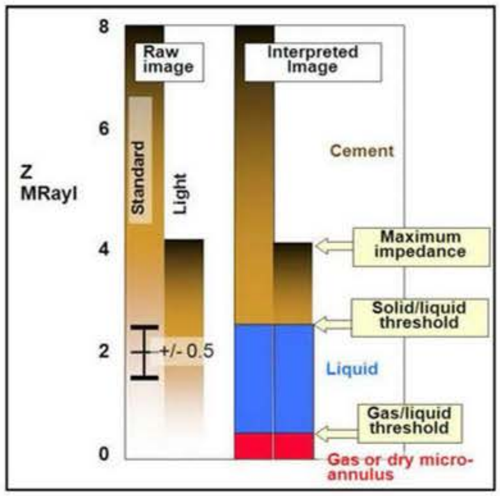

Figure 3—Empirical threshold of measured acoustic impedance to discriminate solid-liquid-gas

SONIC MEASUREMENT

The ″CBL″ or cement bond log has been around since the 1960’s. It is based on the principle that a signal transmitted through a casing unsupported by cement will ring strongly and attenuate slowly while that same signal will ring weakly and attenuate quickly when transmitted through a casing well supported by cement.

This measurement is omni-directional, responding to the average of contributions from around the circumference of the casing, and is made at a relatively low frequency of ~ 20 kHz at a transmitter-to-receiver spacing of 1 to 3 feet. The measurement is normally accompanied by a variable density log (VDL) that is made at a longer transmitter-to-receiver spacing of 5 feet (Figure 4). This VDL may yield an indication of cement bond to the formation.

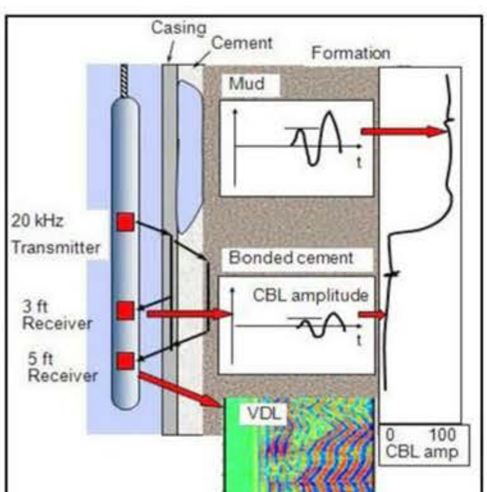

Figure 4—Sonic tool principle of operation

The CBL measurement has some strengths that have allowed it to stand the test of time. It is still used today for cement evaluation, either independently or in combination with an ultrasonic measurement. The measurement responds well to solidity, works well in most fluids, is unaffected by internal casing condition and provides an indication of cement-formation bond. Latest generation tools also include mapping features that can indicate broad channels.

The CBL is sensitive to fast formation, and extremely sensitive to both eccentering and liquid microannulus. The omni-directional nature of the measurement and the low frequency at which it is taken also render the CBL ineffective in identifying channels or contaminated cements.

CBL/VDL tool is not designed to work in dual completion environment, in which the received signal will be affected by all casing resonance, hence cannot be interpreted to provide cement bond evaluation across multiple strings.

CASE STUDY

The well was completed with 7-in, 26 ppf casing from surface till 8645.5 ft and the outer 9 5/8-in, 43.5 ppf that was reported to be set from 5729.3 ft to 7149 ft as per the old well sketch. To inspect the 9 5/-in casing condition with the 7-in casing in place, the Electromagnetic Imaging Tool was used in combination with the ultrasonic to achieve this objective. The logging interval extends from 6500 ft to 7500 ft.

The Electormagnatic data, using its deep reading Low Frequency Remote Field Eddy Current measurement (RFEC), is able to provide a reliable "Total" wall thickness indicator in inches. Note that the EMIT reads an average pipe thickness and has no azimuthal resolution. The double casing string (7-in and 9 5/8-in) extending above 7170 ft. The outer casing thickness is then computed by subtracting the inner casing pseudo thickness from the total thickness.

The percentages of average metal loss are computed based on the fraction of measured minimum and average thickness of each joint, with reference to nominal casing wall thickness.

ACQUISITION RESULTS

The log analysis was divided in two sections as following:

1. Single casing string (i.e. 7-in casing section extending from 7500 ft to 7170 ft). Log results show that casing is in overall good condition. The average metal loss calculated translates to less than 5% across this section suggesting no severe anomaly or casing damage.
   Overall it shows a reasonable consistency with the USIT findings from both inner radii and thickness readings.
2. Double casing string (i.e. 7-in × 9 5/8-in casing section extending from 7170 ft to 6500 ft). The total thickness of (7-in and 9 5/8-in) casings, as measured by EMIT, shows that both pipes are in good condition except for the possibility of some minor metal loss in the outer casing between depths 6527-6584 ft and 6851-6869.5 ft where thickness is reading slightly lower values than total nominal casing thickness.
   The percentages of metal loss are computed based on the fraction of measured minimum and average thickness of each joint, with reference to nominal casing wall thickness.

Refer to Figure 5 for the Statistical Analysis for Single & Double Casing Strings from EMIT.

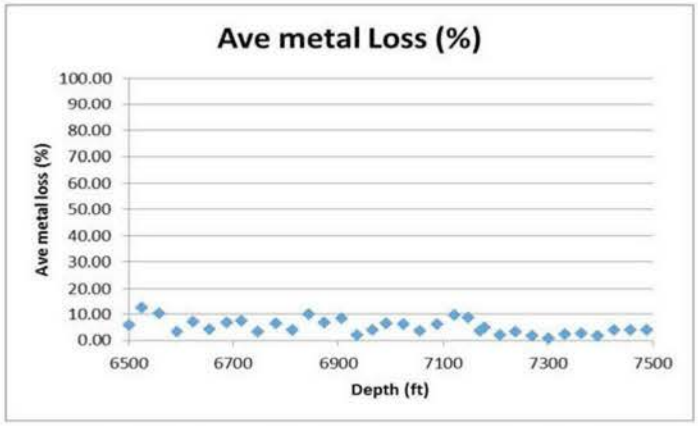

Figure 5—EMIT estimated average metal loss%

Electromagnatic measurements could detect the presence of 9.625-in casing shoe at 7170 ft that was also suggested from the Ultrasonic log. Comnined answer from sonic and ultrasonic indocated fair presence of cement in the annulus across the single and double strings. Refer to Figure 6.

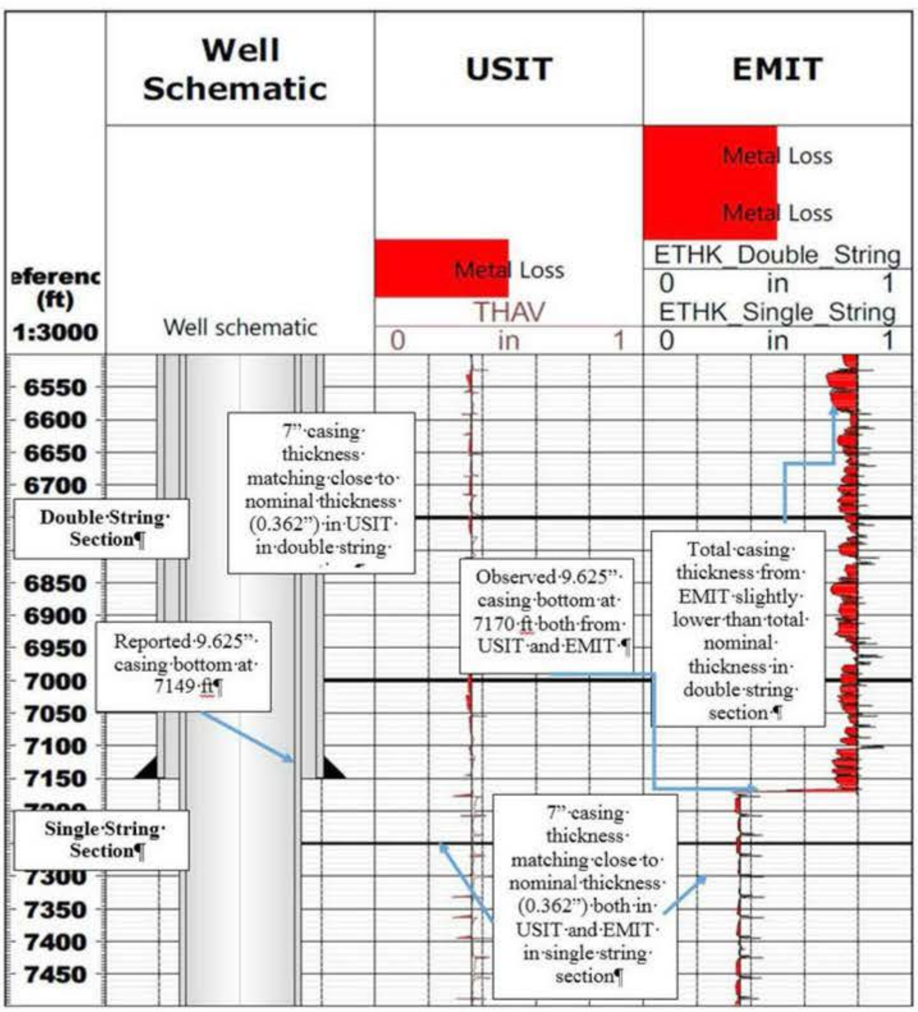

Figure 6—Casing evaluation summary

CONCLUSION

Ultrasonic and sonic measurements could present fair cement presence in the annulus behind the 7-in casing in single and double strings with good pipe integrity. Electromagnetic log analysis indicated both strings of 7-in and 9 5/8-in casings in good condition with no serious metal loss and detected the outer casing shoe depth at 7170 ft.

The measured outer casing shoe was found 21-ft deeper than the theoretical as reported in the old well sketch data, hence the depth of the well side track and Whip-Stock setting were optimized accordingly.

Failing to confirm the actual depth of the external casing shoe could have unintentionally led into drilling the side track across the double casing section resulting in undesirable workover operations and rig cost. Drilling a side track in dual pipe completed interval would also result-in damaging the outer casing and high remedial cost that cannot be predicted.

The operator "Kuwait Oil Company" has achieved their objective to side-track the well across single casing string without taking any risk and avoiding any implications through WL provided technology and solutions.

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Ex. II - 13

SPE 156052

An Integrated Approach to Well Integrity Evaluation via Reliability Assessment of Well Integrity Tools and Methods: Results from Dukhan Field, Qatar

Sanjay K Singh, Herry Subekti, Mona Al-Asmakh, Layth Al-Samarraie, Qatar Petroleum

This paper was prepared for presentation at the SPE International Production and Operations Conference and Exhibition held in Doha Qatar, 14–16 May 2012.

Abstract

Qatar Petroleum's super-giant Dukhan field located onshore Qatar has a mature inventory of hundreds of wells. Managing integrity of such mature well inventory to avoid unplanned downtime has been no less crucial than any other activity to maximizing production and injection. This involves costly wellwork decisions for integrity control and repair, which rely heavily on data obtained from a well integrity monitoring program. Well integrity monitoring program ranges from using basic methods to state-of-the-art downhole monitoring tools. Their applications are almost always associated with limitations that impose uncertainty in well integrity evaluation. This paper presents an integrated approach Qatar Petroleum used to address this issue. This approach consisted of performing reliability assessment of the entire array of available tools and methods against given well conditions with a matrix of assessment criteria. This matrix enabled selection of a fit-for-purpose set of tools and methods with clear understanding of their strengths and limitations. Techniques of correlation, bracketing and elimination were then applied to analyze the outputs obtained from using the selected set of tools and methods. The approach allowed detecting well integrity problems and determining their severity with minimal uncertainty. The paper focuses on intricacies of the approach, and how its implementation results in a sound well integrity evaluation. It also presents field examples that demonstrate efficacy of the approach in supporting costly wellwork decisions for restoring well integrity. Successfully restoring the well integrity unlocked revenue potential, made quick payout of the wellwork costs and extended the field life.

Introduction

Dukhan field is located onshore Qatar approximately 80 km to west of Doha, the capital of the state of Qatar. The field has a mature inventory of a large number of wells. Qatar Petroleum (QP) manages integrity of such wells via its established well integrity monitoring and remedial wellwork programs. Data obtained from the monitoring program are used for integrity evaluation that in turn leads to deciding the requirement and type of wellwork for integrity control and repair. Majority of the wellwork decisions are cost-intensive and a sound integrity evaluation is key to their success.

One of the most popular definitions of well integrity, as provided in NORSOK D-010, is "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". Application of the solutions mentioned in this definition basically aim at preventing, detecting and repairing integrity problems. QP's well integrity monitoring program focuses on preventing and detecting a wide range of potential integrity problems that can occur in surface and downhole components of a well. An array of techniques involving basic methods to state-of-the-art downhole tools is used. Each of the methods and tools has its own strengths as well as limitations. Limitations of methods and tools have the potential of imposing uncertainty in well integrity evaluation. An integrated approach has been developed to address this issue. Subsequent sections of this paper discuss intricacies of this approach and present some field examples to show how implementation of the approach resulted in sound well integrity evaluation.

The Approach

The approach consists of the following steps:

1. Setting reliability matrices for methods and tools
2. Prognosticating the range of possible well integrity problems
3. Using the reliability matrices for selection of a fit-for-purpose set of tools and methods

4. Evaluating outputs with correlation, elimination and bracketing techniques
5. Identifying well integrity problems

1. Setting reliability matrices for methods and tools

Reliability matrices have been set up separately for surface methods and downhole tools in investigating various well integrity elements. Surface methods comprise wellhead pressure monitoring, fluid sampling & pressure testing. Downhole tools include a range of logging tools used for wellbore and behind-casing inspection. Well integrity elements range from wellhead or near surface to downhole and behind casing elements. Table-1 and 2 present reliability matrices summarizing reliability of each of the methods and tools as 'good', 'fair' or 'poor' in investigating the well integrity elements. An elaboration on how the reliabilities were defined is given below.

Surface Methods

Wellhead Pressure Monitoring & Produced Fluid Sampling

Fluctuations in wellhead pressure coupled with abrupt change in well rate may be indicative of downhole casing and tubing/ packer leak. Continuous analysis of wellhead pressure data to identify such anomaly helps in early detection of downhole leaks and taking a suitable action to prevent charging of shallow aquifers with either hydrocarbons or injected water.

Wellhead produced fluid sampling with well test data forms an important input to the above analysis. For example, if the water-cut and GOR haven't changed and there is sudden drop or significant fluctuation in wellhead pressure, it could be a strong indication of downhole leak that need confirmation by running appropriate downhole tools.

However, it is recognized that in several cases, downhole casing & tubing/ packer leaks may not present any noticeable anomaly in wellhead pressure and fluid. Hence reliability of wellhead pressure monitoring & fluid sampling in determining downhole leak is considered '**fair to poor'**.

Annuli Pressure Monitoring & Effluent Sampling

Procedures for drilling and completing wells are designed such that no pressure should be seen on any one of the annuli during the well's operation phase. The exceptions are wells on gaslift, where pressure in annulus between tubing and production casing is due to lift gas pressure or the wells without packer. Thermal expansion of tubing, casing or packer fluid when the well is first placed on production may also cause pressures to build up in one or more of the annuli; however these pressures should not recur once they are bled off and the well is in normal production mode.

Pressure in cemented annuli between two casings develops due to one or more of the following factors:

- Cement channelling
- Incomplete cement circulation
- Casing leak(s)
- Leak through wellhead seal(s)

Pressure in annulus between tubing and production/ injection casing develops due to one or more of the following factors:

- Production/ injection casing leak
- Tubing or packer leak(s)
- Tubing bonnet and hanger pack-off leak

There are multiple factors as mentioned above that can cause annuli pressures. Hence reliability of annuli pressure monitoring and effluent sampling is considered **'fair'** in determining presence of either or a combination of such factors, but '**poor'** in finding which one of these factors is the unique cause.

Pressure Testing of Wellhead Seals

Pressure testing of wellhead seals is a direct and conclusive method to ascertain wellhead seals integrity with '**good**' reliability.

Pressure Testing of Tubing & Production/ Injection Casing

Successful pressure testing of tubing (with plug installed at bottom of the tubing string and dummies in gas lift mandrels, if any) & production/ injection casing establishes integrity of wellhead seals, production/ injection casing and packer. If during successful pressure testing of tubing string, no pressure is seen on tubing – casing annulus, integrity of tubing string is also established. However an unsuccessful pressure test could be due to integrity failure of any or a combination of these components or a leak through the tubing plug or gas lift mandrel. Hence reliability of pressure testing in determining casing, tubing or packer integrity is considered **'fair'**.

Annuli Pressure Testing

Annuli pressure testing consists of:

- Testing the annuli between casings in a recommended sequence
- Analyzing results to diagnose the cause of annuli leak
- Identifying the need for remedial cement top-up or securing well for further action such as workover or abandonment.

Annuli pressure test are performed after pressure testing of wellhead seals has ruled out wellhead communication. An unsuccessful annuli pressure test without having performed pressure testing of wellhead seals could be due to either wellhead communication or cemented annulus or both. Hence reliability of annuli pressure testing in determining wellhead seal integrity is considered **'fair'.**

Annuli pressure test is effective in determining whether a cemented annulus isolates downhole pressure zones (hydrocarbon or aquifer) from surface. However, it is inconclusive in detecting cement channels or voids that might be present in the annulus causing isolation failure between two zones. This is because presence of a cement bridge could mask such channels or voids from surface. Hence reliability of annuli pressure testing in determining wellhead seal integrity is considered **'fair to poor'**.

Surface Casing & Casing Head Inspection

Near surface external corrosion (i.e. corrosion on casing head housing and portion of surface casing just below ground) is caused by cyclic or consistent ingress of oxygenated surface water or moisture in the annular space between the conductor pipe and surface casing. The retained oxygenated water in the annulus leaches out chemical salts from the cement and at elevated well operating temperatures (around 120 deg F) creates low resistance electrolyte resulting in an extremely corrosive environment. Additionally, the cement micro annulus that emanates behind the surface casing tends to retain small amount of water which also cause slow but steady development of near-surface corrosion on the surface casing.

Downhole Tools

Temperature & Flowmeter Logs

Static temperature profiling is the primary means to finding downhole casing leaks and static temperature surveys usually are required first after a well's initial completion or re-completion to generate a base temperature profile. Thereafter, it is needed at pre-determined intervals and results are compared with base temperature profile to detect any anomaly.

Casing leak & resultant cross-flow via wellbore is detected easily and with **'good'** reliability from the anomalies detected on the static temperature profile. Flowmeter surveys are normally required to confirm a downhole casing leak (detected from temperature survey or otherwise) and quantify the cross-flow rate. It should be conducted based on a specific requirement (such as indicated by static temperature anomaly) and after considering downhole completion to decide whether or not it will provide any useful result.

Temperature anomalies could also be due to fluid movement through cement channels behind casing and their analysis should be done in correlation with other information such as quality of cementation, stratigraphic and petrophysical information. Some cases of fluid flow through cement channels behind casing may not be convincingly detected by temperature anomalies particularly when the cross-sectional area of the channel compared to the wellbore is very small. In such cases, running a noise or ultrasonic log can supplement temperature anomalies to detect behind-casing flow. Hence, reliability of temperature logs in detecting cross-flow behind production/ injection casing is just about **'fair'**.

Multi-fingered Calipers

Multi-fingered callipers are well-established tools to evaluate production / injection casing internal corrosion with **'good'** reliability. They provide no data about external corrosion though and are affected by scale build-up on inner wall of the casing.

Ultrasonic Pipe Imaging Tool

Ultrasonic pipe imaging tools yield excellent pipe thickness information with superior azimuthal resolution in a single casing. Pipe thickness coupled with internal radii measurements makes reliability of this tool '**fair**' in determining internal and external corrosion of Production/ Injection casing. However, they are unable to operate in gas wells, through tight restrictions and their measurements can be disrupted by pipe roughness and excessive corrosion.

Electromagnetic Pipe Imaging Tool™

Electromagnetic pipe imaging tools measure gross metal thickness around it and hence are able to examine both internal & external corrosion in multiple casing strings. Correlating their measurements with ultrasonic measurement of single casing thickness helps determine whether outer casings are corroded. These tools provide electromagnetic flux leakage based measurements and therefore are good at measuring sudden thickness changes rather than constant or gradual variation of thickness over a whole section of pipe. It can operate in any fluid and has excellent vertical resolution. Azimuthal resolution is not as high as that of ultrasonic measurements and small holes can go unnoticed. Hence reliability of electromagnetic imaging tools in determining corrosion of multiple casing strings is considered **'fair'**.

Downhole Camera

Downhole camera requires the wellbore to be filled with clean fluid or gas for detecting internal corrosion and hence, its reliability is considered **'fair'**.

Cement Bond Log

Cement Bong Log (CBL) with Variable Density Log (VDL) gives an overall idea about cement to casing & cement to formation bond. Lack of azimuthal coverage renders reliability of this tool to be **'fair'** in determining production/ injection casing cement isolation.

Ultrasonic Cement Imaging Tool

Ultrasonic cement imaging tool provides azimuthal image of cement around the casing and a detailed map of solid cement, liquid & gas filled annuli/ voids and micro-debonded cement. Its reliability in determining production/ injection casing cement isolation is considered **'good'**.

2. Prognosticating the range of possible well integrity problems

Review of well construction and operation history and previous experiences enables predicting possible well integrity problems. For example, an incomplete cement circulation during cementing could point towards such problems as the presence of cement micro-annuli, casing external corrosion, casing leak and zonal cross-flow. A previously recorded onset of corrosion in a downhole tubular with no mitigation undertaken over a time lapse could point towards the integrity failure of the downhole tubular. In addition, if experience in some other well(s) recorded failure of wellhead similar of similar material & type, then wellhead seal failure in the well being evaluated is also likely.

3. Using reliability matrices

Relating the prognosticated range of integrity problems to reliability matrices enables selecting a fit-for-purpose set of methods & tools for integrity evaluation. The matrices provide a technical basis for making such selection reasonable and avoiding running a tool which could add to the cost with little value. For example, temperature log's reliability in detecting zonal cross-flow via wellbore is **'good'**. Hence, if static temperature profile establishes such cross-flow in a well, running downhole camera will add little value to enhancing the reliability of this finding. Flowmeter however can be considered to determine the cross-flow rate, if required.

4. Evaluating outputs with correlation, elimination and bracketing techniques

Correlation, bracketing and elimination are mathematical techniques that are implicitly applied during qualitative assessment of outputs received from the applied set of methods and tools for well integrity evaluation.

Correlation means comparing and analyzing well integrity data obtained from more than one method or tool to determine similar, dissimilar or overlapping problem areas they relate to. Elimination is finding the data that relate to an overlapping problem area. Bracketing implies extracting dissimilar or non-overlapping problem areas and determining their uncertainty-band. Application of these techniques enables focused assessment of problem areas while making best use of outputs from the applied methods and tools.

5. Identifying well integrity problems

Systematic application of the above steps enables identifying well integrity problem(s) with reasonable confidence. This helps determine type of repair wellwork required to resolve the problem. Prioritization of repair wellwork is done based on relative severity of integrity problem(s). QP uses a comprehensive technique to assess problem severity and consequential impact. Discussion on such technique is beyond the scope of this paper, and will be presented in a separate paper in future.

Field Examples

Typical well construction design in Dukhan field consists of 13-3/8" surface casing, 9-5/8" intermediate casing & 7" production casing. All casing strings are cemented up to surface through either single or dual stage primary cementing jobs. Examples below show how the approach discussed above was applied in the field for well integrity evaluation.

Well No. 1 (Oil Producer)

Prognosticating the range of possible well integrity problems

Primary cementation of 13-3/8" was incomplete because of losses into highly porous shallow aquifer. The 7" and 9-5/8" casings were cemented successfully. The 13-3/8" and 9-5/8" casings in the well covered the porous shallow aquifer, which is also corrosive. The well was completed as a perforated oil producer and continued oil production for a period of over 20 years. Towards the end of this period, the well started showing a sustained annulus pressure in 7" x 9-5/8" casing annulus.

Based on the above information, the following possible well integrity problems were prognosticated initially for evaluation:

- Loss of wellhead seal integrity
- Zonal cross-flow via wellbore or behind 7" production casing
- Loss of cement integrity in 7" x 9-5/8" casing annulus
- External corrosion of casings due to possible contact with corrosive aquifers

Using the reliability matrices for selection of a fit-for-purpose set of tools and methods

For determining wellhead seal integrity, the method of pressure testing of wellhead seals has **'good'** reliability based on reliability matrix and hence, was used. It showed wellhead communication. Rigless attempts to eliminate wellhead communication were unsuccessful.

For investigating the possibility of zonal cross-flow via wellbore, temperature log has **'good'** reliability based on reliability matrix. It also has **'fair'** reliability in investigating zonal cross-flow behind 7" production casing. Results of static temperature log run in the well ruled out the possibility of zonal cross-flow via wellbore. It however presented some anomaly across 1600-1800 ft (Figure-1), which could not be conclusively interpreted because of unavailability of base-line static temperature profile.

For checking cement integrity in 7” x 9-5/8” casing annulus, the method of annuli pressure testing has ‘**fair/poor’** reliability. 7” casing could not be pressure tested due to packerless completion. Pressure testing 7” x 9-5/8” casing annulus without successful pressure testing of 7” casing integrity has the risk of creating wellbore – annulus communication. Hence, annuli pressure testing was not performed.

Failure of rigless attempts to eliminate wellhead communication as well as presence of anomaly on temperature log necessitated to workover the well. It was decided to investigate casing and cement integrity during the workover.

Ultrasonic pipe imaging tool and electromagnetic pipe imaging tool have **‘fair’** reliability for investigating production casing corrosion and outer casings corrosion respectively. It was decided to run both tools in the well after pulling out completion string during the workover. Moreover, it was decided to run ultrasonic cement imaging tool for investigating cement integrity in 7” x 9-5/8” casing annulus since this tool has **‘good’** reliability for such purpose.

Outputs were evaluated with correlation, elimination and bracketing techniques to reach conclusions.

Evaluating outputs with correlation, elimination and bracketing techniques

Output of electromagnetic imaging tool showed a section of anomaly across 210 – 250 ft (Figure-2). The gross thickness measured by this tool was correlated with the thickness measured by ultrasonic imaging tool over this section. Output of ultrasonic imaging tool showed 7” casing thickness around 0.3” with no significant metal loss. Output of electromagnetic imaging tool showed remaining gross thickness of 3 casings (7”, 9-5/8” & 13-3/8”) around 0.7” against the original of around 1.0”.

Similar or overlapping data between the two measurements was the thickness of 7” casing i.e. 0.3”. Eliminating this thickness from the gross thickness bracketed the remaining thickness of outer 2 casings (9-5/8” and 13-3/8”) at around 0.4” over the section of anomaly. Uncertainty-band of this bracket ranged from a remaining thickness 0.2” of each casing to 0.4” of either casing.

This uncertainty-band was further analyzed and resolved as following:

- 7” casing didn’t show any sign of internal corrosion. Hence, the entire metal loss could be attributed to external corrosion caused by corrosive aquifer.
- Corrosive aquifer acts first on outermost 13-3/8” casing. Hence, external corrosion on 9-5/8” casing cannot start unless 13-3/8” remaining thickness reduces to zero. This implies that since the remaining thickness of outer 2 casings (0.4”) is more than the thickness of 13-3/8” casing (0.35”), 9-5/8” casing didn’t suffer from metal loss.

Identifying well integrity problems

Application of the above techniques established the integrity of 7” & 9-5/8” casings across corrosive aquifer and confirmed that the entire metal loss took place on 13-3/8” casing. Anomaly seen on static temperature log across 1600 – 1800 ft (Figure 1) was examined with output of ultrasonic pipe & cement imaging tools and no casing and cement integrity problem was detected (Figure-3).This helped salvaging and completing the well for production.

Well No. 2 (Water Injector)

Prognosticating the range of possible well integrity problems

9-5/8” casing was cemented in 2 stages with incomplete cementation in 1st stage because of downhole problem. 7” casing was cemented in 2 stages with complete & successful cementation in both stages. Incompletely cemented section of 9-5/8” casing in the well covered a corrosive aquifer.

Based on the above information, the following possible well integrity problems were prognosticated initially for evaluation:

- Loss of cement integrity in 9-5/8” x 13-3/8” casing annulus
- External corrosion of casings due to possible contact with corrosive aquifer

Using the reliability matrices for selection of a fit-for-purpose set of tools and methods

For checking cement integrity in 9-5/8” x 13-3/8” casing annulus, the method of annuli pressure testing has **‘fair/poor’** reliability based on reliability matrix. Hence, even though pressure testing of this annulus was successful, it didn’t conclusively establish the cement integrity.

Workover of the well for reservoir management reason was used as an opportunity to investigate external corrosion of casings and cement integrity in 7” x 9-5/8” casing annulus. Ultrasonic pipe imaging tool and electromagnetic pipe imaging tool have **‘fair’** reliability for investigating injection casing corrosion and outer casings corrosion respectively. It was decided to run both tools in the well after pulling out completion string during the workover. Moreover, it was decided to run ultrasonic cement imaging tool for investigating cement integrity since this tool has **‘good’** reliability for such purpose.

Evaluating outputs with correlation, elimination and bracketing techniques

Output of electromagnetic imaging tool showed a section of anomaly across 3510 – 3530 ft (Figure-4). The gross thickness measured by this tool was correlated with the thickness measured by ultrasonic imaging tool over this section.

Output of ultrasonic imaging tool showed minor external corrosion in 7” casing with remaining thickness of 0.25” against original thickness of 0.3”. Output of electromagnetic imaging tool showed remaining gross thickness of 3 casings (7”, 9-5/8” & 13-3/8”) around 0.25” against the original of around 1.0”.

Similar or overlapping data between the two measurements was the thickness of 7” casing i.e. 0.25”. Eliminating this thickness from the gross thickness bracketed the remaining thickness of outer 2 casings (9-5/8” and 13-3/8”) to zero. This showed majority of the metal loss tool place in the outer 2 casings and they lost their integrity while 7” casing still retained most of its metal thickness.

Identifying well integrity problems

Application of the above techniques established the integrity of 7” casing. Output of ultrasonic cement imaging tool confirmed cement integrity (Figure-5).

Based on above evaluation, 5” casing was run and cemented inside 7” casing to enhance casing barrier against corrosive aquifer and salvage the well for injection.

Conclusions

Well integrity evaluation is an inexact science, reasonably matured yet imperfect. Several methods and tools have been in use with their relative strengths and limitations. The integrated approach used for well integrity evaluation includes selecting a fit-for-purpose set of methods and tools via reliability matrices and analyzing their outputs with correlation, bracketing and elimination techniques. The approach allowed detecting well integrity problems with increased confidence and supported costly wellwork decisions to restore well integrity. Successfully restoring the well integrity unlocked revenue potential, made quick payout of the wellwork costs and extended the field life.

Acknowledgements

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3. Julian, J. Y. *et al.*: ‘Detecting Ultra-small Leaks with Ultrasonic Leak Detection – Case Histories From the North Slope, Alaska’, paper SPE 108906 presented at International Oil Conference and Exhibition, Veracruz, Mexico, June 27-30, 2007.

Tables

Table – 1: Reliability Matrix for Surface Methods

Integrity Element	Reliability (Good / Fair / Poor)					
	Wellhead Pressure Monitoring & Produced Fluid Sampling	**Annuli Pressure Monitoring & Effluent Sampling**	**Pressure Testing of Wellhead Seals**	**Pressure Testing of Tubing & Production/ Injection Casing**	**Annuli Pressure Testing**	**Surface Casing & Casinghead Inspection**
Wellhead seal Integrity	---	Fair/ Poor	Good	---	Fair	---
Near surface external corrosion of surface casing	---	---	---	---	---	Good
Production/ injection casing integrity	Fair/ Poor	Fair/ Poor	---	Fair	---	---
Tubing/ packer integrity	Fair/ Poor	Fair/ Poor	---	Fair	---	
Annuli cement integrity	---	Fair/ Poor	---	---	Fair/ Poor	---

Table – 2: Reliability Matrix for Downhole Tools/ Techniques

<table>
<tr><th rowspan="2">Integrity Element</th><th colspan="7">Reliability (Good / Fair / Poor)</th></tr>
<tr><th>Temperature & Flowmeter Log</th><th>Multi-fingered Calipers</th><th>Ultrasonic Pipe Imaging Tool</th><th>Electro-magnetic Pipe Imaging Tool</th><th>Downhole Camera</th><th>Cement Bond Log</th><th>Ultrasonic Cement Imaging Tool</th></tr>
<tr><td>Zonal cross-flow via wellbore</td><td>Good</td><td>---</td><td>---</td><td>---</td><td>Fair</td><td>---</td><td>---</td></tr>
<tr><td>Zonal cross-flow behind production/ injection casing</td><td>Fair</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td></tr>
<tr><td>Production/ Injection casing internal corrosion</td><td>---</td><td>Good</td><td>Fair</td><td>---</td><td>Fair</td><td>---</td><td>---</td></tr>
<tr><td>Production/ Injection casing external corrosion</td><td>---</td><td>---</td><td>Fair</td><td rowspan="2">Fair</td><td>---</td><td>---</td><td>---</td></tr>
<tr><td>Outer casings corrosion</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td></tr>
<tr><td>Production/ Injection casing cement integrity</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td><td>Fair</td><td>Good</td></tr>
<tr><td>Outer casings cement integrity</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td><td>---</td></tr>
</table>

Figures

Figure-1: Well No.1 – Output of Temparature Log

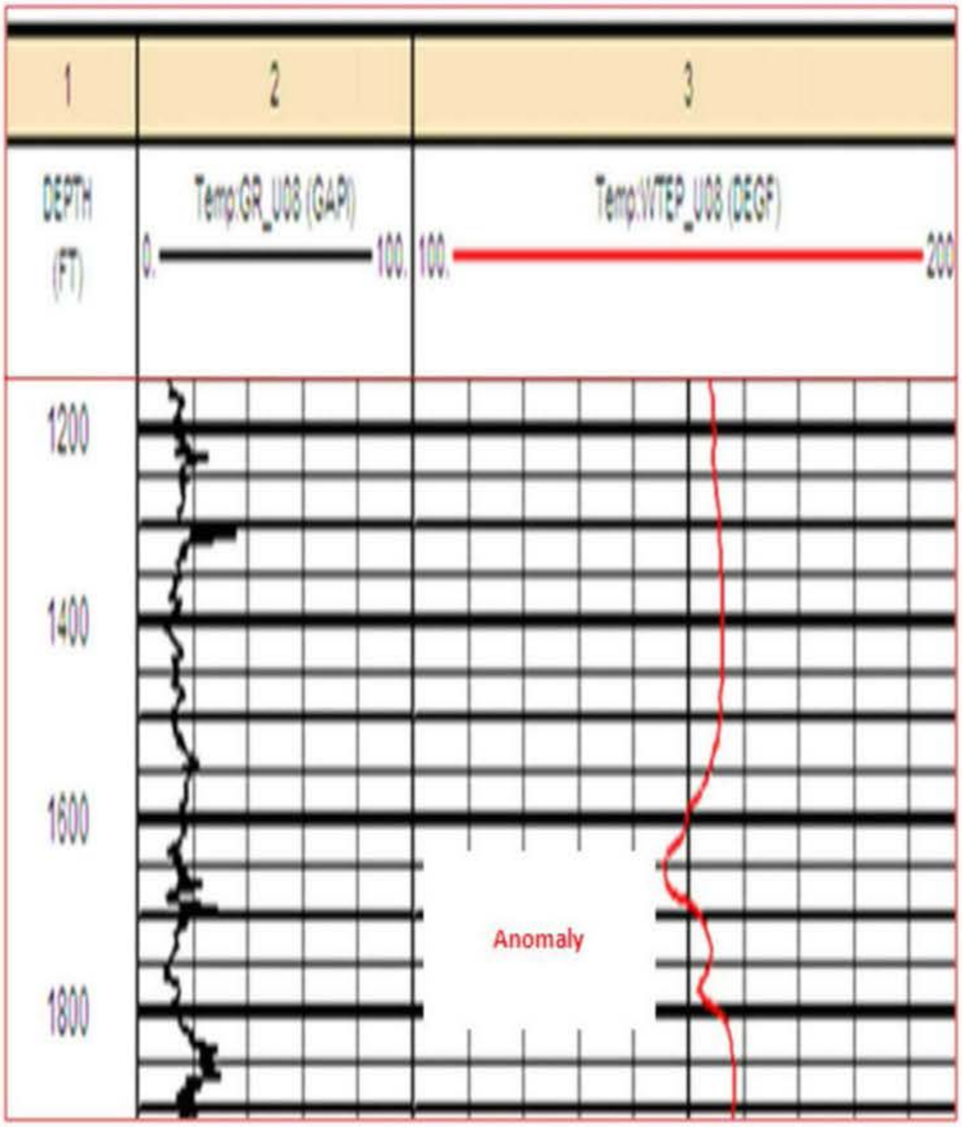


Figure-2: Well No.1 – Output of Ultrasonic & Electromagnetic Pipe Imaging Tools

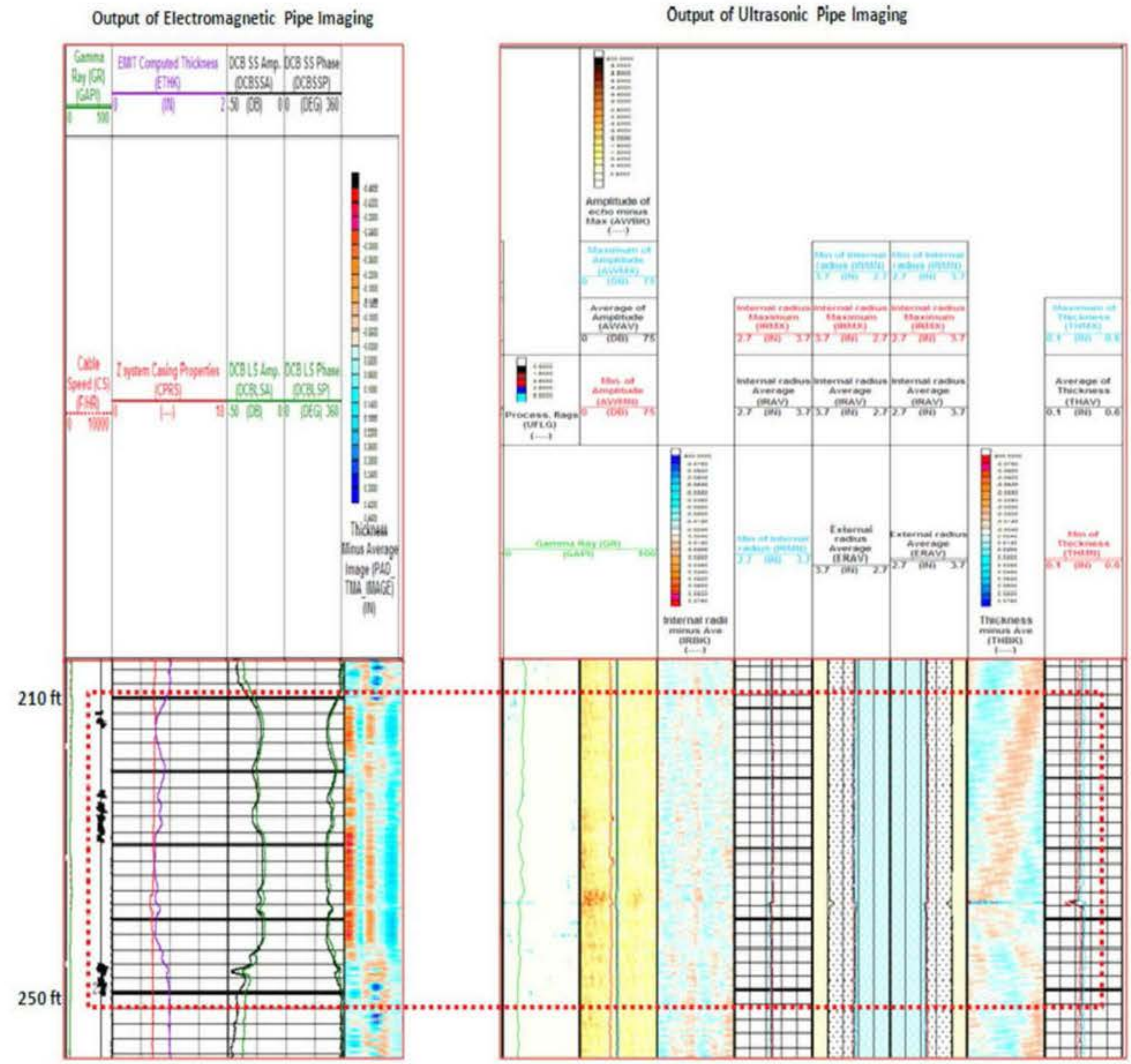


Figure-3: Well No.1 – Output of Ultrasonic Pipe & Cement Imaging Tools

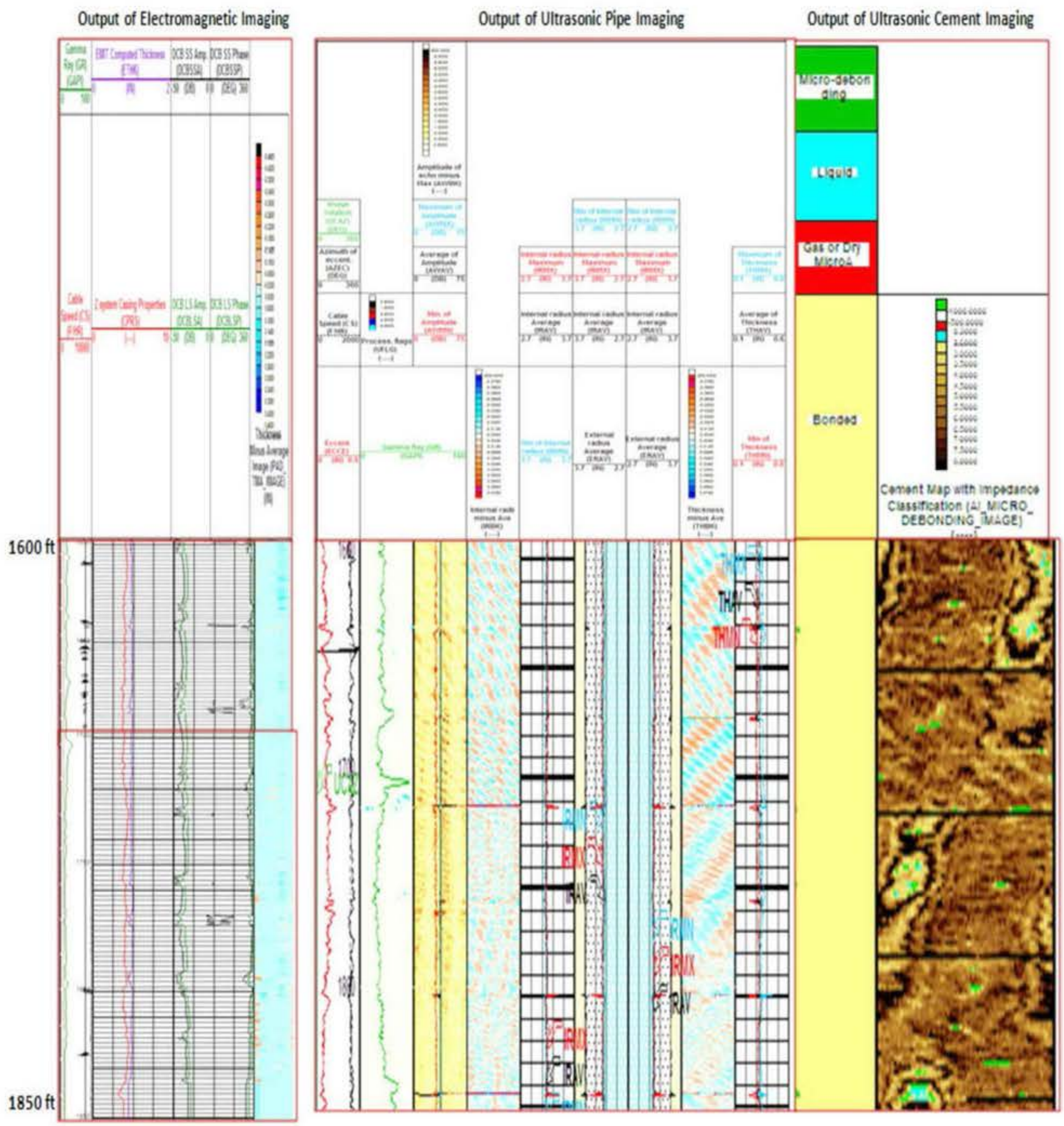


Figure-4: Well No.2 – Output of Ultrasonic & Electromagnetic Pipe Imaging Tools

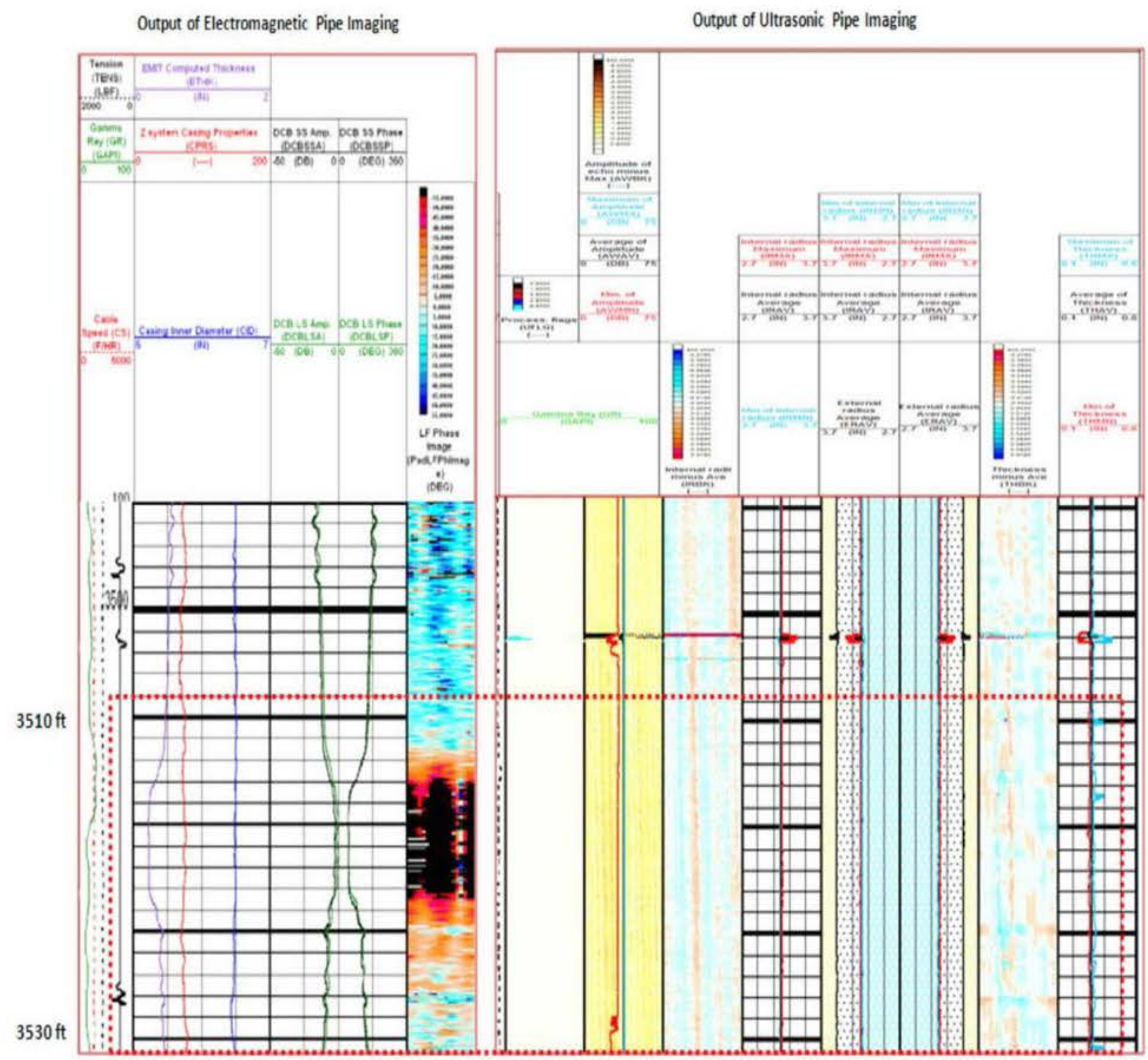
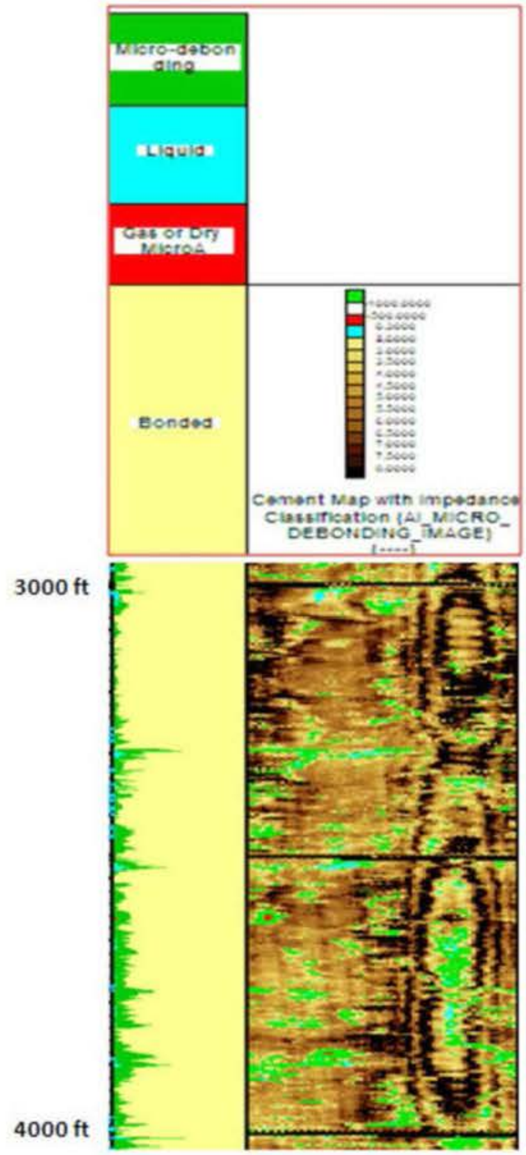


Figure-5: Well No.2 – Output of Ultrasonic Cement Imaging Tools



Ex. II - 14

VERTILOG®

Western Atlas International
A Litton/Dresser Company

CUSTOMER	SOUTHERN CALIFORNIA GAS CO.	WORK ORDER NO.	124303	DATE	12-16-88
LEASE/WELL NO.	STANDARD SESNON No. 9	CUSTOMER ORDER NO.			
FIELD	ALISO CANYON	COUNTY	LOS ANGELES	STATE	CALIFORNIA
CASING O.D.	7" WEIGHT(S) 23,26,29	NOMINAL WALL THICKNESS		GRADE	J-55, N-80
TOTAL FOOTAGE INSPECTED	8553'	FROM	SURFACE	TO	8553' DEPTH

SUBSURFACE CASING INSPECTION REPORT

SUMMARY

198 LENGTHS WERE FOUND TO SHOW NO EVIDENCE OF CORROSION EXCEEDING 20 PERCENT OF THE NOMINAL BODY WALL. CLASS 1

6 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 20 PERCENT BUT LESS THAN PERCENT OF THE NOMINAL BODY WALL. CLASS 2

0 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 40 PERCENT BUT LESS THAN PERCENT OF THE NOMINAL BODY WALL. CLASS 3

0 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 60 PERCENT OF THE NOMINAL BODY WALL. CLASS 4

204 TOTAL LENGTHS

8553' TOTAL FOOTAGE

REFERENCE FOR FOOTAGE MEASURE GROUND LEVEL +6.92'

LENGTHS ARE NUMBERED FROM SURFACE

COMMENTS

SERVICED BY

WA-1363 (10/87)

AC_CPUC_0114925

SoCalGas-7.0166

VERTILOG®

Western Atlas International
A Litton/Dresser Company

PAGE 1 OF 1

CUSTOMER	SOUTHERN CALIFORNIA GAS COMPANY	WORK ORDER NO.	124303	DATE	12-16-88
LEASE/WELL NO.	STANDARD SESNON No. 9	CUSTOMER ORDER NO.			
FIELD	ALISO CANYON	COUNTY	LOS ANGELES	STATE	CALIFORNIA
CASING O.D.	7" WEIGHT(S) 23,26,29	NOMINAL WALL THICKNESS		GRADE	J-55,N-80
TOTAL FOOTAGE INSPECTED	8553'	FROM	SURFACE	TO	8553' DEPTH

SUBSURFACE CASING DEFECT REPORT

LENGTH NO.	TYPE DEFECT	PENETRATION	LENGTH NO.	TYPE DEFECT	PENETRATION
OUTSIDE 13-3/8" SURFACE CASING					
51	OD IP	21 - 40			
62	OD IP	21 - 40			
64	OD IP	21 - 40			
67	ID IP	21 - 40			
85	ID IP	21 - 40			
91	ID IP	21 - 40			

ABBREVIATIONS:

O.D. – OUTSIDE DIAMETER
I.D. – INSIDE DIAMETER
I.S. – INSIDE SURFACE PIPE
T.L. – THROUGHOUT LENGTH
I.P. – ISOLATED PITTING
C.C. – CIRCUMFERENTIAL CORROSION
G.C. - GENERAL CORROSION

WA-1364-C (10/87)

Ex. II - 15

Due to the large file size, please view document DOGGR_03700762_Vertilog_12-16-1988 at the below publicly available website. The native file of this document is available upon request.

(https://secure.conservation.ca.gov/WellRecord/037/03700762/tifs/03700762_Vertilog_12-16-1988.tif) (accessed March 20, 2020)

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

BAKER HUGHES a GE company

Company	Southern California Gas Company
Well	Standard Sesnon 9
Field	Aliso Canyon
County	Los Angeles
State	California
Location:	

Section 28	Township 3N	Range 16W	

Date	Sep. 6, 2018
Service Order	US142360J
Recorded by	Josh Farris
Witnessed by	Tom McMahon
API Serial No.	040370076200

Permanent Datum:	DF	Elevation: 2842.630 ft.		Depth	8580.000
Log Measured From:	DF	6.920 ft. above Perm. Datum		Btm. Log Interval	8580.000
Drilling Measured From:	DF	6.920 ft. above Perm. Datum		Top Log Interval	0.000
				Fluid Type	KCL

Casing Data

Size	Weight	Grade	From	To	Length
7 inch	23.0 lb/ft	J55	0'	3777'	3777.0
7 inch	23.0 lb/ft	N-80	3777'	5463'	1686.0
7 inch	26.0 lb/ft	N-80	5463'	7093'	1630.0
7 inch	29.0 lb/ft	N-80	7093'	8625'	1532.0
5 inch	17.93 lb/ft	N-80	8599'	8859'	260.0

Software Version 7.6.1.4

Equipment Data

Run	Trip	Tool Type	Tool Series	Serial Number	Position
1	1	HRVRT MFL	4997	PB13150203	LOWER
1	1	HRVRT MFL	4997	PB12116589	UPPER
1	1	HRVRT TELEM	4993	265	

Calibration Data

Calibration File Name	4997-7-001-PB12116589-U.CAL

Date of Calibration	08/04/2016 15:08
Calibration Identifier	64583794-BD8B-4D61-AD05-9F80BA6D56F5
Tool Number	4997-00
Calibrator Number	4997-7-001
Calibrator Size	(7 In - 178 mm)
Calibration Source File	20160804_144043_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.4.0
Comment	RMA1273

Calibration Data

Calibration File Name	4997-7-001-PB13150203-U.CAL
Date of Calibration	08/01/2014 09:59
Calibration Identifier	7D517C26-6B34-4D7B-9646-D03C51CFEE9F
Tool Number	4997-00
Calibrator Number	4997-7-001
Calibrator Size	(7 In - 178 mm)
Calibration Source File	20140801_092608_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.4.0
Comment	New PO 4506516300

Remarks

Interpretation

The HRVRT data was correlated to the SLB GRN log dated 9-7-2018.

The following external hardware was detected and excluded from analysis:

```
  13.98 ft   Hardware - External CSG Head Response
 593.91 ft   Hardware - Bottom of 13.375" External Casing
8571.84 ft   Float Collar
```

Seamless pipe noise was detected in several joints. See Joint #22 as example.

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	12.24	38.53	26.29	Class 1	-	-	-

2	38.53	74.18	35.65	Class 1	-	-	-
3	74.18	115.79	41.61	Class 1	-	-	-
4	115.79	157.65	41.86	Class 1	-	-	-
5	157.65	199.80	42.15	Class 1	-	-	-
6	199.80	241.77	41.97	Class 1	-	-	-
7	241.77	284.16	42.39	Class 1	-	-	-
8	284.16	326.19	42.03	Class 1	-	-	-
9	326.19	368.28	42.09	Class 1	-	-	-
10	368.28	410.35	42.07	Class 1	-	-	-
11	410.35	453.02	42.67	Class 1	-	-	-
12	453.02	494.83	41.81	Class 1	-	-	-
13	494.83	535.98	41.15	Class 1	-	-	-
14	535.98	578.15	42.17	Class 1	-	-	-
15	578.15	619.29	41.14	Class 1	-	-	-
16	619.29	660.47	41.18	Class 1	-	-	-
17	660.47	702.80	42.33	Class 1	-	-	-
18	702.80	744.70	41.90	Class 1	-	-	-
19	744.70	784.93	40.23	Class 1	16.0%	773.01	OD
20	784.93	826.75	41.82	Class 1	-	-	-
21	826.75	869.01	42.26	Class 1	-	-	-
22	869.01	911.47	42.46	Class 1	-	-	-
23	911.47	953.31	41.84	Class 1	-	-	-
24	953.31	995.20	41.89	Class 1	-	-	-
25	995.20	1037.22	42.02	Class 1	-	-	-
26	1037.22	1078.98	41.76	Class 1	-	-	-
27	1078.98	1121.36	42.38	Class 1	-	-	-
28	1121.36	1158.13	36.77	Class 1	-	-	-
29	1158.13	1200.42	42.29	Class 1	-	-	-
30	1200.42	1243.55	43.13	Class 1	-	-	-
31	1243.55	1285.51	41.96	Class 1	-	-	-
32	1285.51	1325.94	40.43	Class 1	-	-	-
33	1325.94	1368.28	42.34	Class 1	-	-	-
34	1368.28	1410.38	42.10	Class 1	-	-	-
35	1410.38	1451.62	41.24	Class 1	-	-	-
36	1451.62	1493.16	41.54	Class 1	-	-	-
37	1493.16	1535.70	42.54	Class 1	-	-	-
38	1535.70	1578.16	42.46	Class 1	-	-	-
39	1578.16	1619.86	41.70	Class 1	-	-	-
40	1619.86	1662.39	42.53	Class 1	-	-	-
41	1662.39	1704.09	41.70	Class 1	-	-	-
42	1704.09	1741.16	37.07	Class 1	-	-	-
43	1741.16	1781.97	40.81	Class 1	-	-	-
44	1781.97	1822.61	40.64	Class 1	-	-	-
45	1822.61	1865.02	42.41	Class 1	-	-	-
46	1865.02	1905.07	40.05	Class 1	-	-	-
47	1905.07	1945.86	40.79	Class 1	-	-	-
48	1945.86	1987.40	41.54	Class 1	-	-	-
49	1987.40	2028.80	41.40	Class 1	-	-	-
50	2028.80	2070.51	41.71	Class 1	-	-	-
51	2070.51	2113.28	42.77	Class 1	-	-	-
52	2113.28	2154.65	41.37	Class 1	-	-	-
53	2154.65	2197.03	42.38	Class 1	-	-	-
54	2197.03	2239.08	42.05	Class 1	-	-	-
55	2239.08	2275.74	36.66	Class 1	-	-	-
56	2275.74	2317.66	41.92	Class 1	-	-	-
57	2317.66	2357.88	40.22	Class 1	-	-	-
58	2357.88	2399.62	41.74	Class 1	-	-	-
59	2399.62	2442.99	43.37	Class 1	-	-	-
60	2442.99	2485.08	42.09	Class 1	-	-	-
61	2485.08	2525.60	40.52	Class 1	-	-	-
62	2525.60	2567.40	41.80	Class 1	-	-	-
63	2567.40	2606.93	39.53	Class 1	-	-	-
64	2606.93	2648.93	42.00	Class 1			

64	2606.93	2648.93	42.00	Class 1	-	-	-
65	2648.93	2690.98	42.05	Class 1	-	-	-
66	2690.98	2733.14	42.16	Class 1	-	-	-
67	2733.14	2773.16	40.02	Class 1	-	-	-
68	2773.16	2814.96	41.80	Class 1	-	-	-
69	2814.96	2856.26	41.30	Class 1	-	-	-
70	2856.26	2899.36	43.10	Class 1	-	-	-
71	2899.36	2936.78	37.42	Class 1	-	-	-
72	2936.78	2978.76	41.98	Class 1	-	-	-
73	2978.76	3020.71	41.95	Class 1	-	-	-
74	3020.71	3063.24	42.53	Class 1	-	-	-
75	3063.24	3105.60	42.36	Class 1	-	-	-
76	3105.60	3147.28	41.68	Class 1	-	-	-
77	3147.28	3188.93	41.65	Class 1	-	-	-
78	3188.93	3227.81	38.88	Class 1	-	-	-
79	3227.81	3269.52	41.71	Class 1	-	-	-
80	3269.52	3311.18	41.66	Class 1	-	-	-
81	3311.18	3353.08	41.90	Class 1	-	-	-
82	3353.08	3394.55	41.47	Class 1	-	-	-
83	3394.55	3436.81	42.26	Class 1	-	-	-
84	3436.81	3479.00	42.19	Class 1	-	-	-
85	3479.00	3520.14	41.14	Class 1	-	-	-
86	3520.14	3562.81	42.67	Class 1	-	-	-
87	3562.81	3598.36	35.55	Class 1	-	-	-
88	3598.36	3640.95	42.59	Class 1	-	-	-
89	3640.95	3683.71	42.76	Class 1	-	-	-
90	3683.71	3726.33	42.62	Class 1	-	-	-
91	3726.33	3768.12	41.79	Class 1	-	-	-
92	3768.12	3810.20	42.08	Class 1	-	-	-
93	3810.20	3852.86	42.66	Class 1	-	-	-
94	3852.86	3895.41	42.55	Class 1	15.0%	3874.13	OD
95	3895.41	3937.52	42.11	Class 1	-	-	-
96	3937.52	3980.90	43.38	Class 1	-	-	-
97	3980.90	4023.22	42.32	Class 1	-	-	-
98	4023.22	4065.65	42.43	Class 1	-	-	-
99	4065.65	4106.87	41.22	Class 1	-	-	-
100	4106.87	4148.24	41.37	Class 1	-	-	-
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102	4190.33	4232.66	42.33	Class 1	-	-	-
103	4232.66	4275.03	42.37	Class 1	-	-	-
104	4275.03	4315.13	40.10	Class 1	-	-	-
105	4315.13	4357.87	42.74	Class 1	-	-	-
106	4357.87	4398.67	40.80	Class 1	-	-	-
107	4398.67	4442.62	43.95	Class 1	-	-	-
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109	4485.49	4527.42	41.93	Class 1	-	-	-
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114	4695.45	4738.08	42.63	Class 1	-	-	-
115	4738.08	4780.42	42.34	Class 1	-	-	-
116	4780.42	4822.80	42.38	Class 1	-	-	-
117	4822.80	4865.13	42.33	Class 1	-	-	-
118	4865.13	4906.93	41.80	Class 1	-	-	-
119	4906.93	4948.57	41.64	Class 1	18.0%	4932.25	ID
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121	4991.13	5033.11	41.98	Class 1	-	-	-
122	5033.11	5075.90	42.79	Class 1	-	-	-
123	5075.90	5118.18	42.28	Class 1	-	-	-
124	5118.18	5161.13	42.95	Class 1	-	-	-
125	5161.13	5203.23	42.10	Class 1	-	-	-
126	5203.23	5245.17	41.94	Class 1	-	-	-

127	5245.17	5287.55	42.38	Class 1	-	-	-
128	5287.55	5326.64	39.09	Class 1	-	-	-
129	5326.64	5369.45	42.81	Class 1	-	-	-
130	5369.45	5411.86	42.41	Class 1	-	-	-
131	5411.86	5454.90	43.04	Class 1	-	-	-
132	5454.90	5496.15	41.25	Class 1	-	-	-
133	5496.15	5538.08	41.93	Class 1	-	-	-
134	5538.08	5581.39	43.31	Class 1	-	-	-
135	5581.39	5624.07	42.68	Class 1	-	-	-
136	5624.07	5667.96	43.89	Class 1	-	-	-
137	5667.96	5710.53	42.57	Class 1	-	-	-
138	5710.53	5753.63	43.10	Class 1	-	-	-
139	5753.63	5795.90	42.27	Class 1	-	-	-
140	5795.90	5838.95	43.05	Class 1	-	-	-
141	5838.95	5880.33	41.38	Class 1	-	-	-
142	5880.33	5923.96	43.63	Class 1	-	-	-
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144	5967.00	6010.17	43.17	Class 1	-	-	-
145	6010.17	6053.92	43.75	Class 1	-	-	-
146	6053.92	6095.40	41.48	Class 1	-	-	-
147	6095.40	6138.92	43.52	Class 1	-	-	-
148	6138.92	6181.79	42.87	Class 1	-	-	-
149	6181.79	6223.50	41.71	Class 1	-	-	-
150	6223.50	6266.53	43.03	Class 1	-	-	-
151	6266.53	6309.87	43.34	Class 1	-	-	-
152	6309.87	6352.97	43.10	Class 1	-	-	-
153	6352.97	6396.53	43.56	Class 1	-	-	-
154	6396.53	6439.50	42.97	Class 1	-	-	-
155	6439.50	6482.51	43.01	Class 1	-	-	-
156	6482.51	6525.42	42.91	Class 1	-	-	-
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159	6611.15	6654.77	43.62	Class 1	-	-	-
160	6654.77	6698.79	44.02	Class 1	-	-	-
161	6698.79	6742.52	43.73	Class 1	-	-	-
162	6742.52	6784.53	42.01	Class 1	-	-	-
163	6784.53	6826.07	41.54	Class 1	-	-	-
164	6826.07	6869.30	43.23	Class 1	-	-	-
165	6869.30	6912.74	43.44	Class 1	-	-	-
166	6912.74	6956.22	43.48	Class 1	-	-	-
167	6956.22	6999.59	43.37	Class 1	-	-	-
168	6999.59	7043.24	43.65	Class 1	-	-	-
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170	7086.75	7129.73	42.98	Class 1	-	-	-
171	7129.73	7172.46	42.73	Class 1	-	-	-
172	7172.46	7214.81	42.35	Class 1	-	-	-
173	7214.81	7257.58	42.77	Class 1	-	-	-
174	7257.58	7299.71	42.13	Class 1	-	-	-
175	7299.71	7341.70	41.99	Class 1	16.0%	7315.51	ID
176	7341.70	7385.13	43.43	Class 1	-	-	-
177	7385.13	7427.08	41.95	Class 1	-	-	-
178	7427.08	7470.85	43.77	Class 1	-	-	-
179	7470.85	7513.45	42.60	Class 1	-	-	-
180	7513.45	7556.89	43.44	Class 1	-	-	-
181	7556.89	7599.71	42.82	Class 1	-	-	-
182	7599.71	7642.37	42.66	Class 1	-	-	-
183	7642.37	7685.12	42.75	Class 1	-	-	-
184	7685.12	7727.80	42.68	Class 1	-	-	-
185	7727.80	7770.52	42.72	Class 1	-	-	-
186	7770.52	7813.28	42.76	Class 1	-	-	-
187	7813.28	7855.44	42.16	Class 1	-	-	-
188	7855.44	7897.42	41.98	Class 1	-	-	-

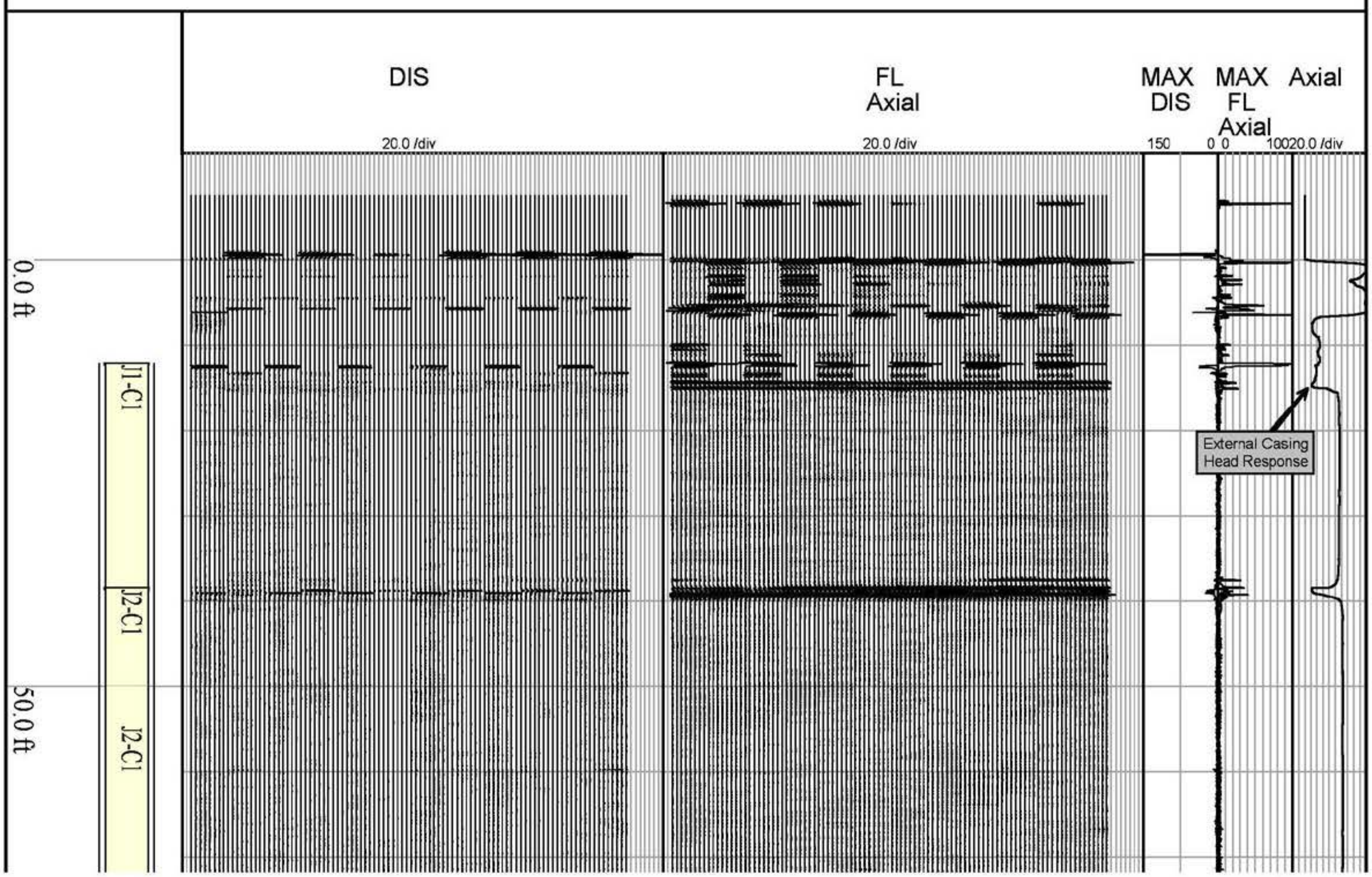
189	7897.42	7940.80	43.38	Class 1	-	-	-
190	7940.80	7982.98	42.18	Class 1	-	-	-
191	7982.98	8020.03	37.05	Class 1	-	-	-
192	8020.03	8062.36	42.33	Class 1	-	-	-
193	8062.36	8104.78	42.42	Class 1	-	-	-
194	8104.78	8147.35	42.57	Class 1	-	-	-
195	8147.35	8190.89	43.54	Class 1	-	-	-
196	8190.89	8233.86	42.97	Class 1	-	-	-
197	8233.86	8277.47	43.61	Class 1	-	-	-
198	8277.47	8319.86	42.39	Class 1	-	-	-
199	8319.86	8362.54	42.68	Class 1	-	-	-
200	8362.54	8404.99	42.45	Class 1	-	-	-
201	8404.99	8447.21	42.22	Class 1	-	-	-
202	8447.21	8486.46	39.25	Class 1	-	-	-
203	8486.46	8528.95	42.49	Class 2	23.0%	8522.45	ID
204	8528.95	8571.84	42.89	Class 4	81.0%	8543.19	ID
205	8571.84	8581.63	9.79	Class 1	-	-	-

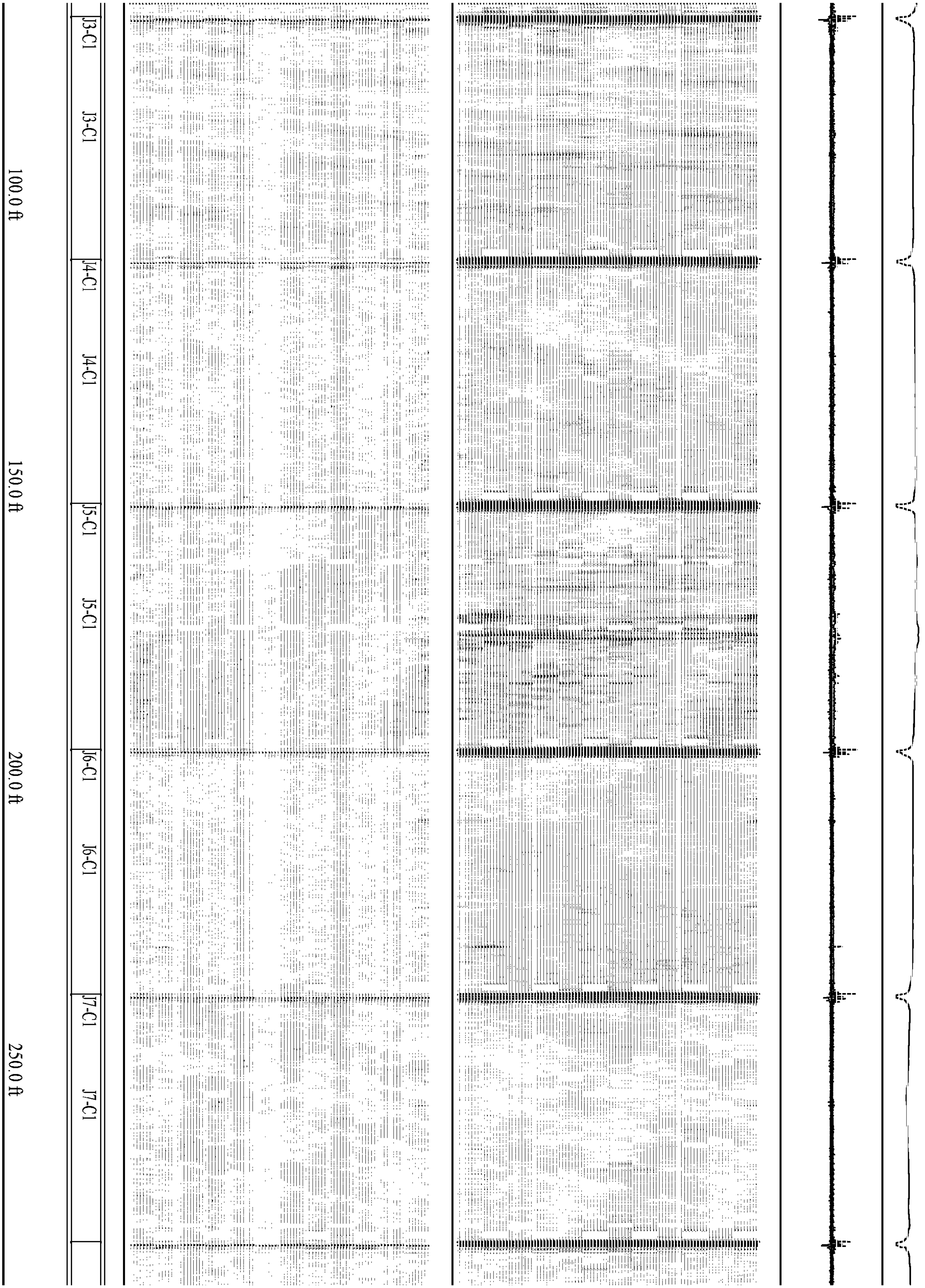
Southern California Gas Company Standard Sesnon 9

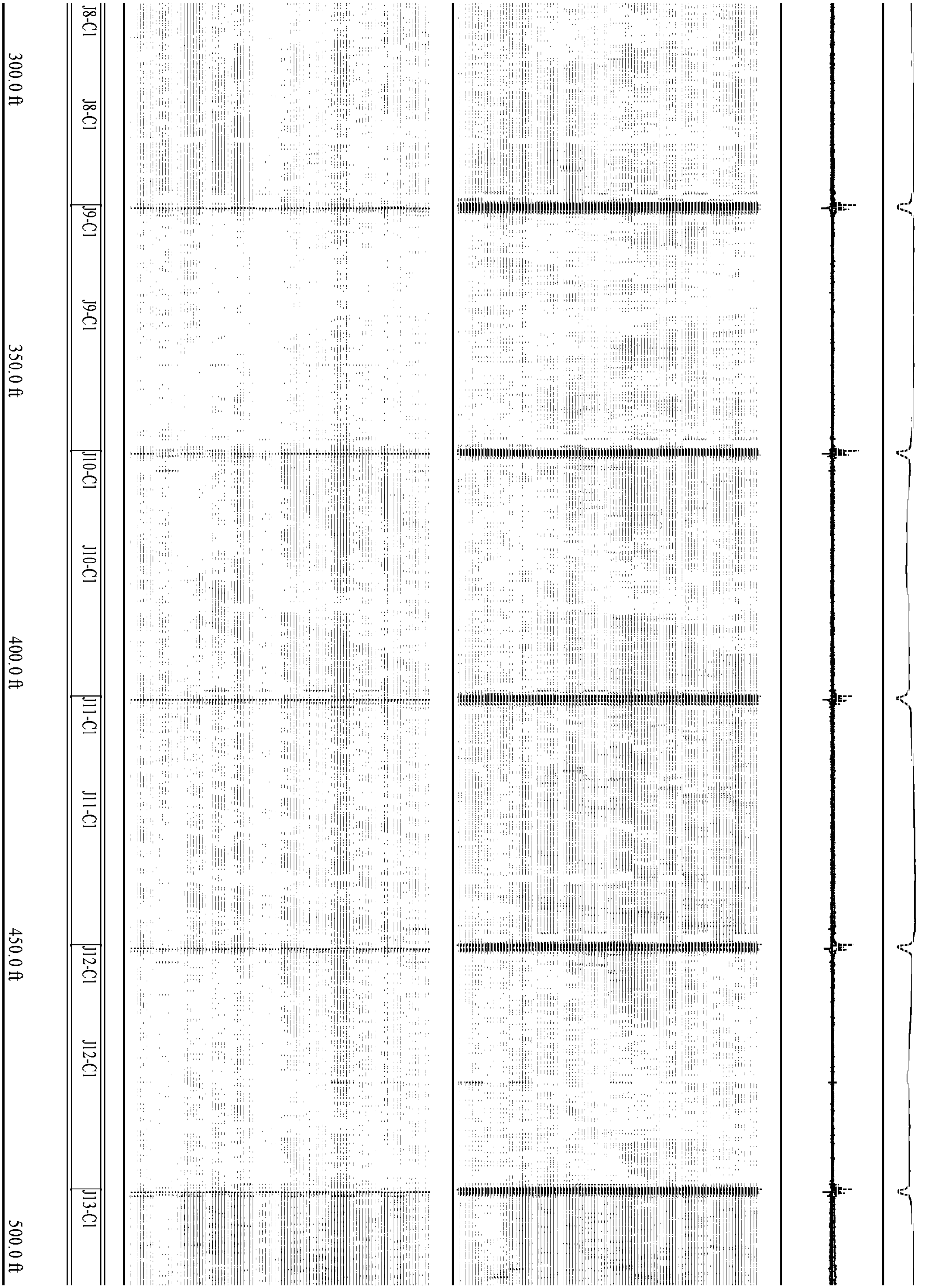
File 20180906_15093B_RSP_0_0_0_0_0.mvl

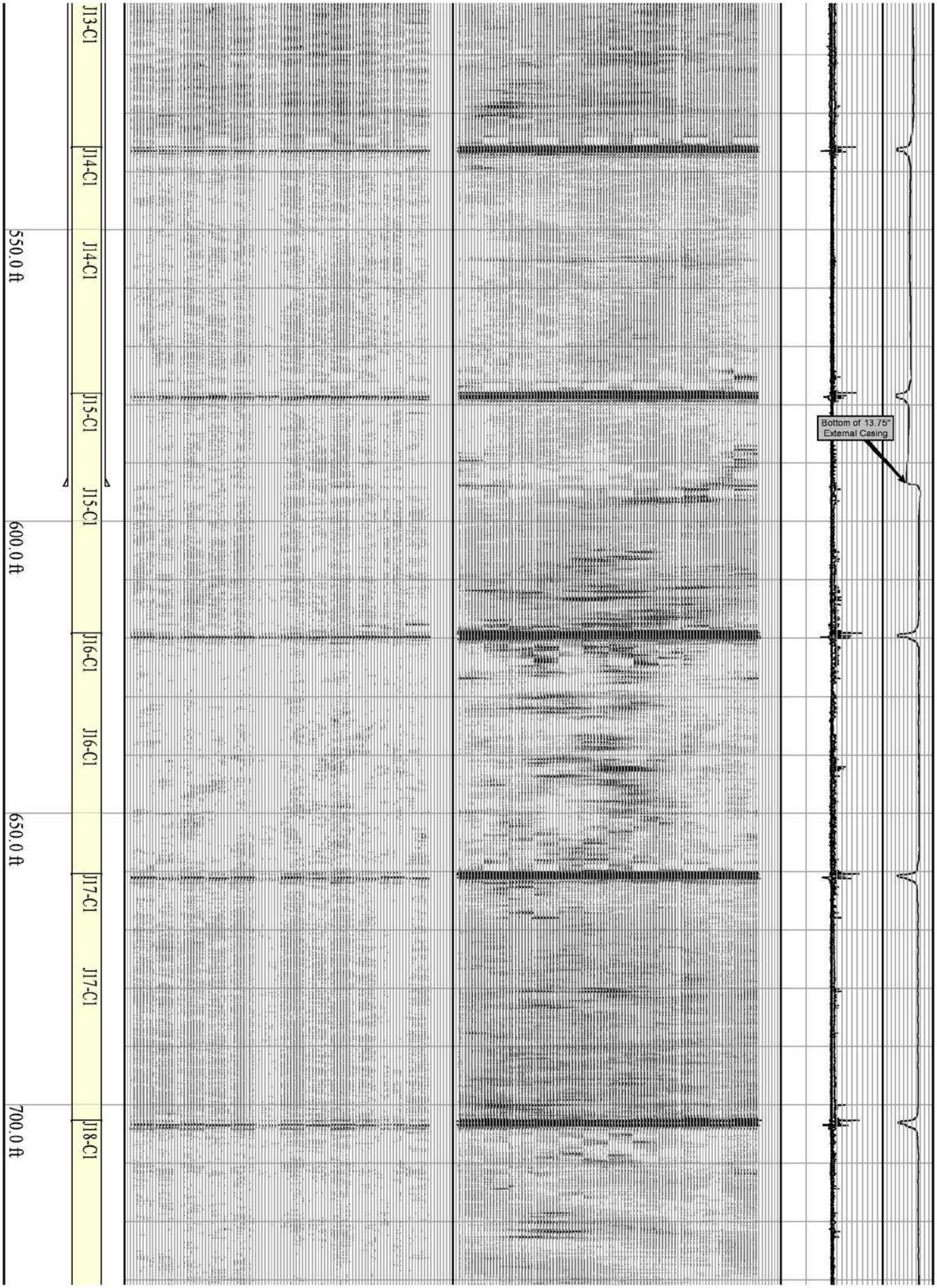
MAIN LOG (5"/100')

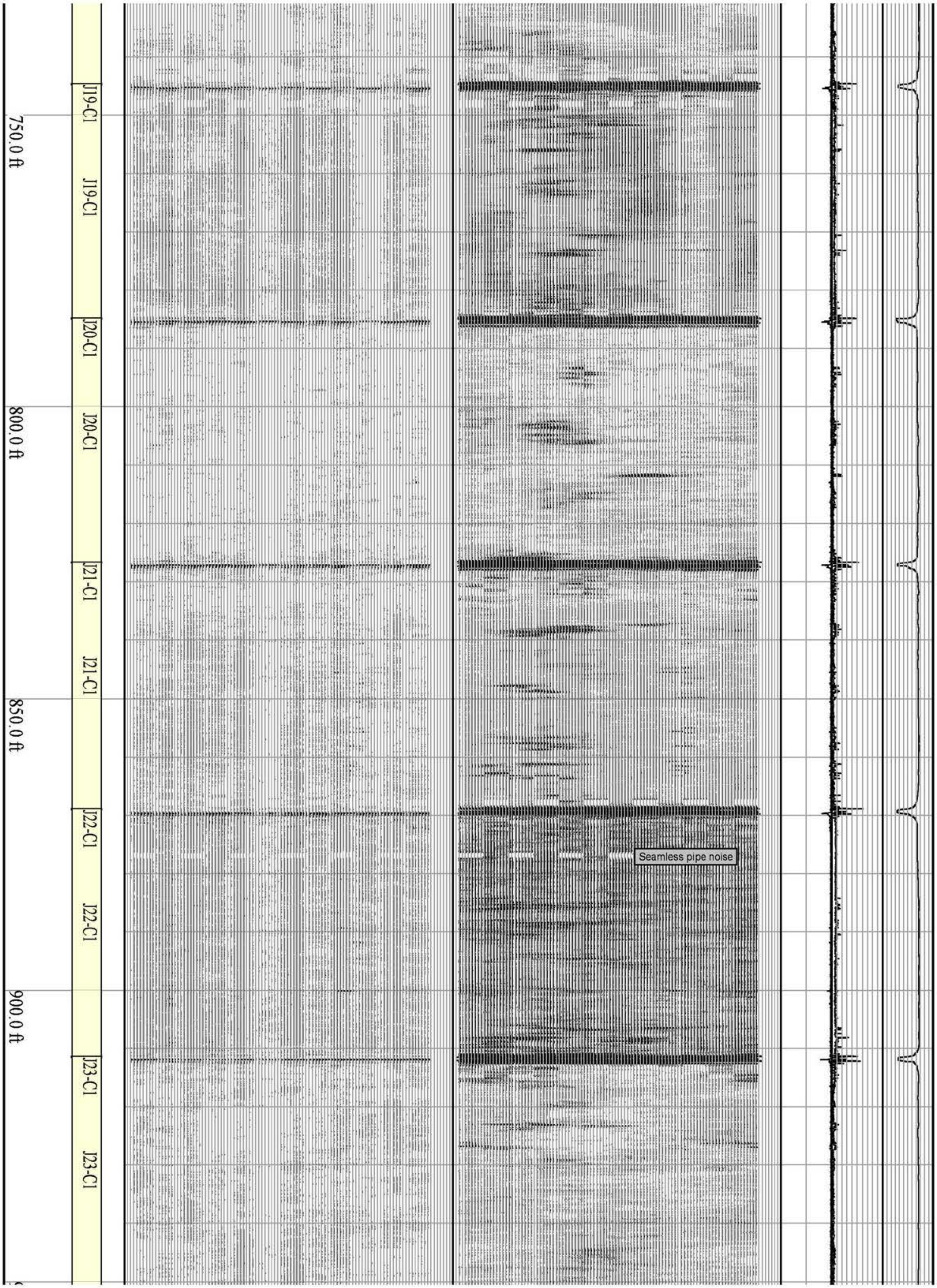
Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%

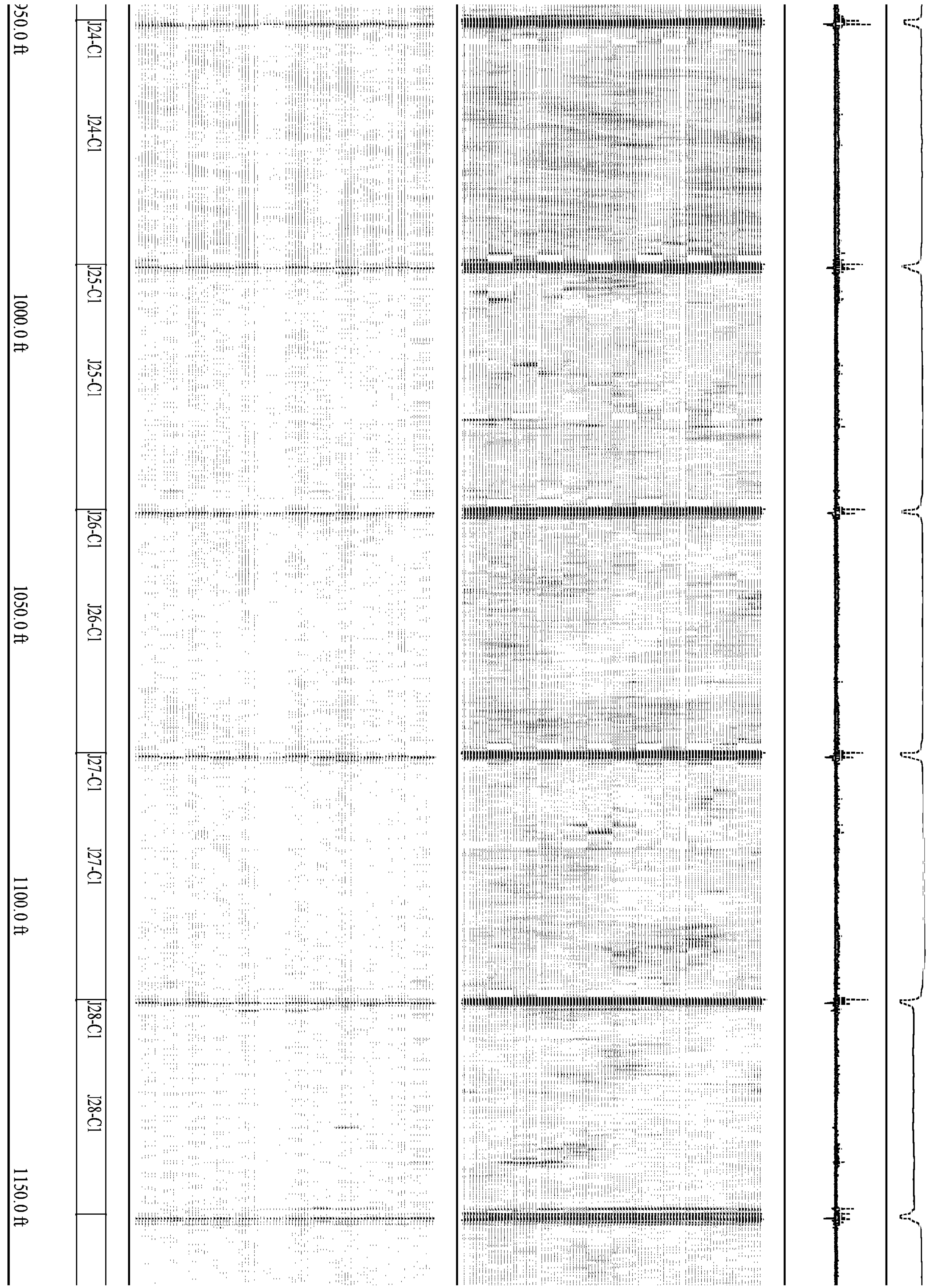


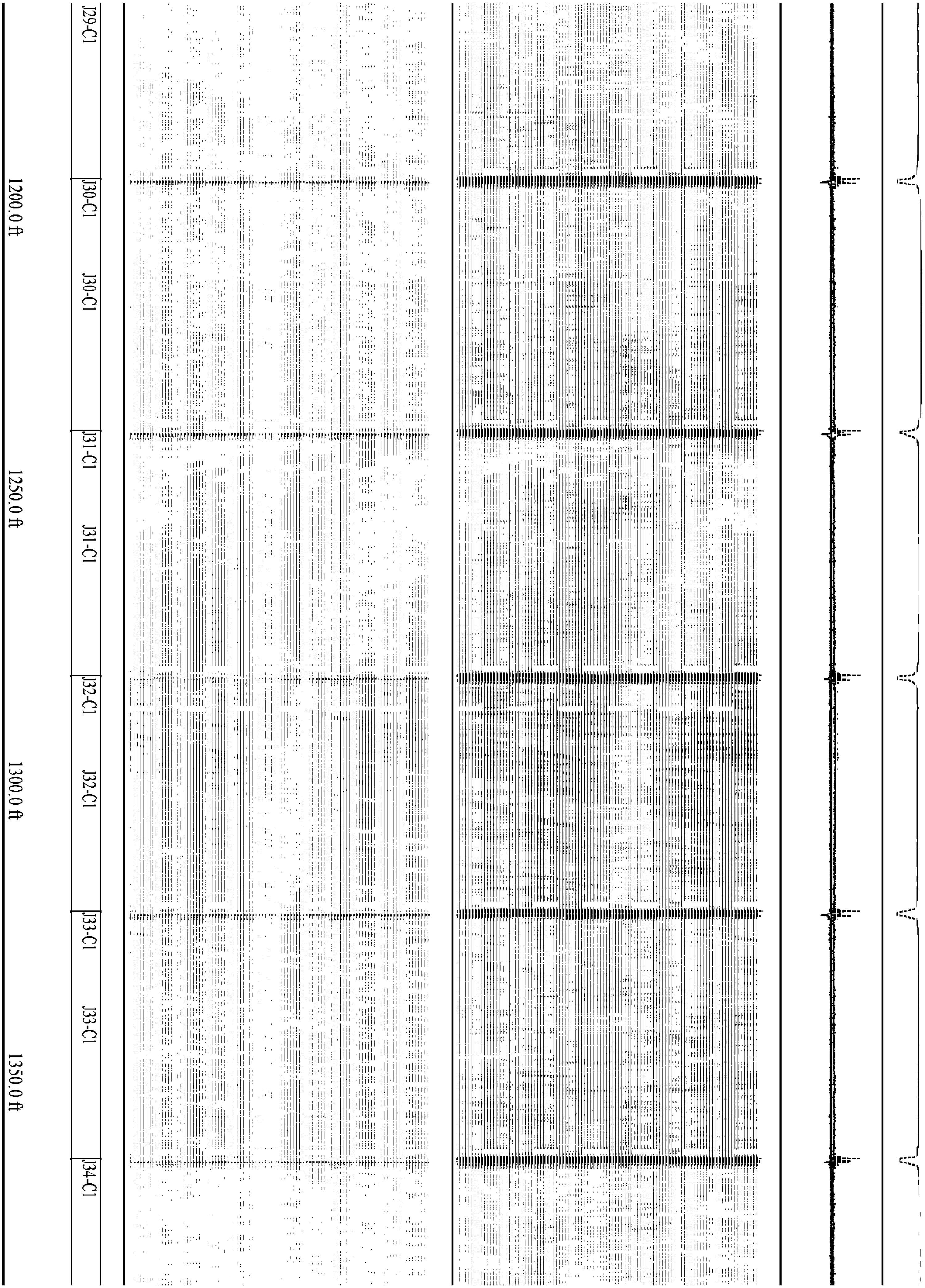

J3-C1
J3-C1
100.0 ft
J4-C1
J4-C1
150.0 ft
J5-C1
J5-C1
200.0 ft
J6-C1
J6-C1
J7-C1
250.0 ft
J7-C1

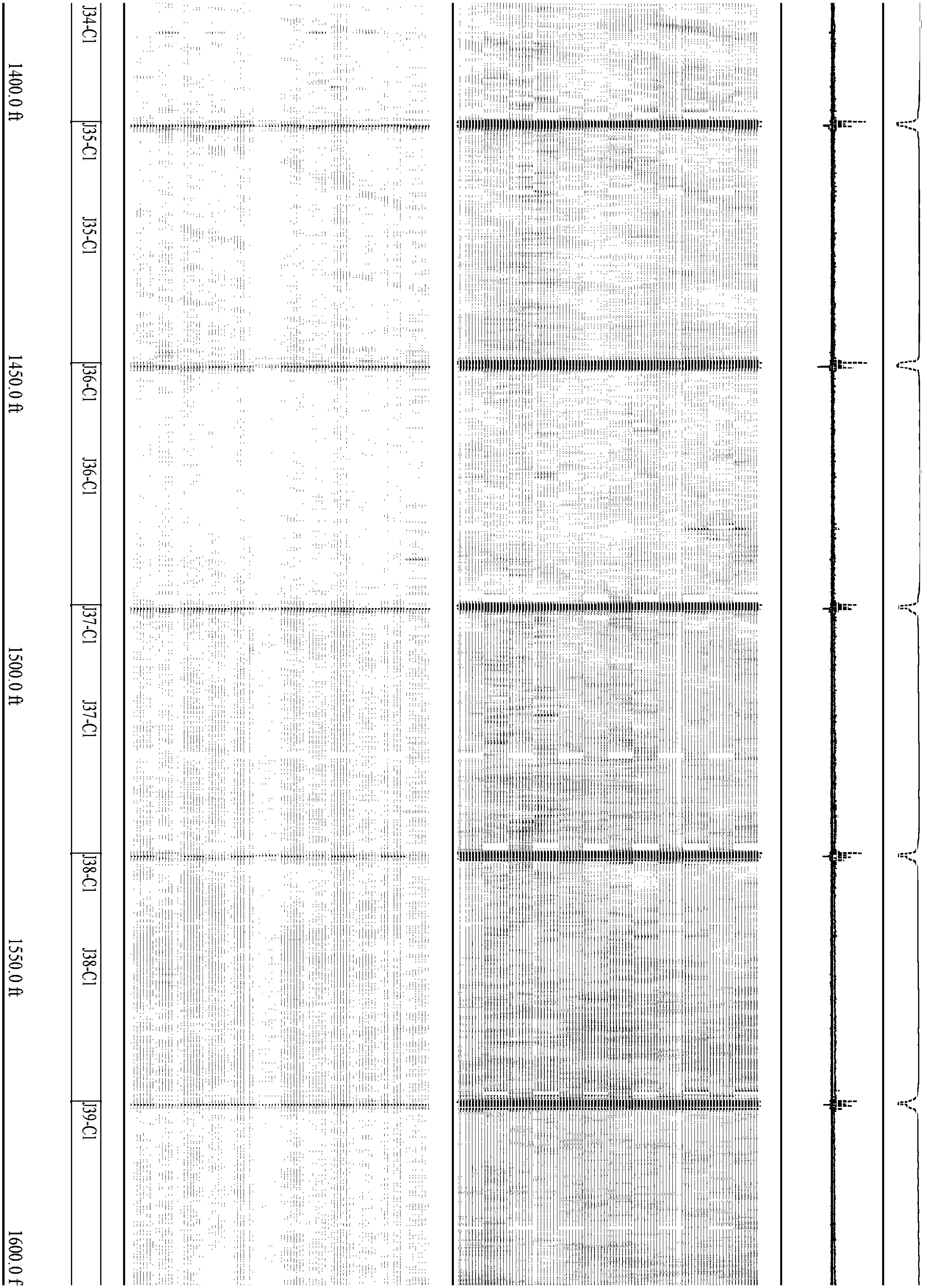

300.0 ft
350.0 ft
400.0 ft
450.0 ft
500.0 ft
J8-C1
J8-C1
J9-C1
J9-C1
J10-C1
J10-C1
J11-C1
J11-C1
J12-C1
J12-C1
J13-C1

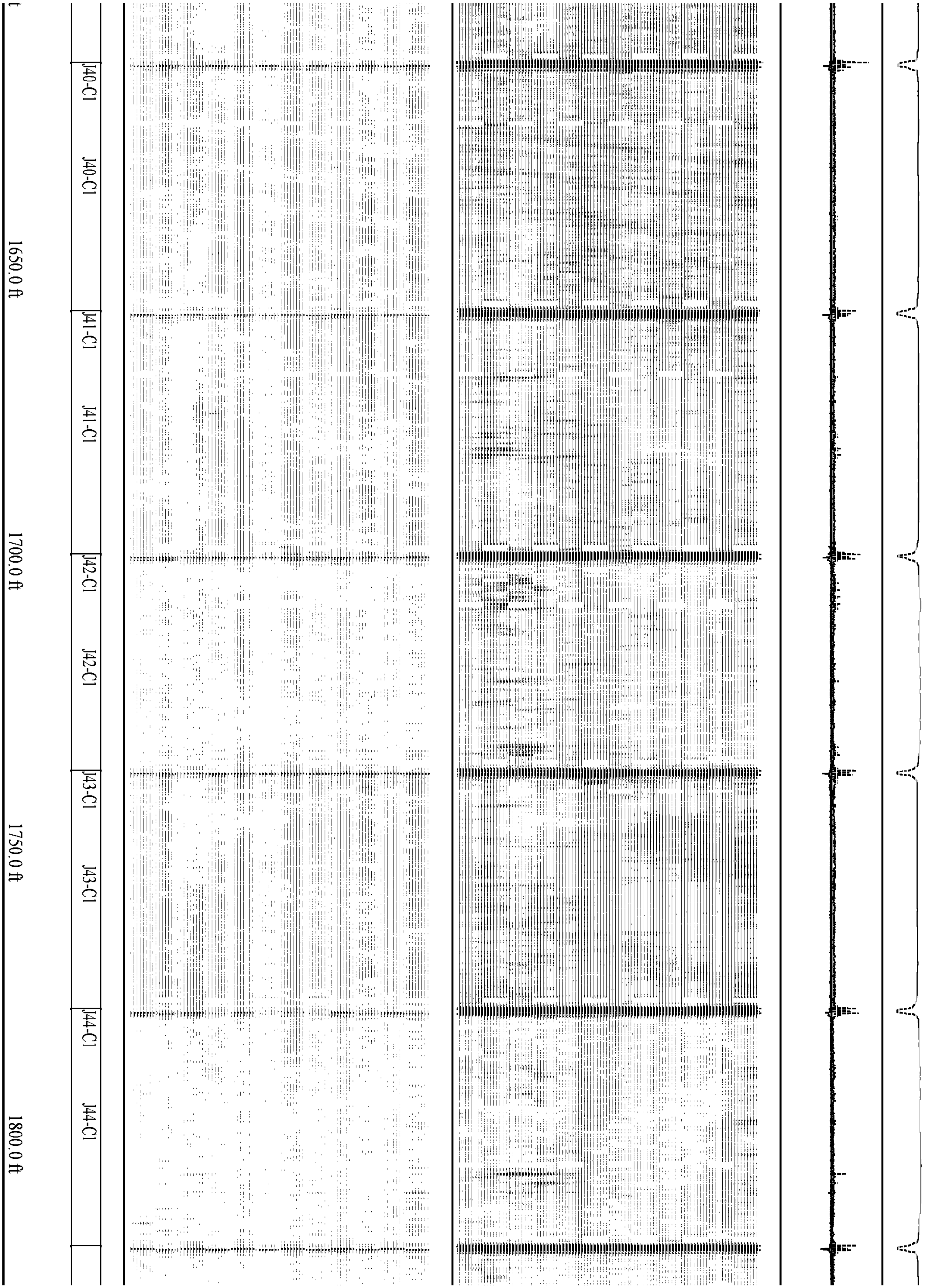

J13-C1
J14-C1
J14-C1
J15-C1
J15-C1
J16-C1
J16-C1
J17-C1
J17-C1
J18-C1
550.0 ft
600.0 ft
650.0 ft
700.0 ft
Bottom of 13.75"
External Casing

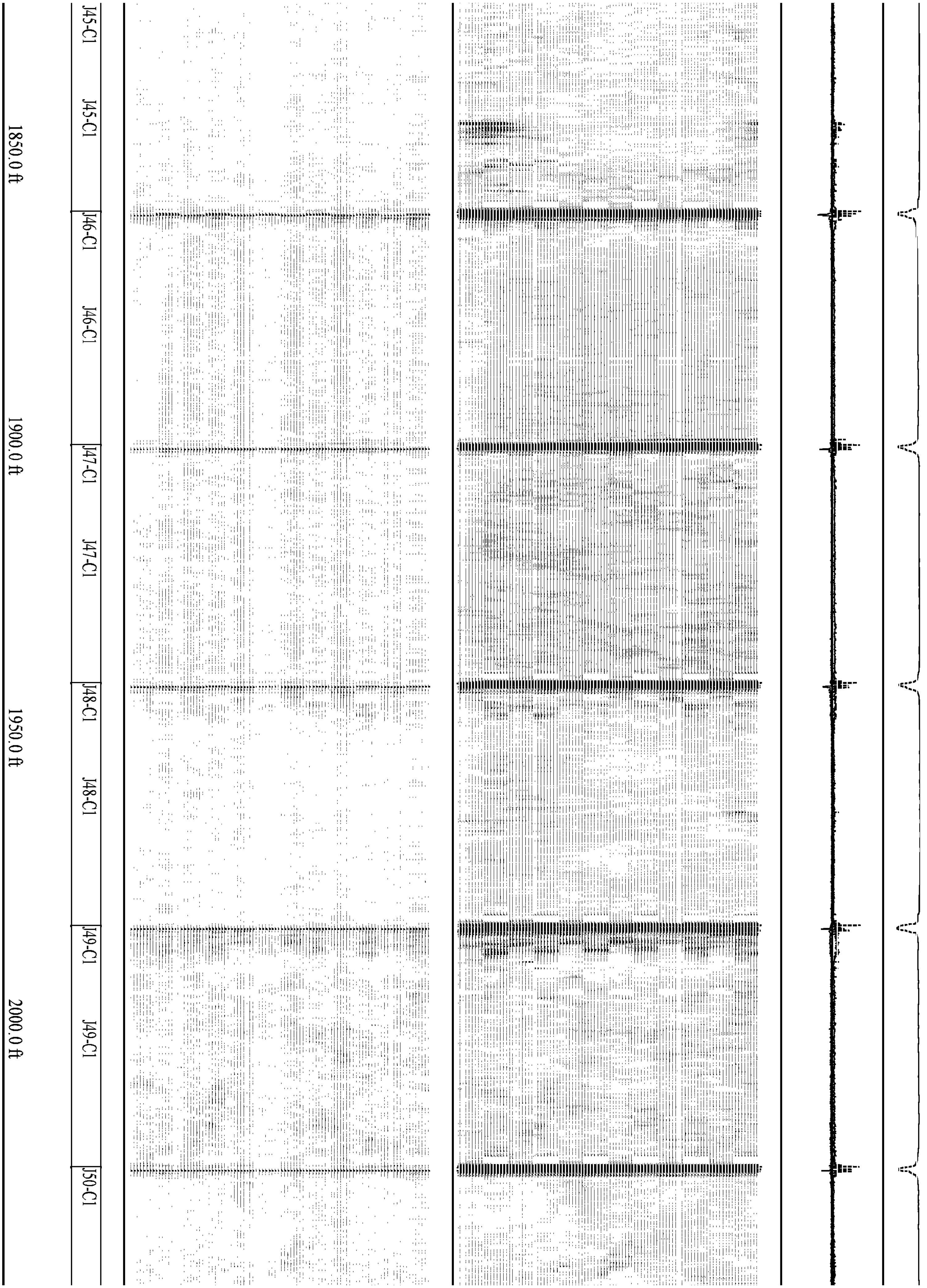

750.0 ft
800.0 ft
850.0 ft
900.0 ft
J19-C1
J19-C1
J20-C1
J20-C1
J21-C1
J21-C1
J22-C1
J22-C1
J23-C1
J23-C1
Seamless pipe noise

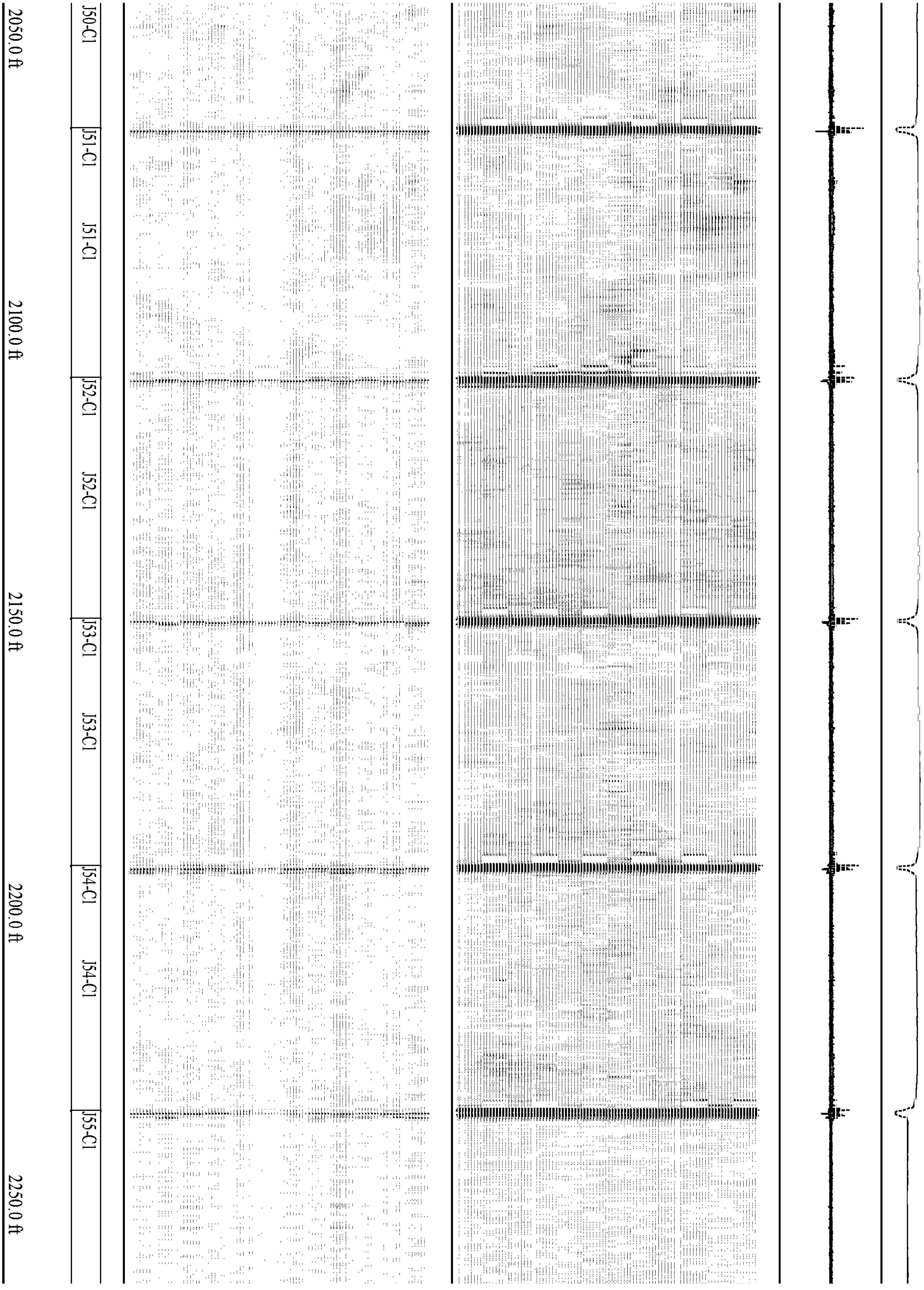

1000.0 ft
1050.0 ft
1100.0 ft
1150.0 ft
J24-C1
J24-C1
J25-C1
J25-C1
J26-C1
J26-C1
J27-C1
J27-C1
J28-C1
J28-C1

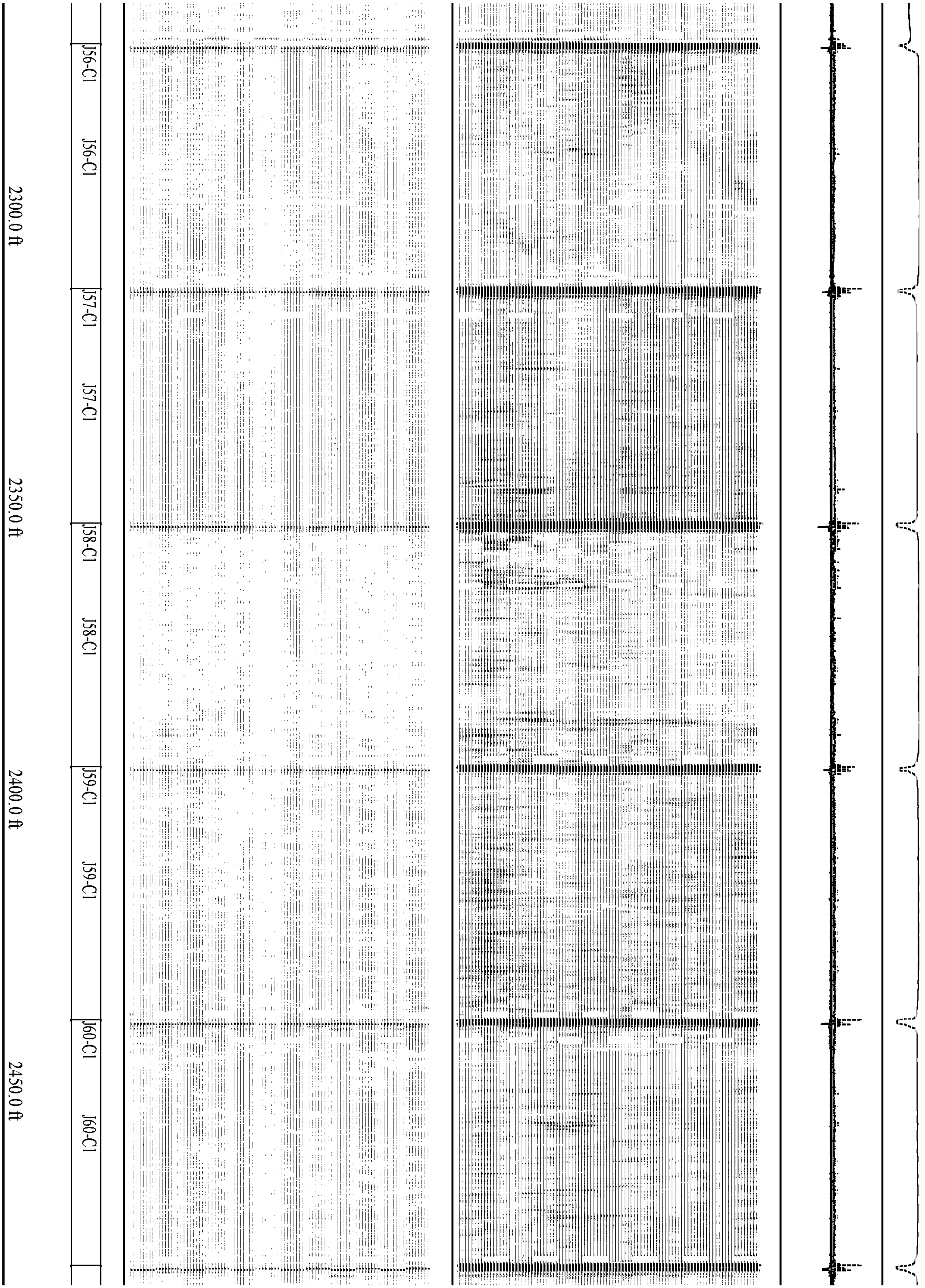

J29-C1
1200.0 ft
J30-C1
J30-C1
J31-C1
1250.0 ft
J31-C1
J32-C1
1300.0 ft
J32-C1
J33-C1
J33-C1
1350.0 ft
J34-C1


1400.0 ft
1450.0 ft
1500.0 ft
1550.0 ft
1600.0 f
J34-C1
J35-C1
J35-C1
J36-C1
J36-C1
J37-C1
J37-C1
J38-C1
J38-C1
J39-C1

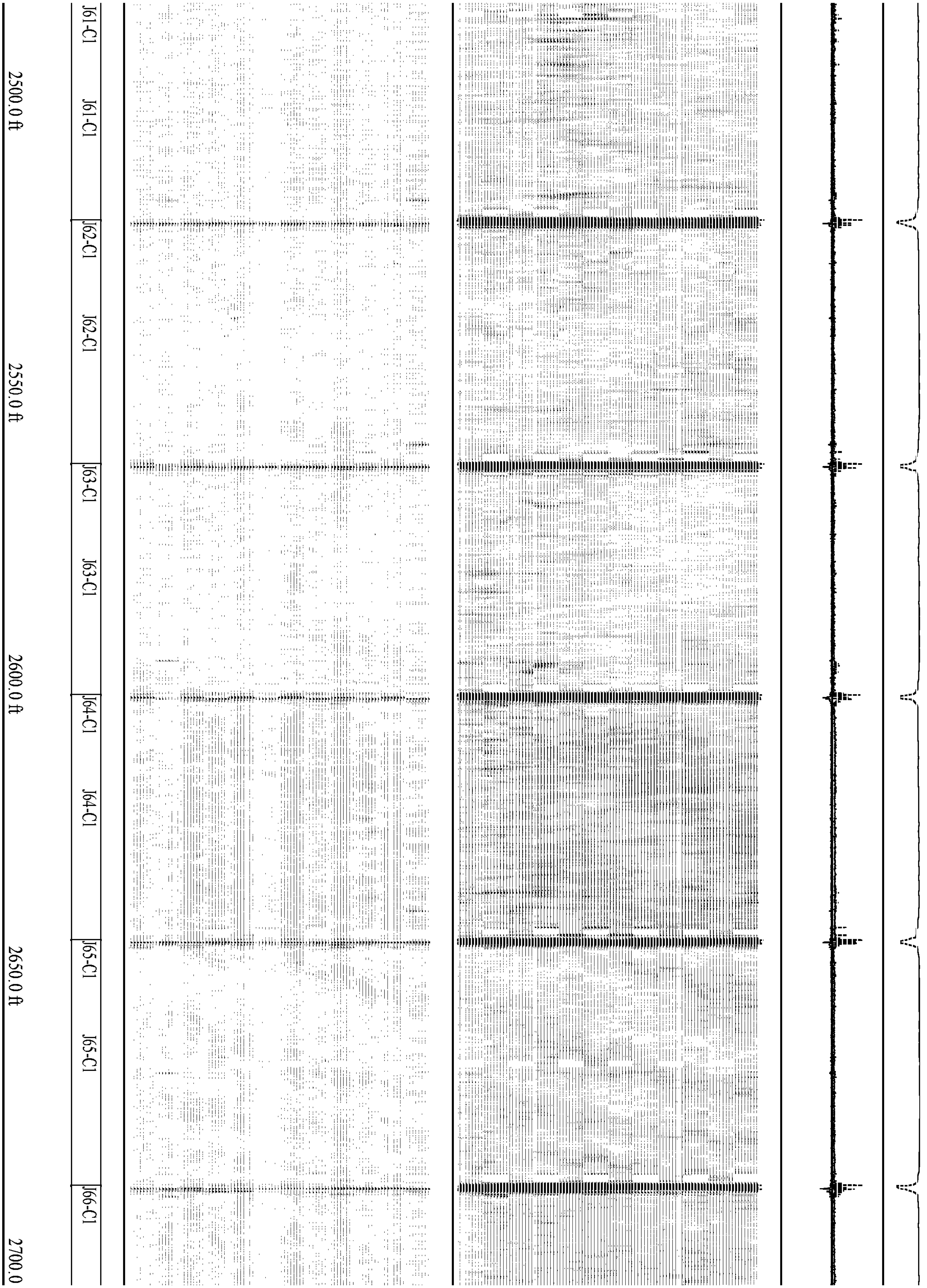

J40-C1
J40-C1
1650.0 ft
J41-C1
J41-C1
1700.0 ft
J42-C1
J42-C1
J43-C1
1750.0 ft
J43-C1
J44-C1
1800.0 ft
J44-C1

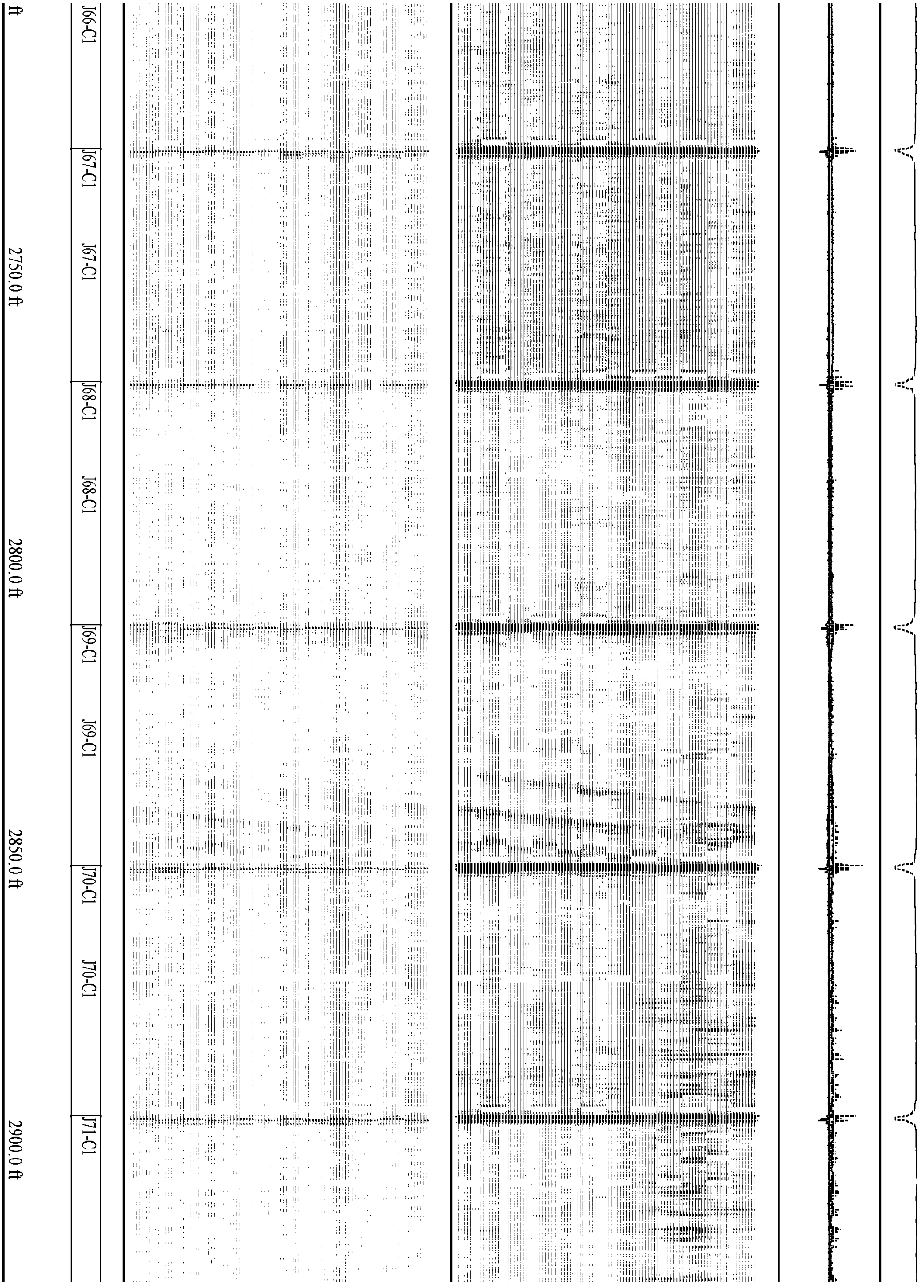

1850.0 ft
1900.0 ft
1950.0 ft
2000.0 ft
J45-C1
J45-C1
J46-C1
J46-C1
J47-C1
J47-C1
J48-C1
J48-C1
J49-C1
J49-C1
J50-C1


2050.0 ft
J50-C1
J51-C1
J51-C1
2100.0 ft
J52-C1
J52-C1
2150.0 ft
J53-C1
J53-C1
J54-C1
2200.0 ft
J54-C1
J55-C1
2250.0 ft



2300.0 ft
2350.0 ft
2400.0 ft
2450.0 ft
J56-C1
J56-C1
J57-C1
J57-C1
J58-C1
J58-C1
J59-C1
J59-C1
J60-C1
J60-C1


2500.0 ft
2550.0 ft
2600.0 ft
2650.0 ft
2700.0
J61-C1
J61-C1
J62-C1
J62-C1
J63-C1
J63-C1
J64-C1
J64-C1
J65-C1
J65-C1
J66-C1


ft
2750.0 ft
2800.0 ft
2850.0 ft
2900.0 ft
J66-C1
J67-C1
J67-C1
J68-C1
J68-C1
J69-C1
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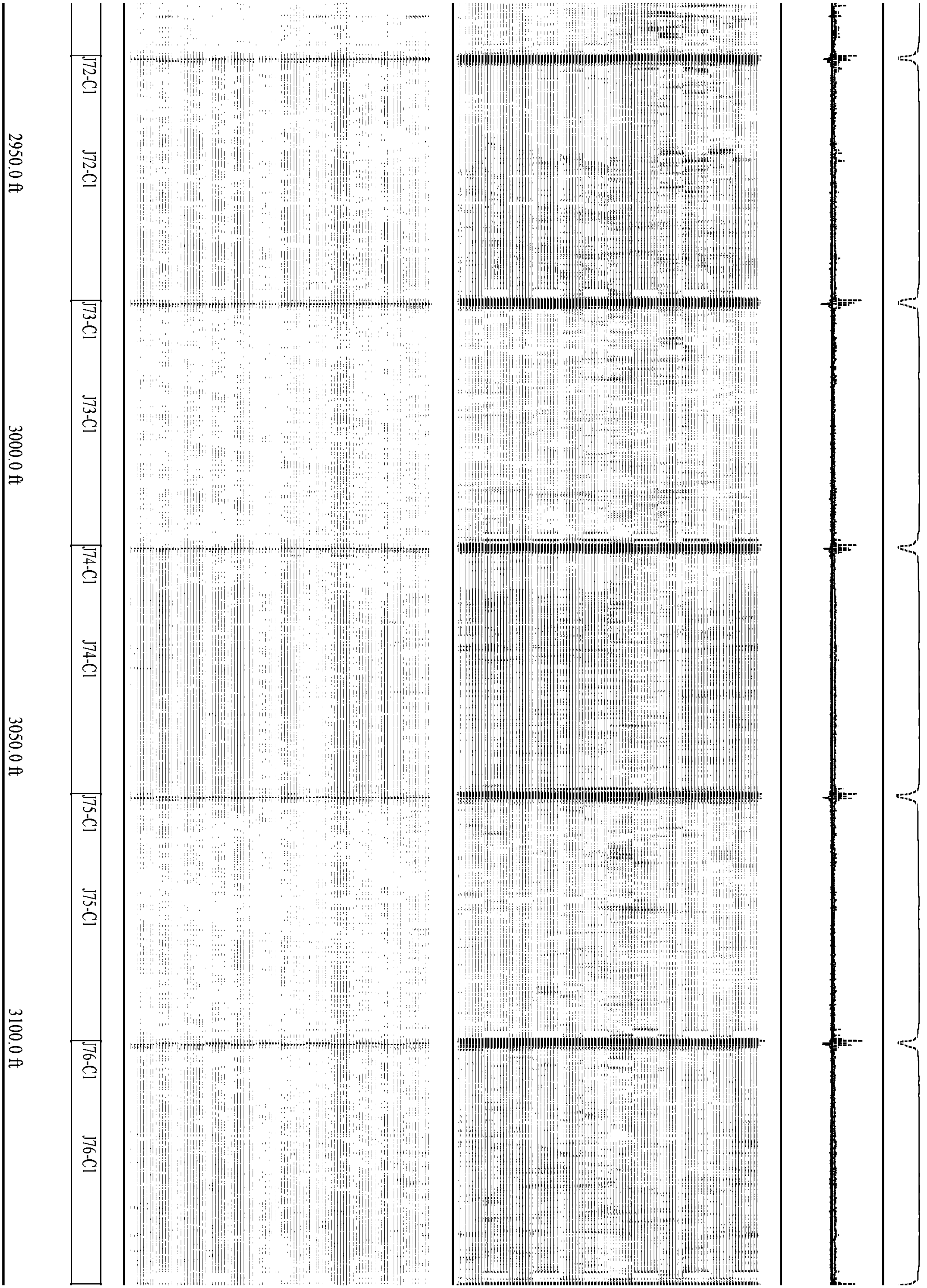
J70-C1
J71-C1


2950.0 ft
3000.0 ft
3050.0 ft
3100.0 ft
J72-C1
J72-C1
J73-C1
J73-C1
J74-C1
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J75-C1
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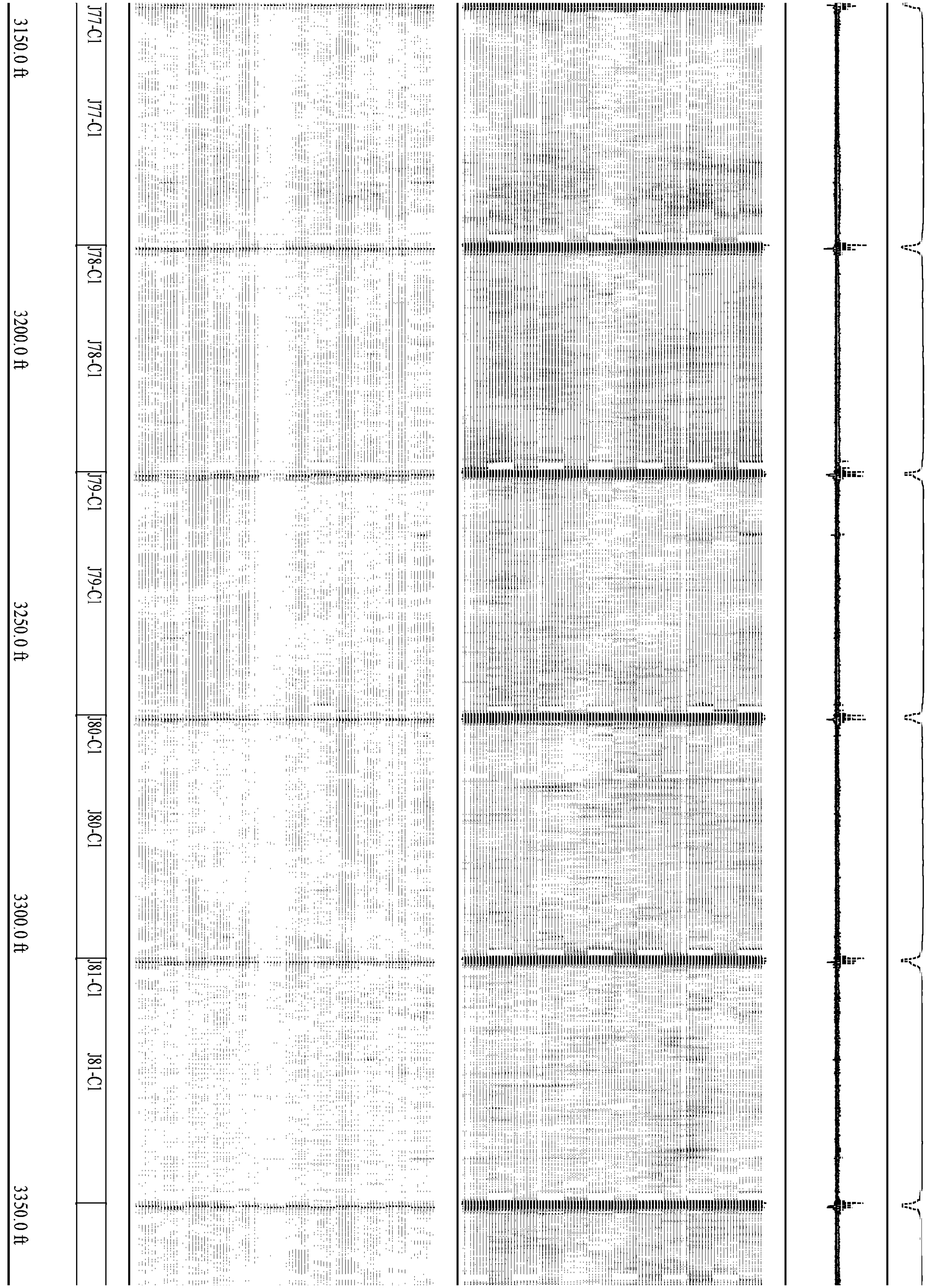
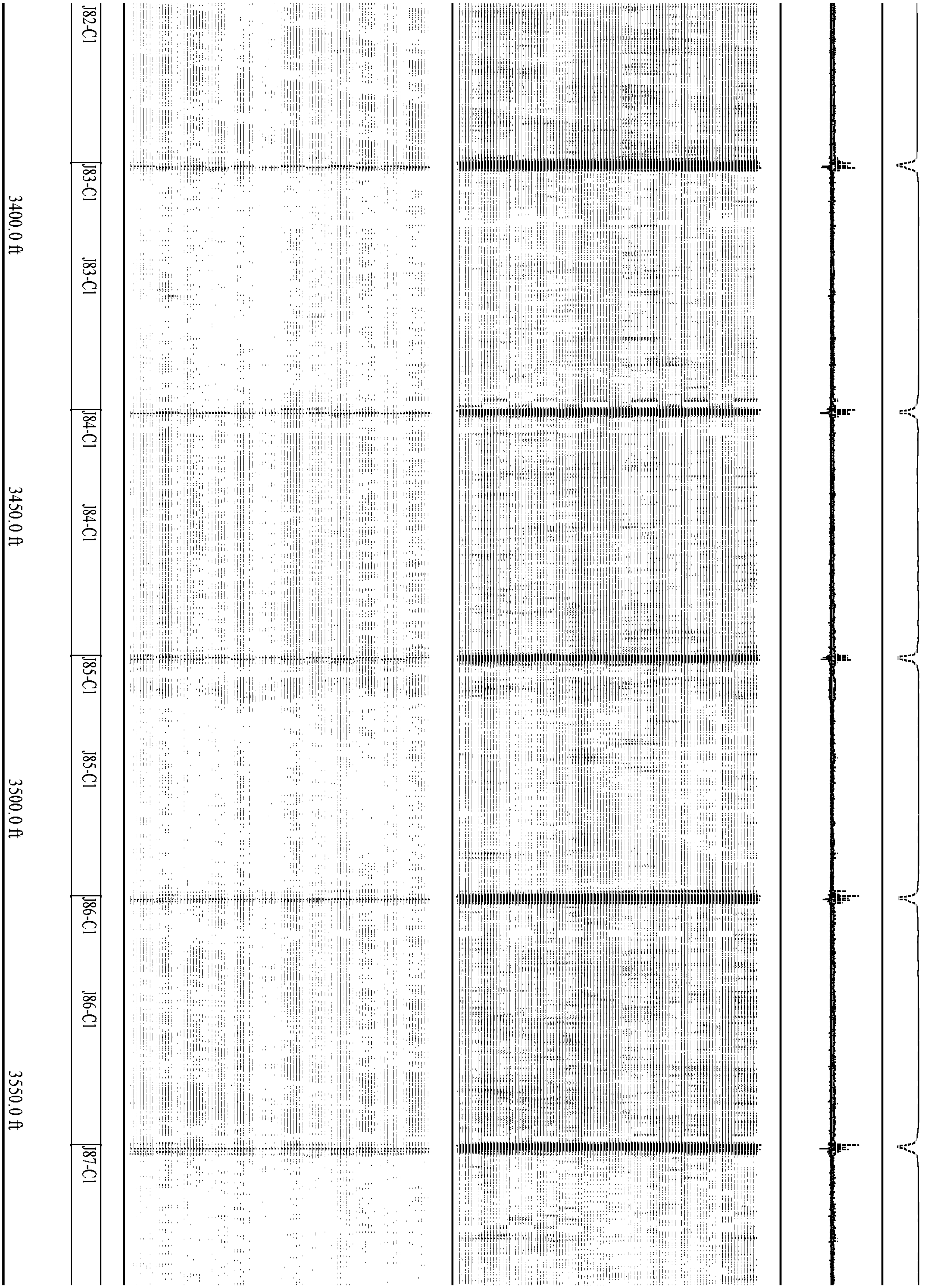
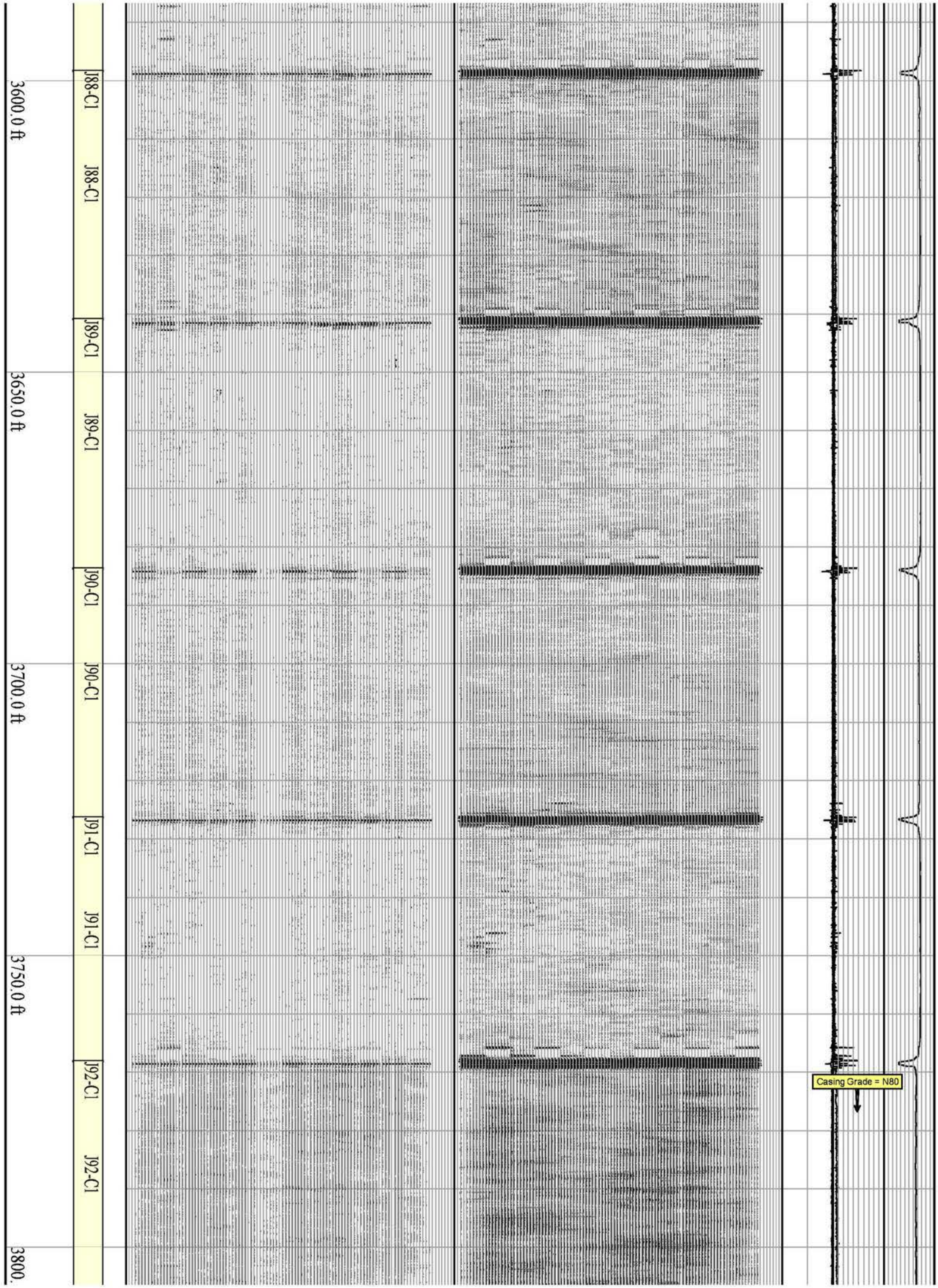
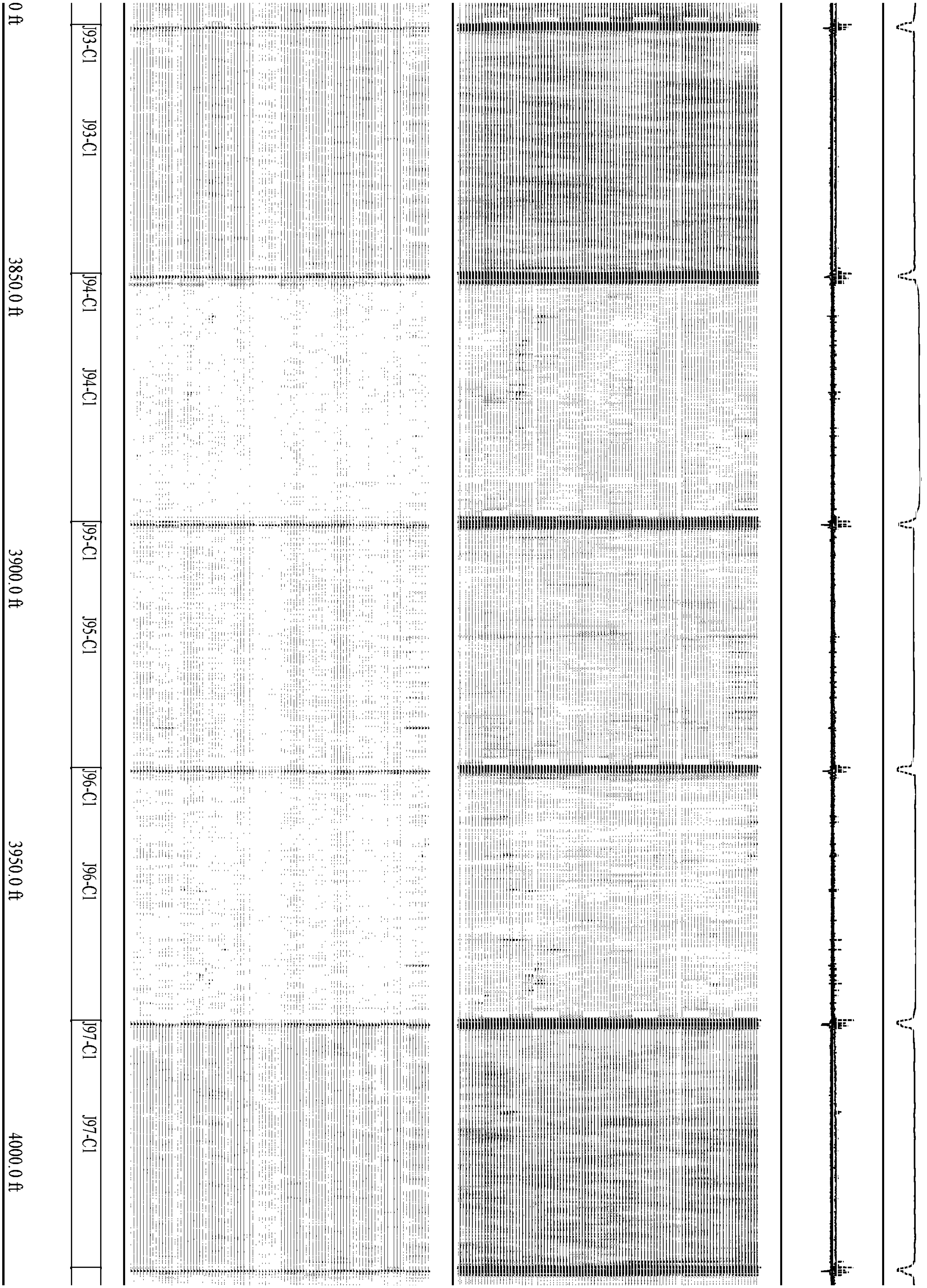
J76-C1
J76-C1

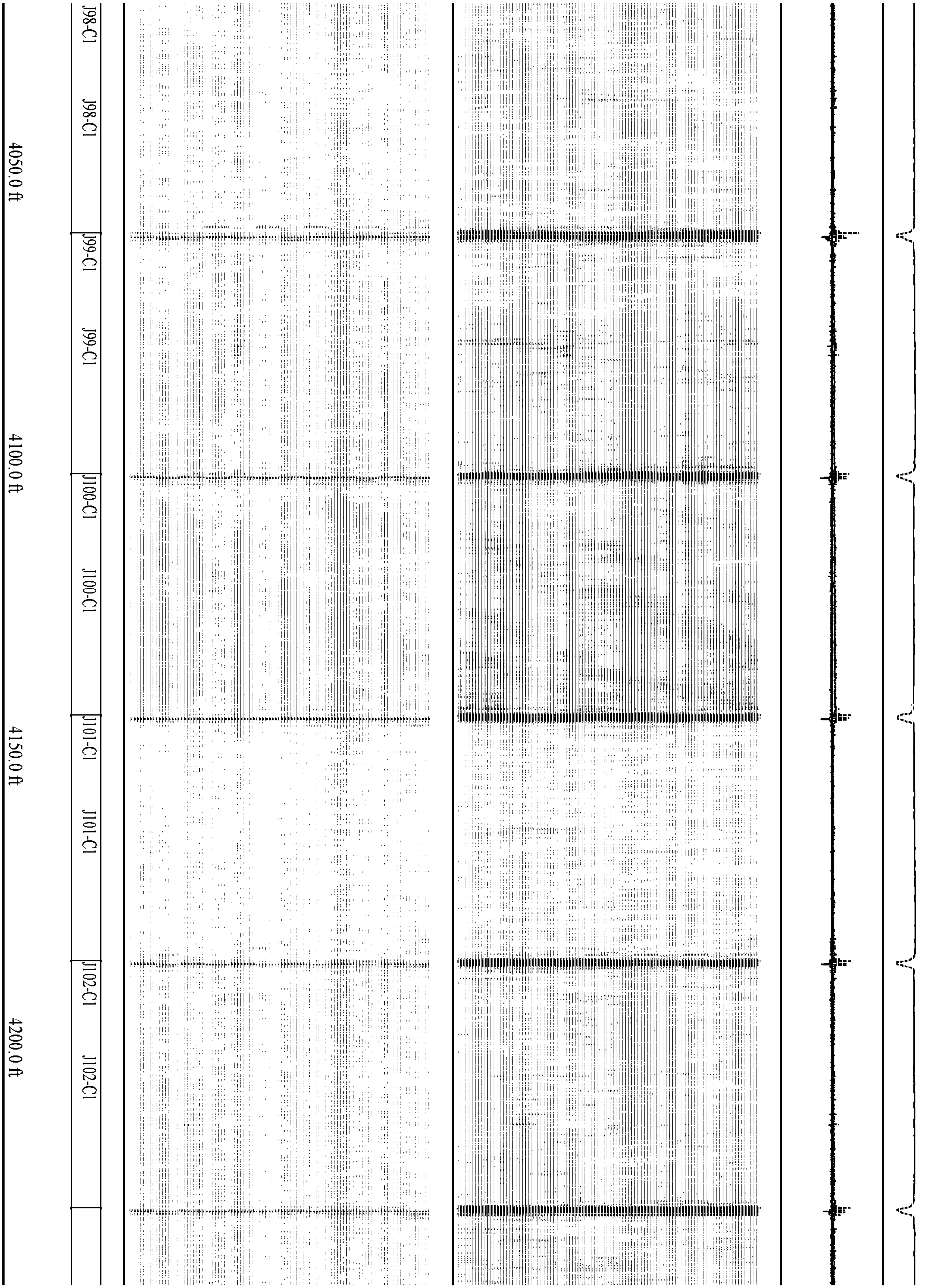

3150.0 ft
3200.0 ft
3250.0 ft
3300.0 ft
3350.0 ft
J77-C1
J77-C1
J78-C1
J78-C1
J79-C1
J79-C1
J80-C1
J80-C1
J81-C1
J81-C1


J82-C1
J83-C1
3400.0 ft
J83-C1
J84-C1
3450.0 ft
J84-C1
J85-C1
J85-C1
3500.0 ft
J86-C1
J86-C1
3550.0 ft
J87-C1

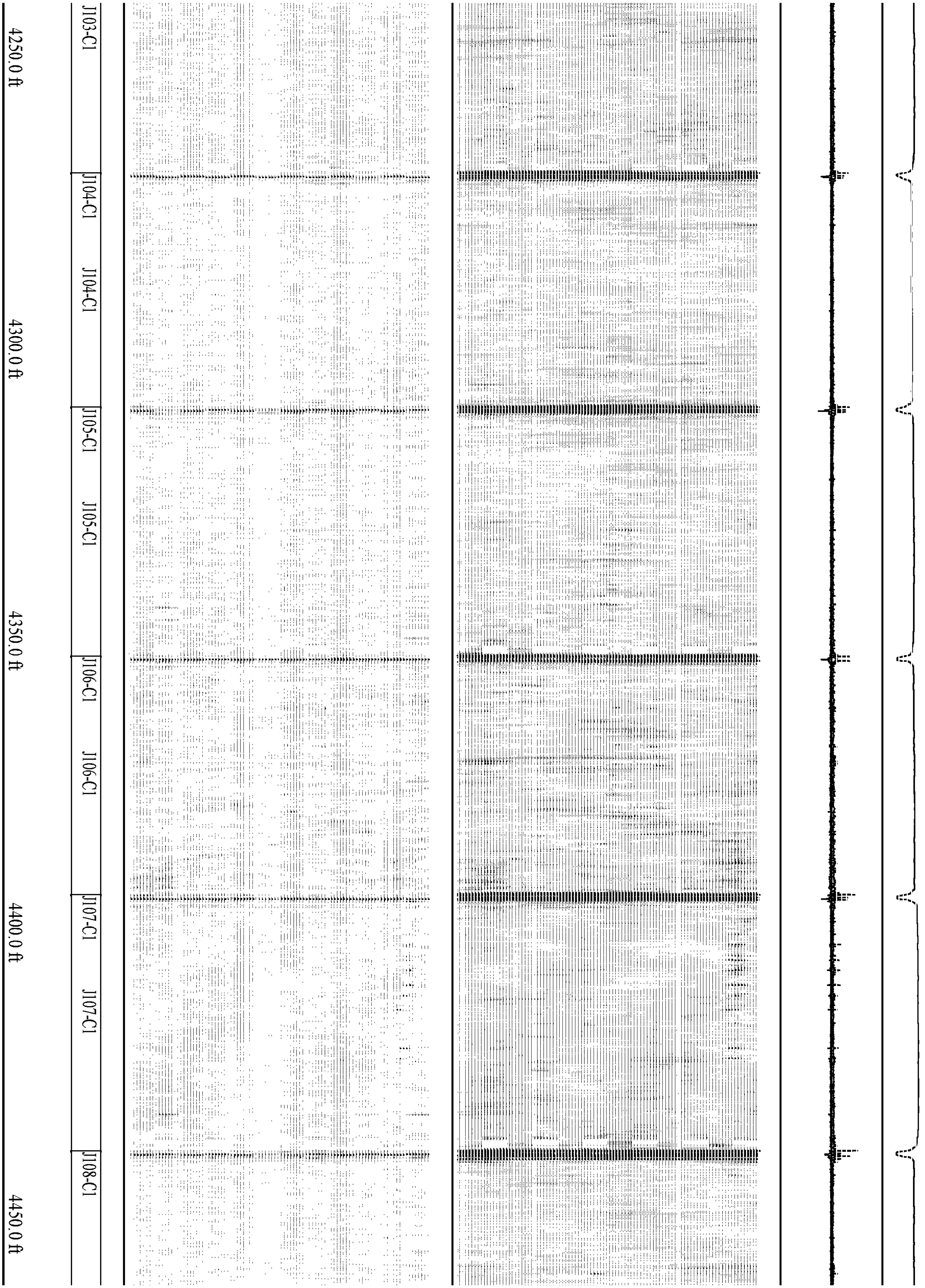

3600.0 ft
3650.0 ft
3700.0 ft
3750.0 ft
3800.
J88-C1
J88-C1
J89-C1
J89-C1
J90-C1
J90-C1
J91-C1
J91-C1
J92-C1
J92-C1
Casing Grade = N80



0 ft
3850.0 ft
3900.0 ft
3950.0 ft
4000.0 ft
J93-C1
J93-C1
J94-C1
J94-C1
J95-C1
J95-C1
J96-C1
J96-C1
J97-C1
J97-C1



J98-C1
J98-C1
4050.0 ft
J99-C1
J99-C1
4100.0 ft
J100-C1
J100-C1
4150.0 ft
J101-C1
J101-C1
J102-C1
4200.0 ft
J102-C1


4250.0 ft
4300.0 ft
4350.0 ft
4400.0 ft
4450.0 ft
J103-C1
J104-C1
J104-C1
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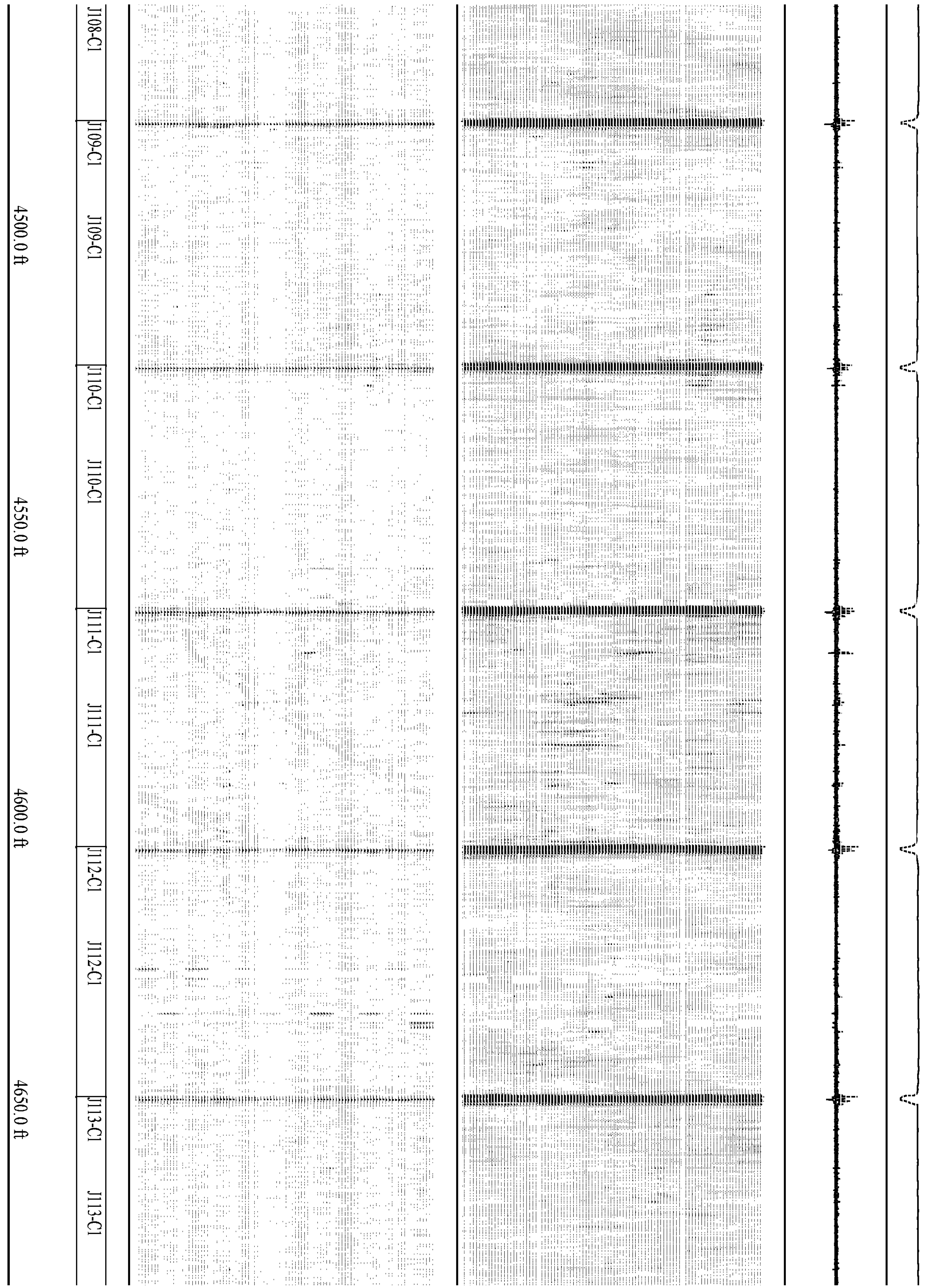
J105-C1
J106-C1
J106-C1
J107-C1
J107-C1
J108-C1


4500.0 ft
4550.0 ft
4600.0 ft
4650.0 ft
J108-C1
J109-C1
J109-C1
J110-C1
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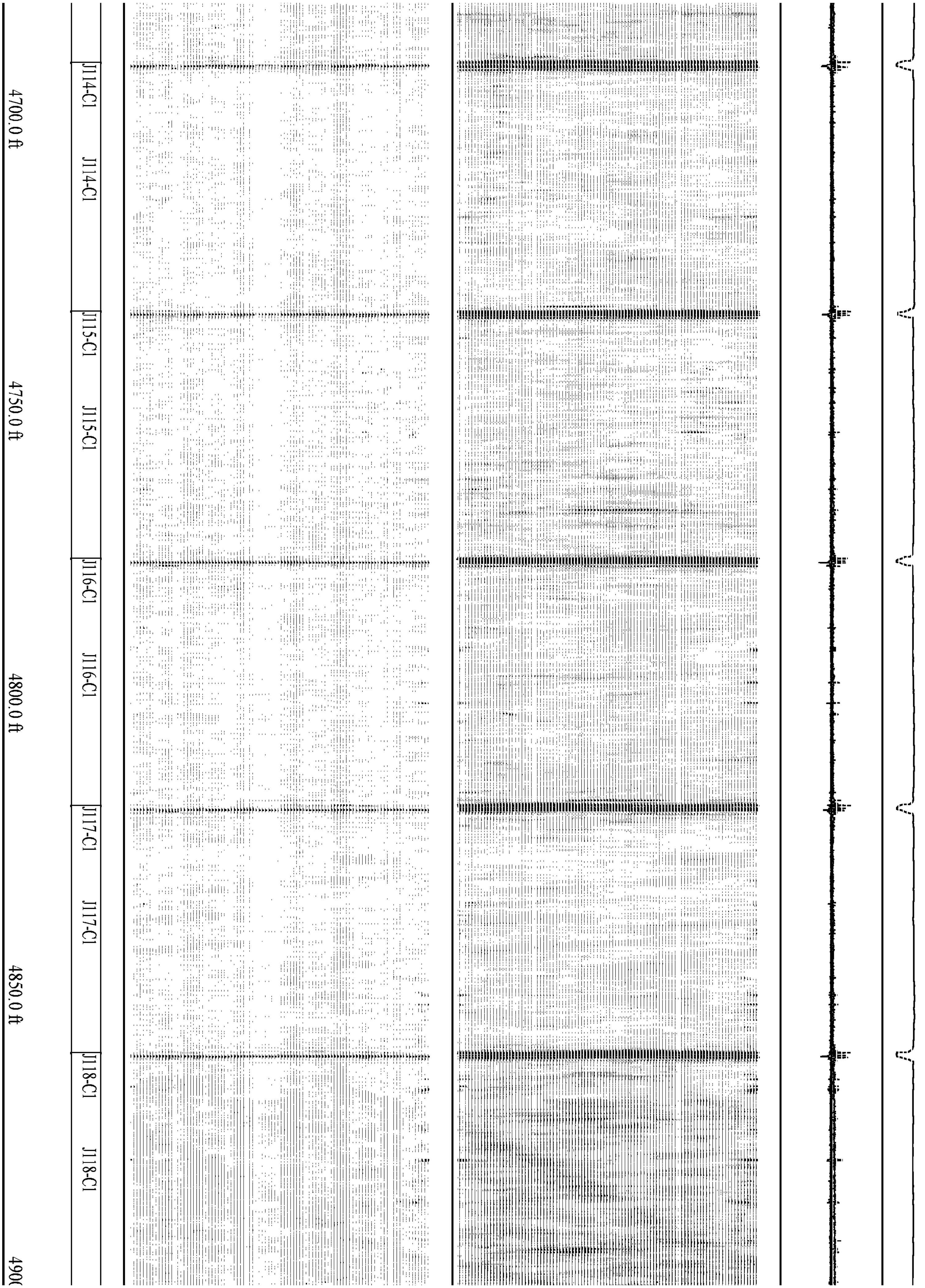
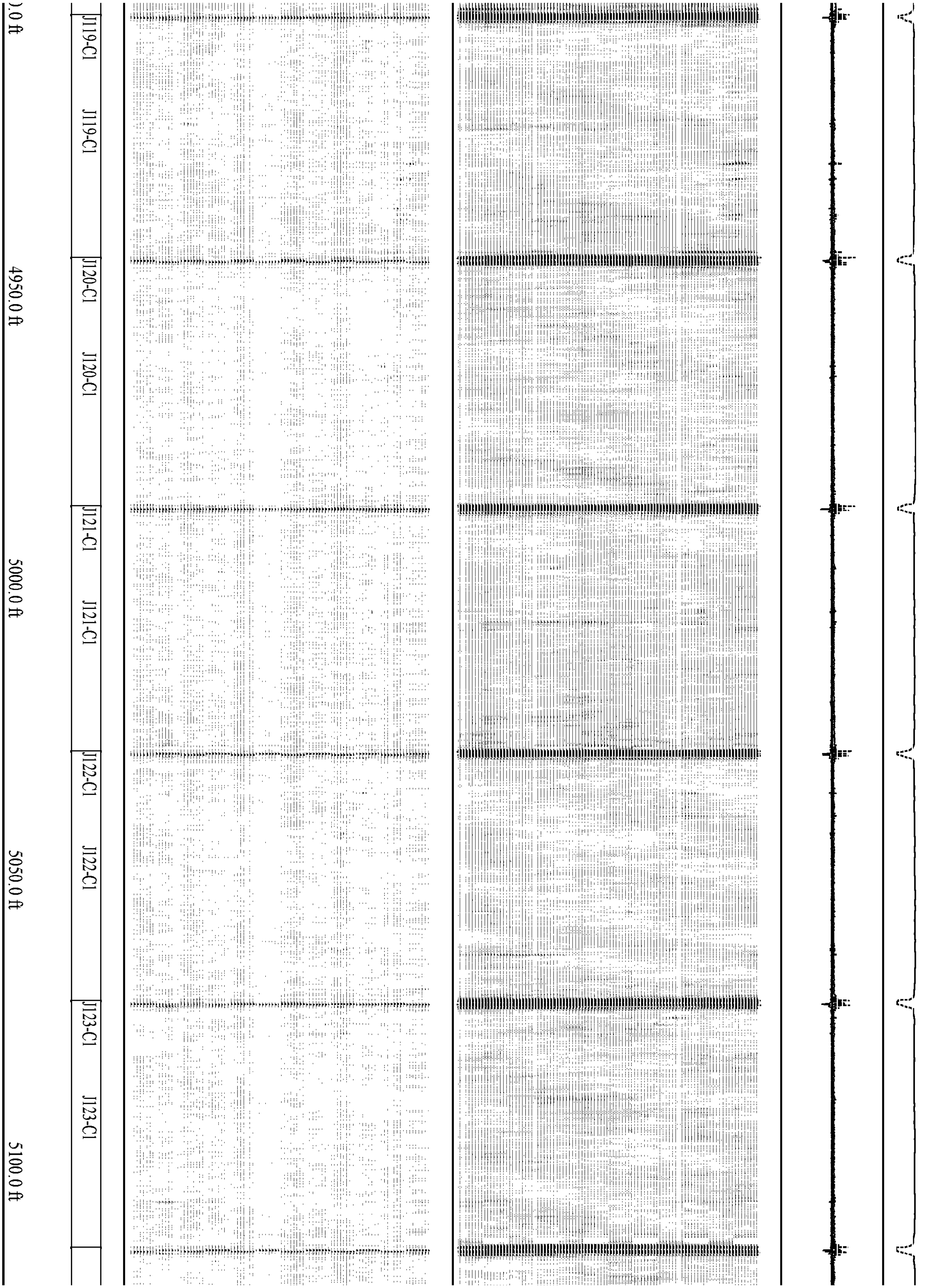
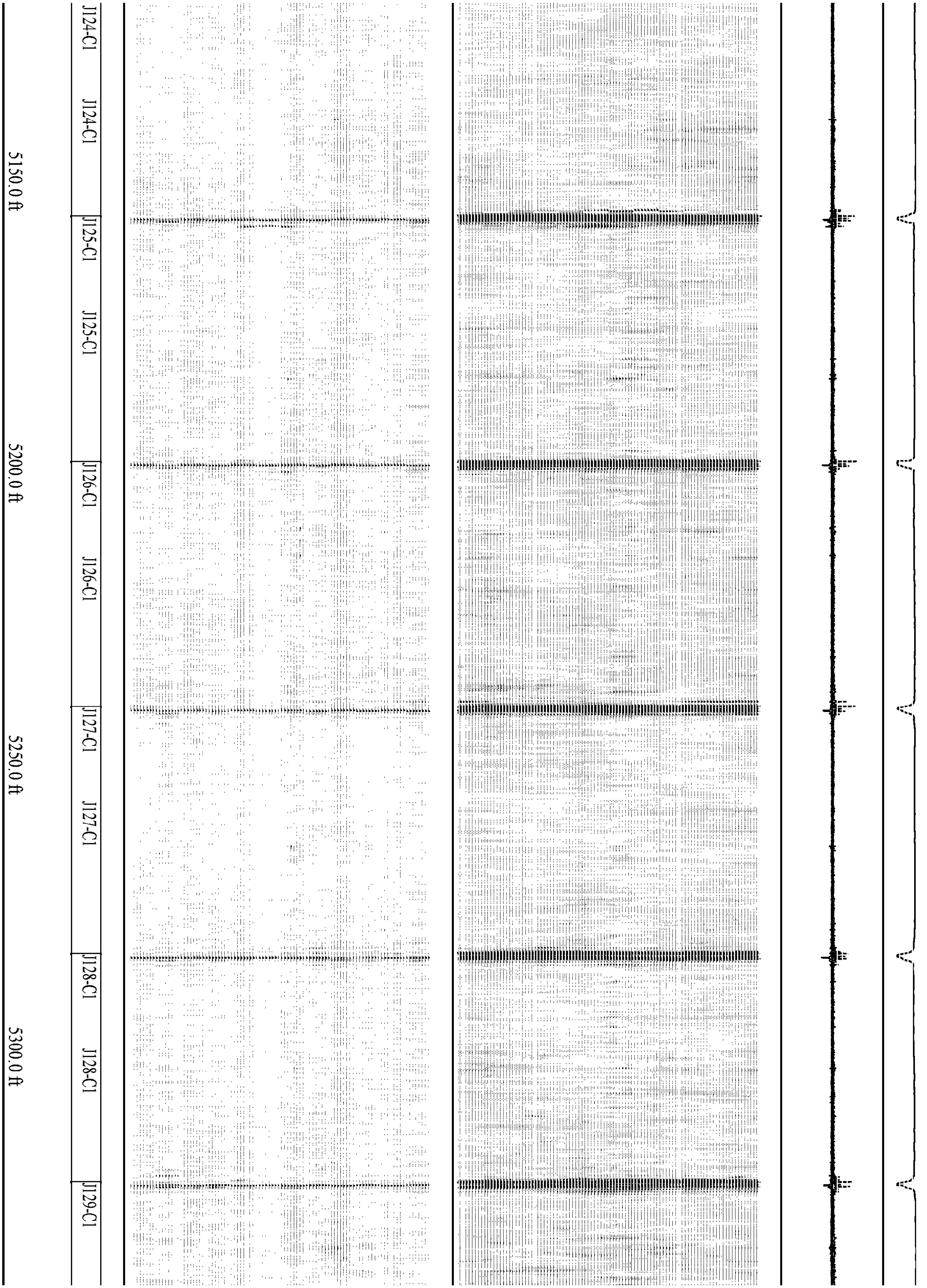
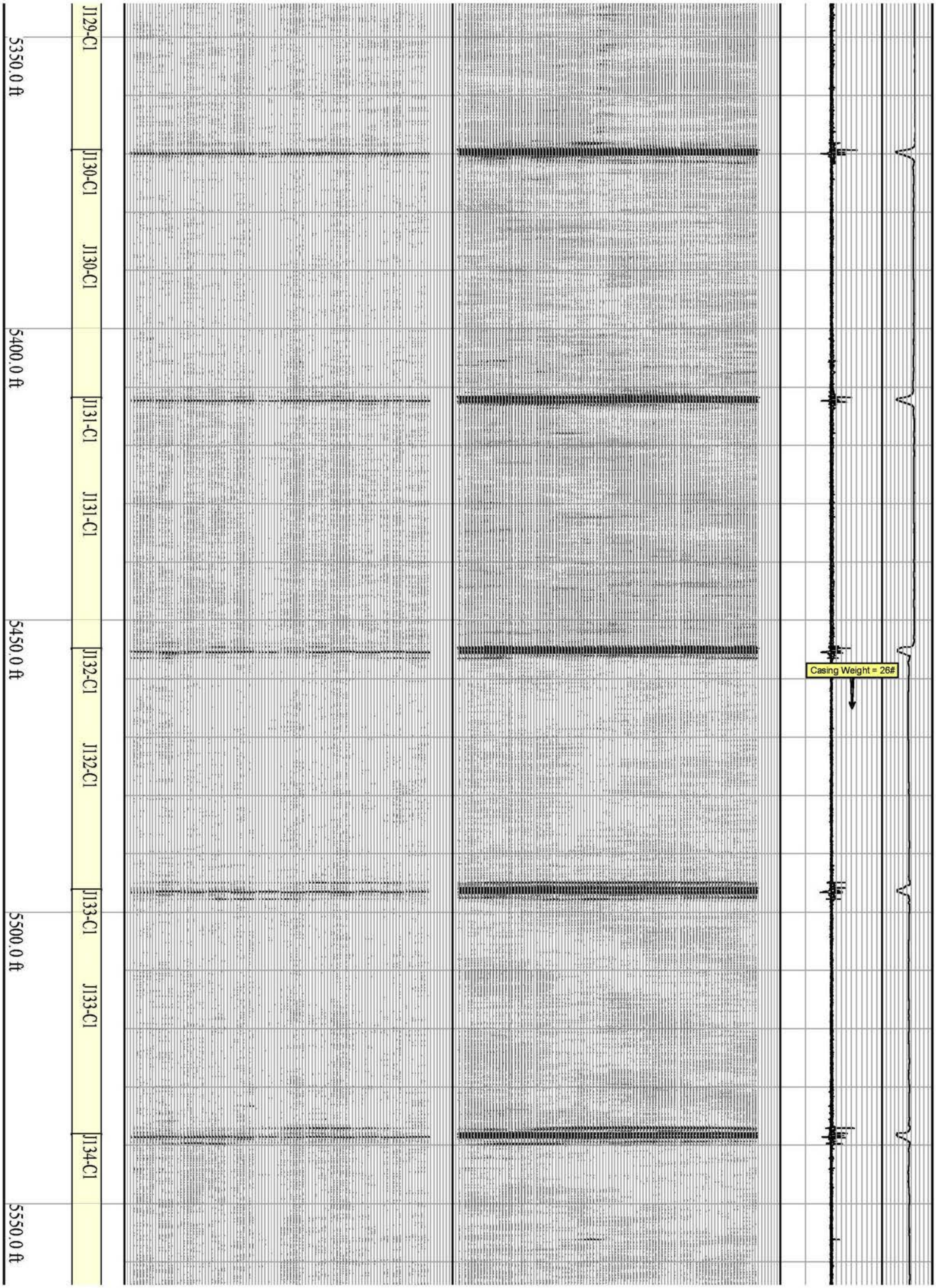
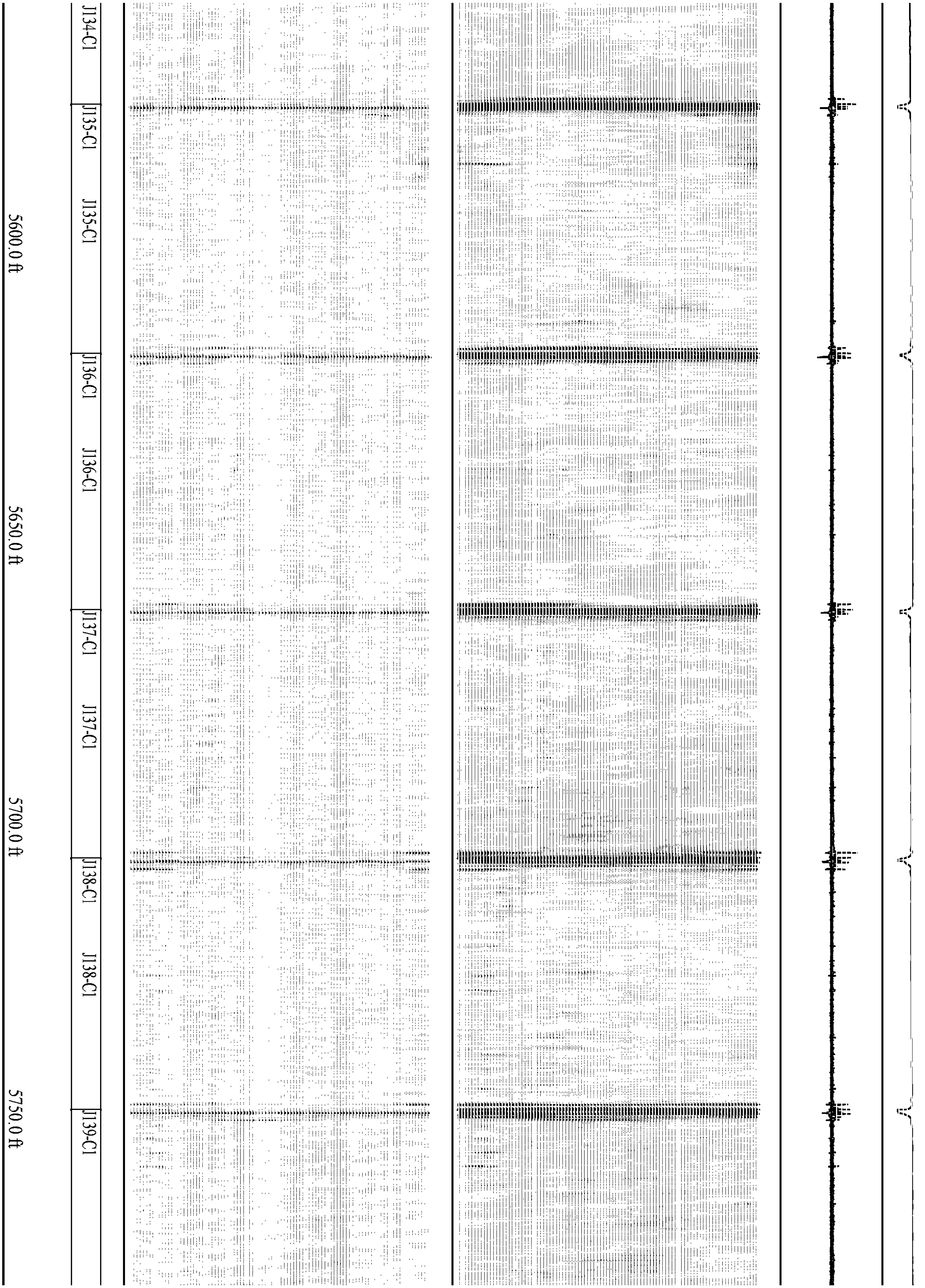
J111-C1
J111-C1
J112-C1
J112-C1
J113-C1
J113-C1

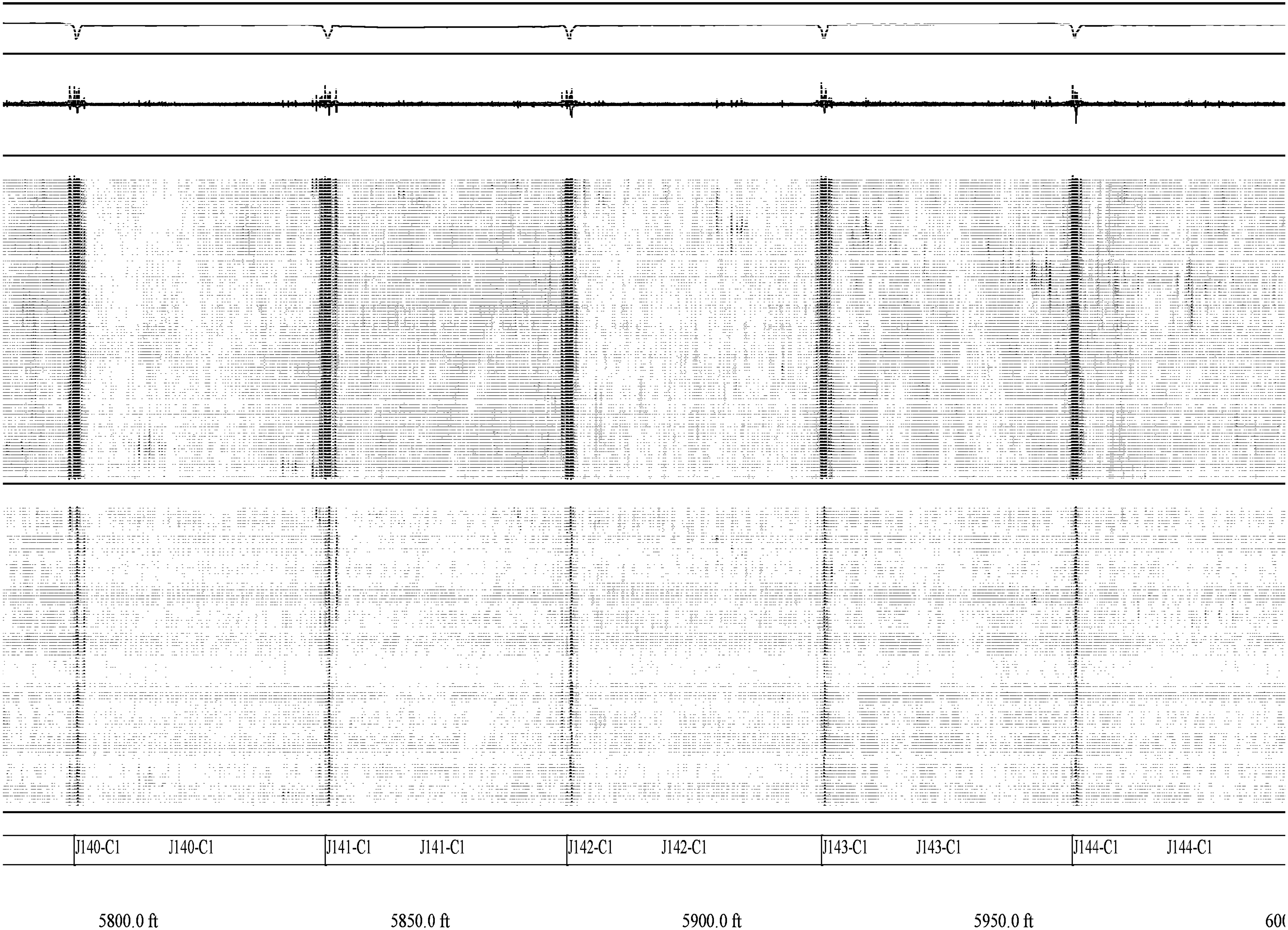

4700.0 ft
J114-C1
J114-C1
4750.0 ft
J115-C1
J115-C1
4800.0 ft
J116-C1
J116-C1
4850.0 ft
J117-C1
J117-C1
J118-C1
J118-C1

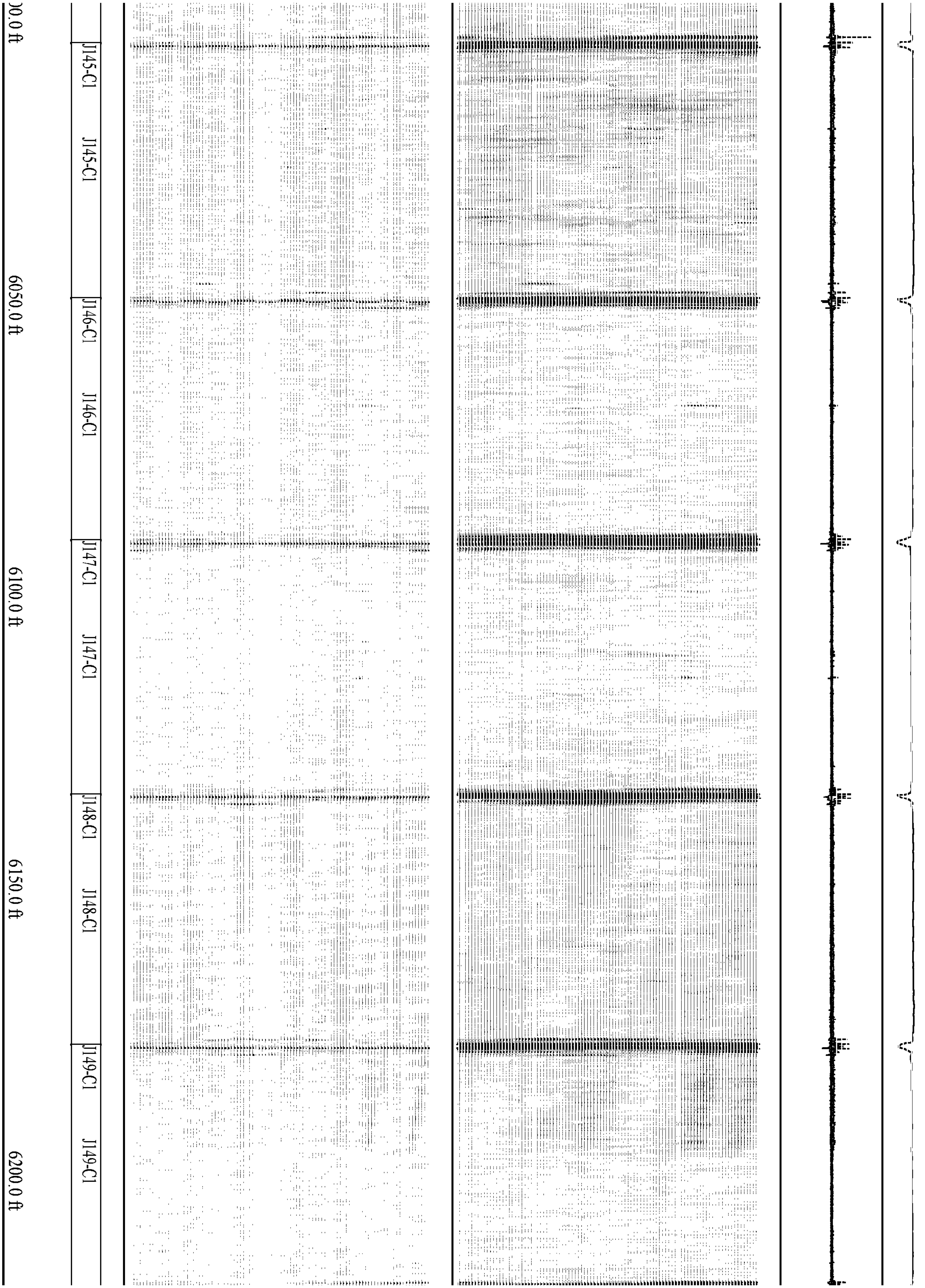

4950.0 ft
5000.0 ft
5050.0 ft
5100.0 ft
J119-C1
J119-C1
J120-C1
J120-C1
J121-C1
J121-C1
J122-C1
J122-C1
J123-C1
J123-C1

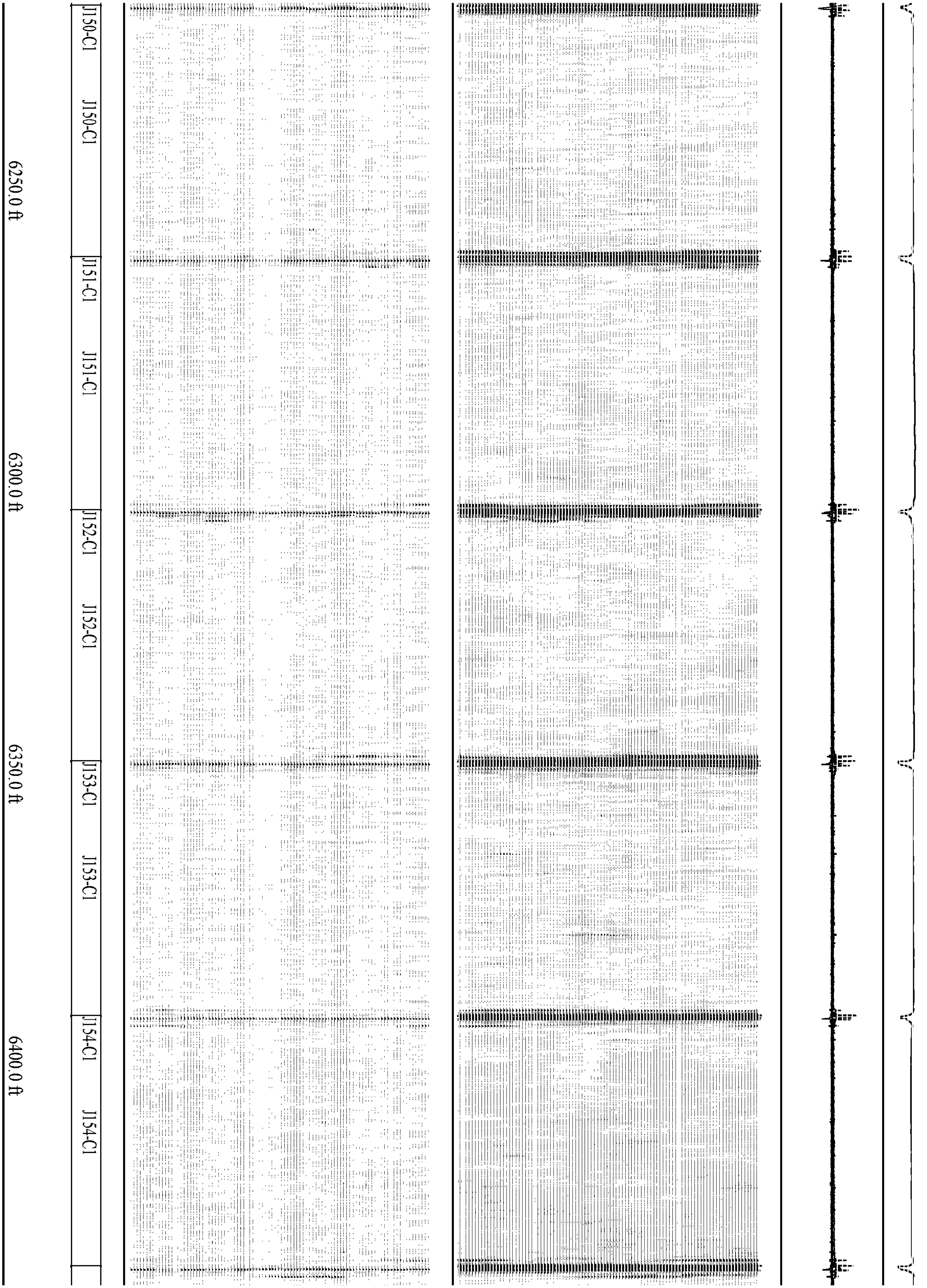

5150.0 ft
5200.0 ft
5250.0 ft
5300.0 ft
J124-C1
J124-C1
J125-C1
J125-C1
J126-C1
J126-C1
J127-C1
J127-C1
J128-C1
J128-C1
J129-C1

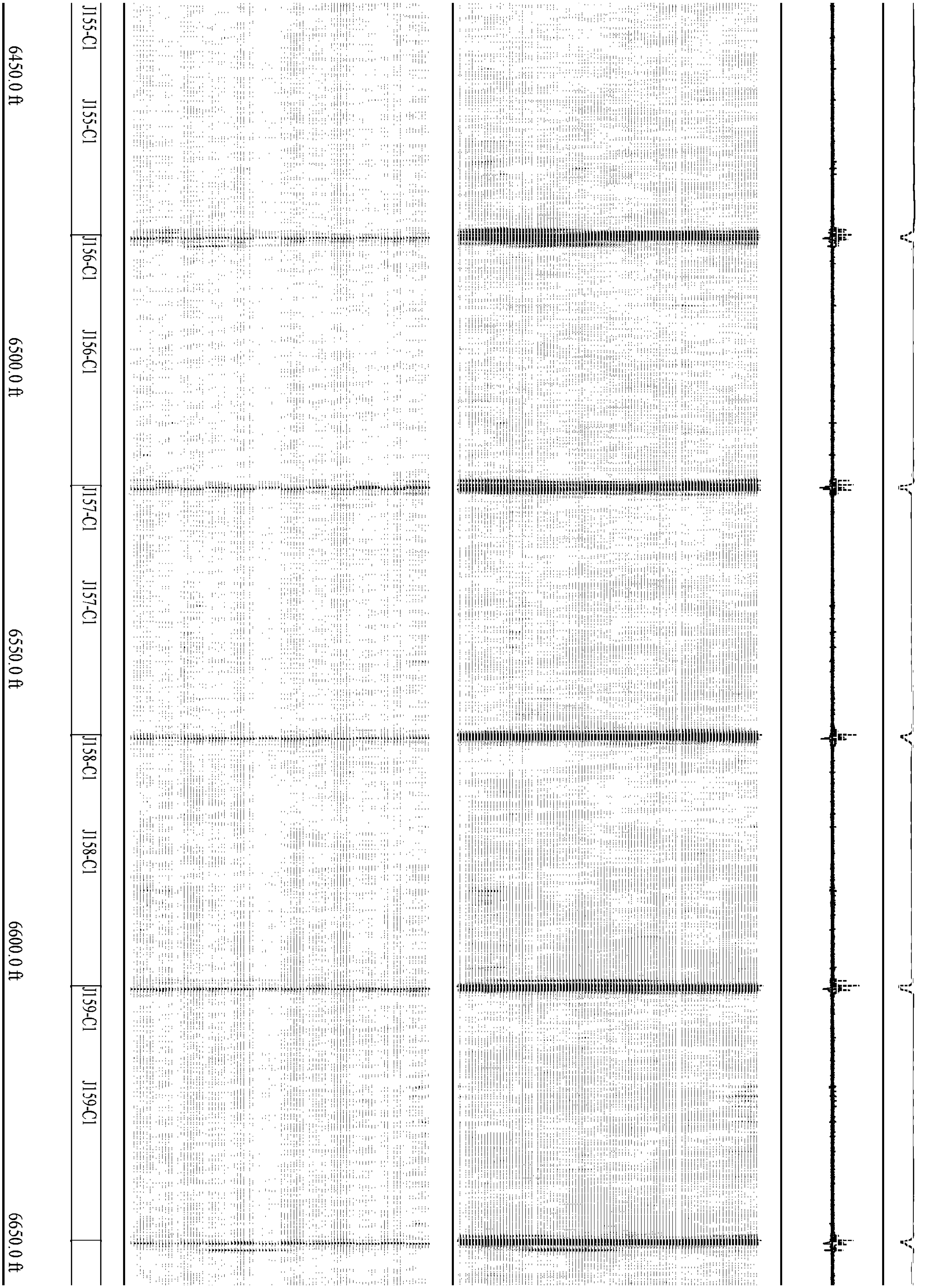

5350.0 ft
5400.0 ft
5450.0 ft
5500.0 ft
5550.0 ft
J129-C1
J130-C1
J130-C1
J131-C1
J131-C1
J132-C1
J132-C1
J133-C1
J133-C1
J134-C1
Casing Weight = 26#


J134-C1
J135-C1
J135-C1
5600.0 ft
J136-C1
J136-C1
5650.0 ft
J137-C1
J137-C1
5700.0 ft
J138-C1
J138-C1
5750.0 ft
J139-C1


J140-C1
J140-C1
J141-C1
J141-C1
J142-C1
J142-C1
J143-C1
J143-C1
J144-C1
J144-C1
5800.0 ft
5850.0 ft
5900.0 ft
5950.0 ft


6050.0 ft
6100.0 ft
6150.0 ft
6200.0 ft
J145-C1
J145-C1
J146-C1
J146-C1
J147-C1
J147-C1
J148-C1
J148-C1
J149-C1
J149-C1


J150-C1
J150-C1
6250.0 ft
J151-C1
J151-C1
6300.0 ft
J152-C1
J152-C1
6350.0 ft
J153-C1
J153-C1
6400.0 ft
J154-C1
J154-C1


6450.0 ft
6500.0 ft
6550.0 ft
6600.0 ft
6650.0 ft
J155-C1
J155-C1
J156-C1
J156-C1
J157-C1
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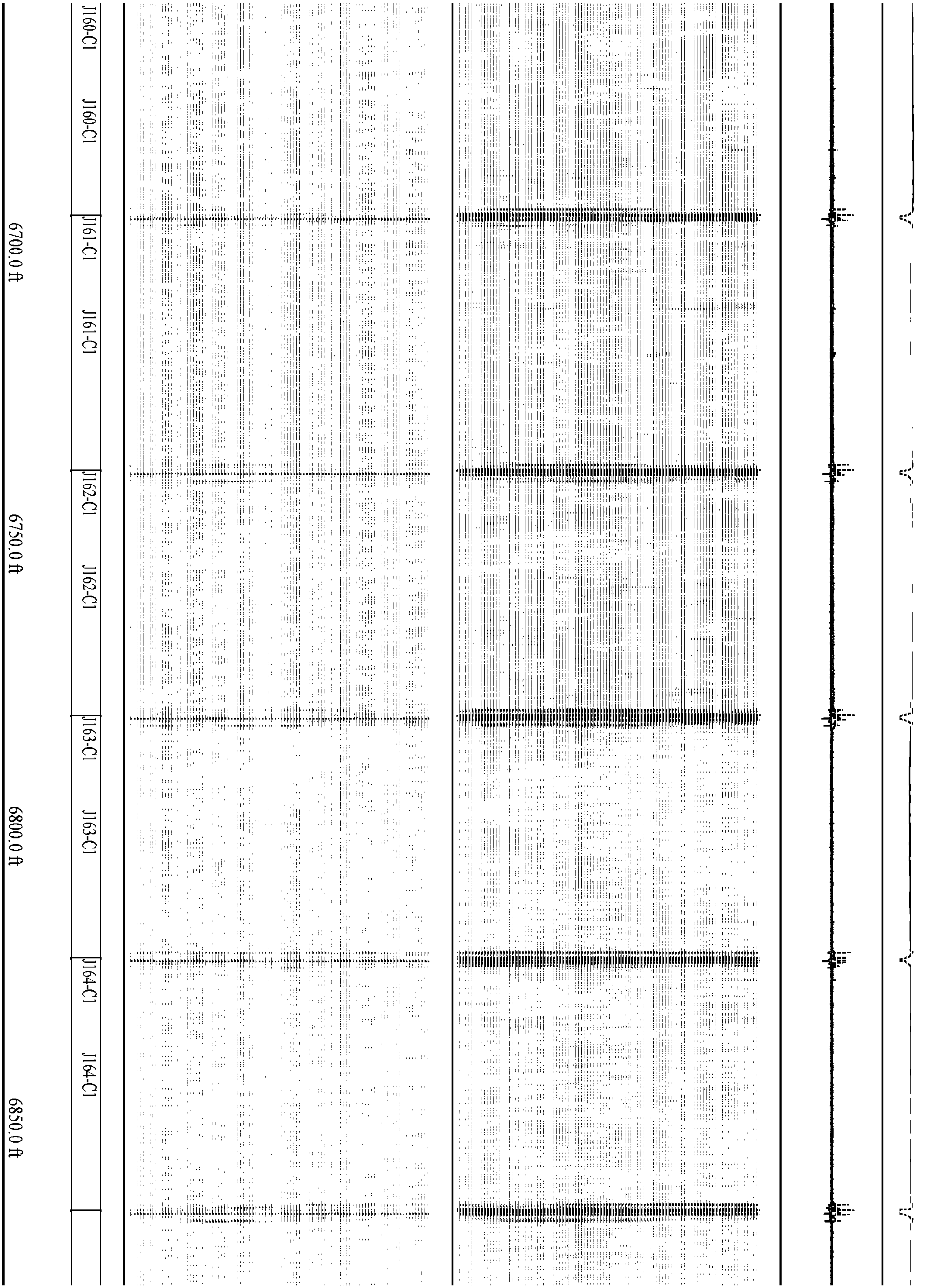
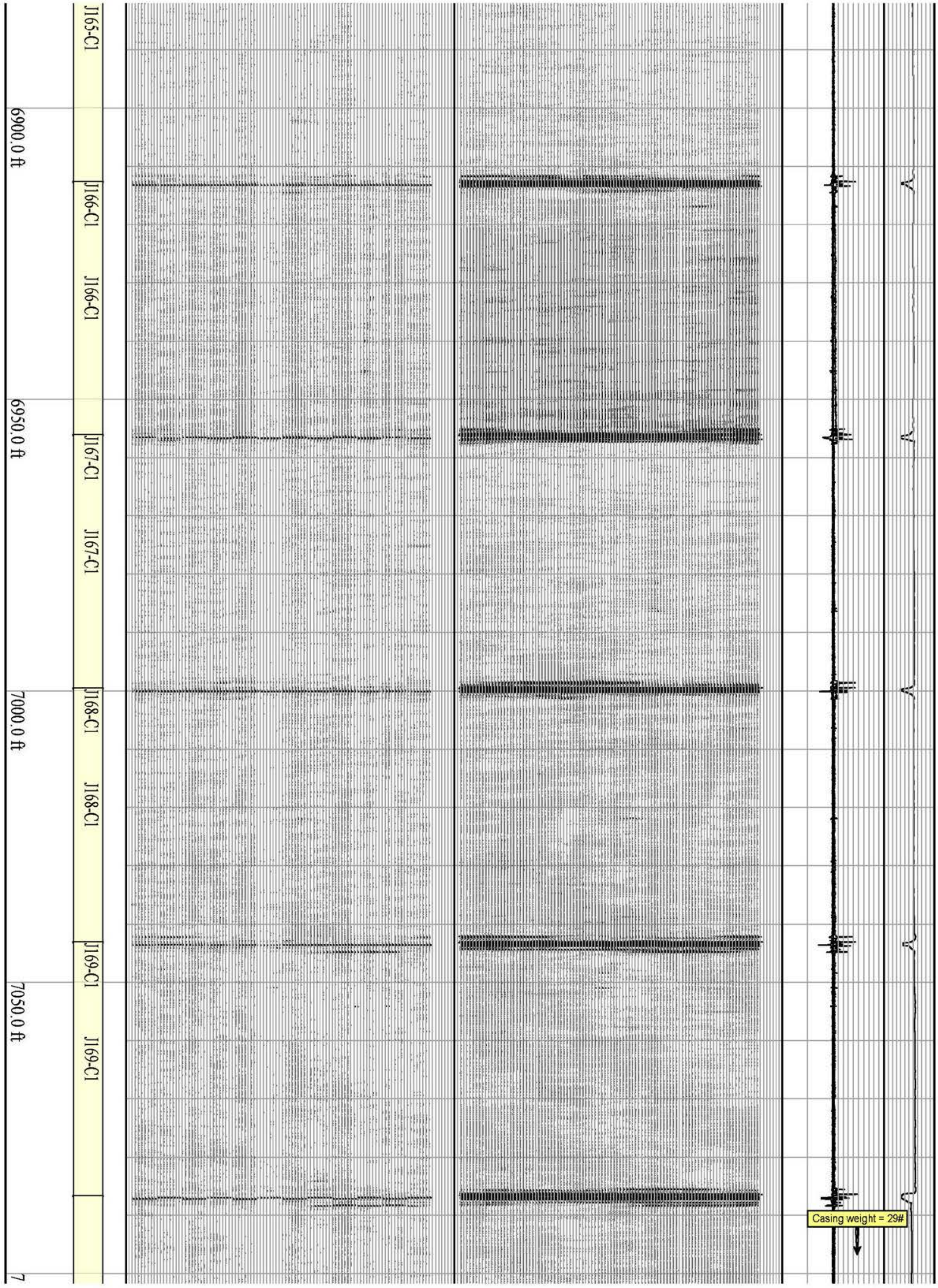
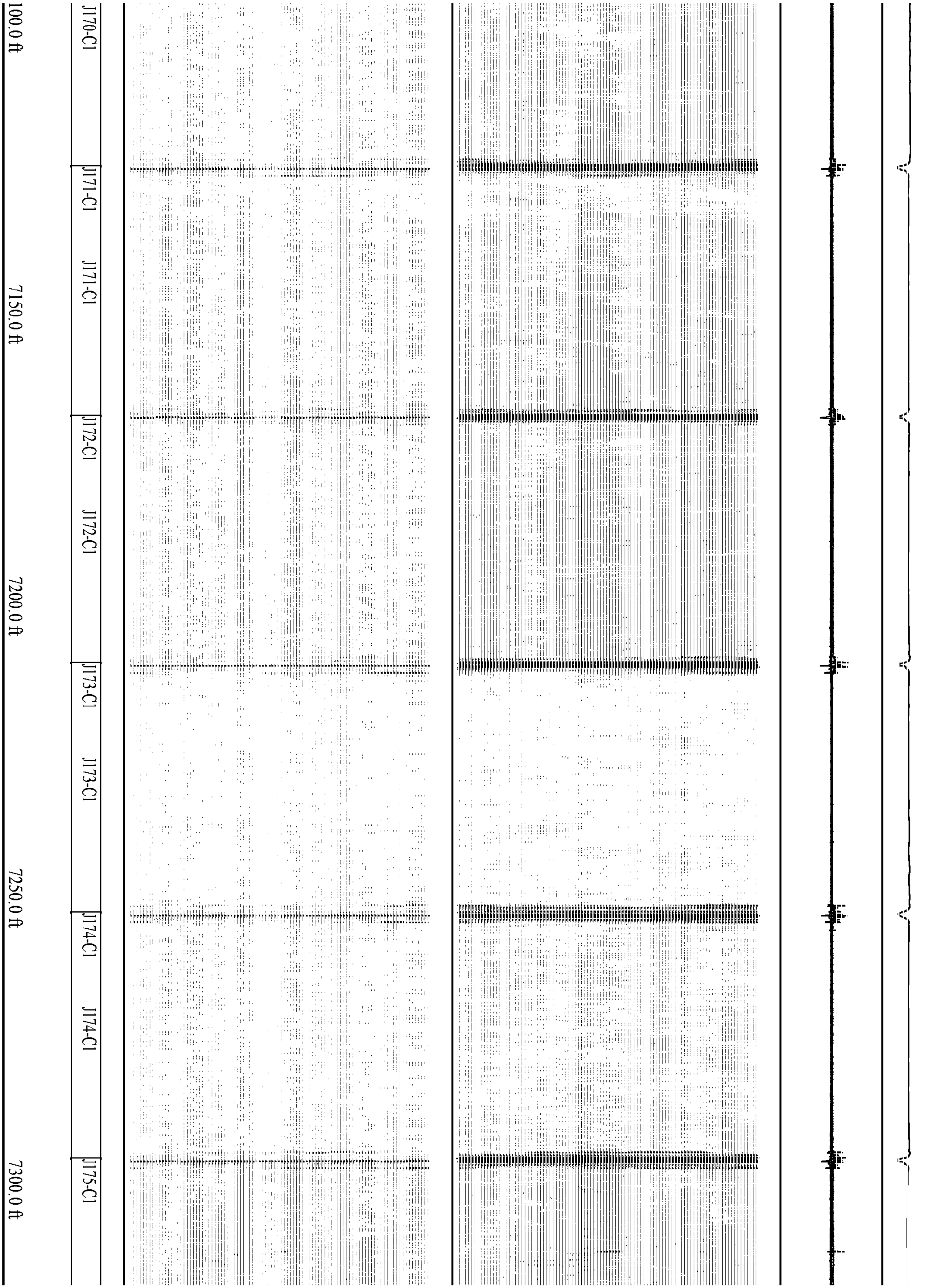
J158-C1
J158-C1
J159-C1
J159-C1

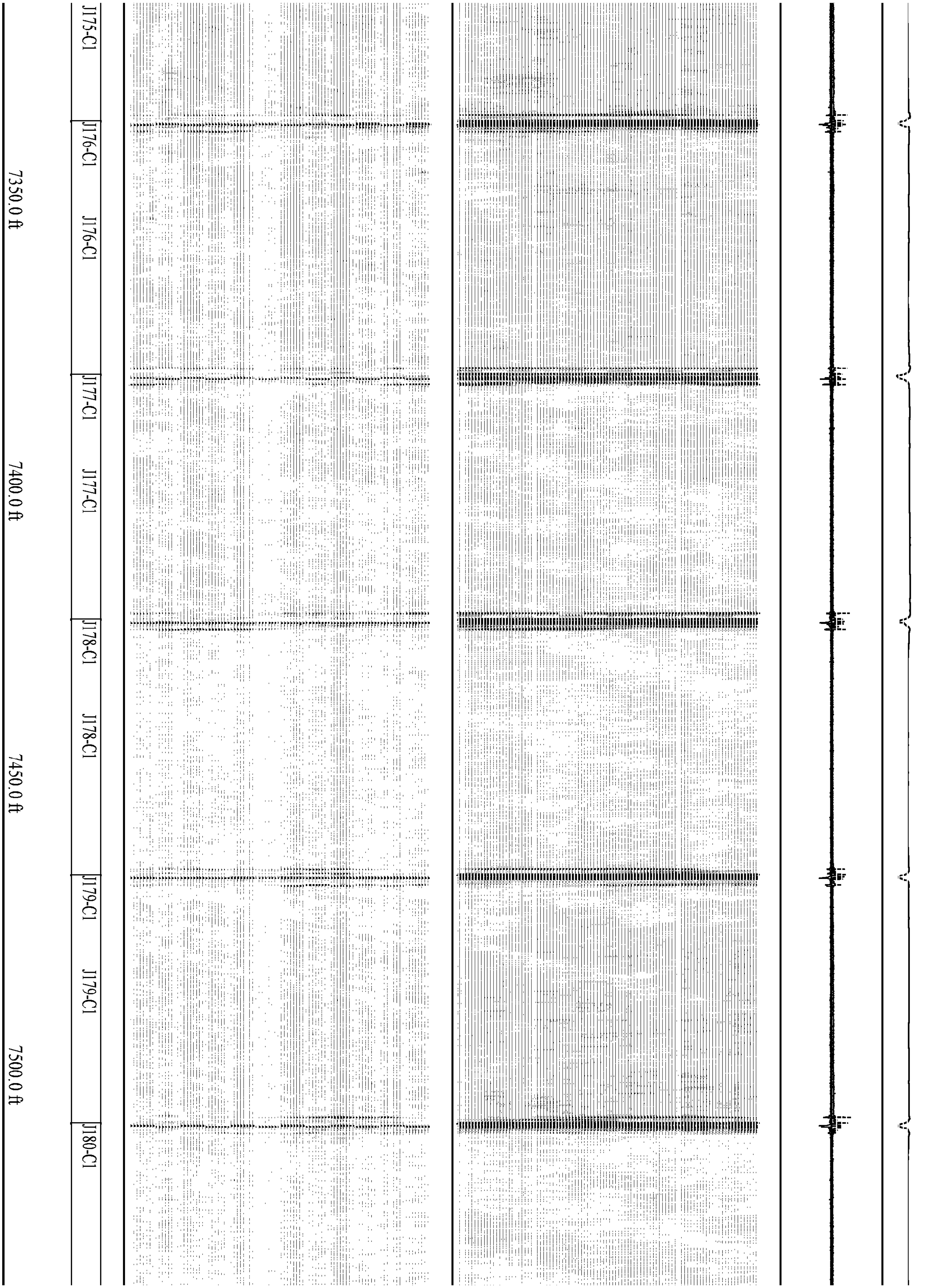

J160-C1
J160-C1
6700.0 ft
J161-C1
J161-C1
J162-C1
6750.0 ft
J162-C1
J163-C1
6800.0 ft
J163-C1
J164-C1
J164-C1
6850.0 ft

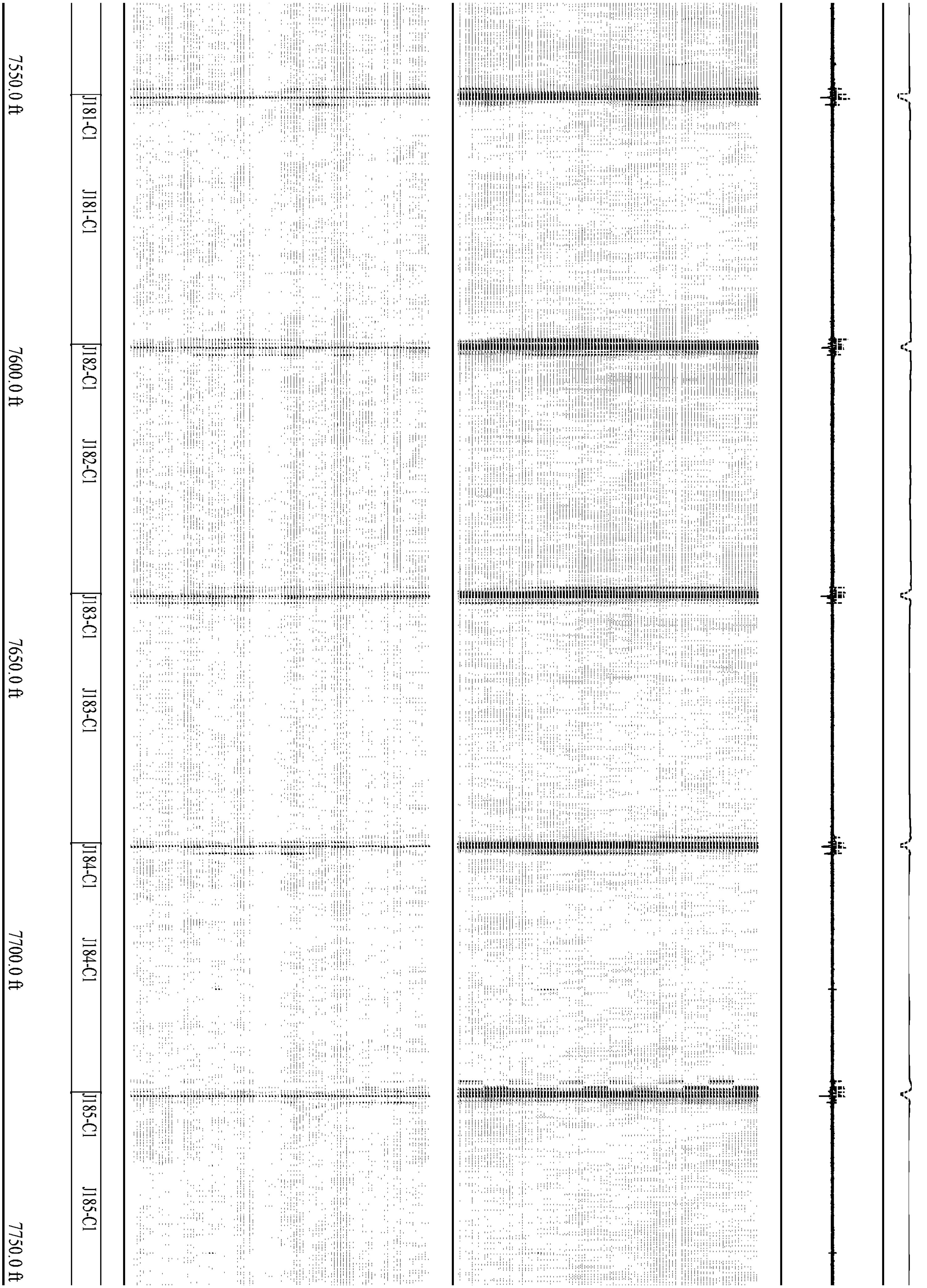


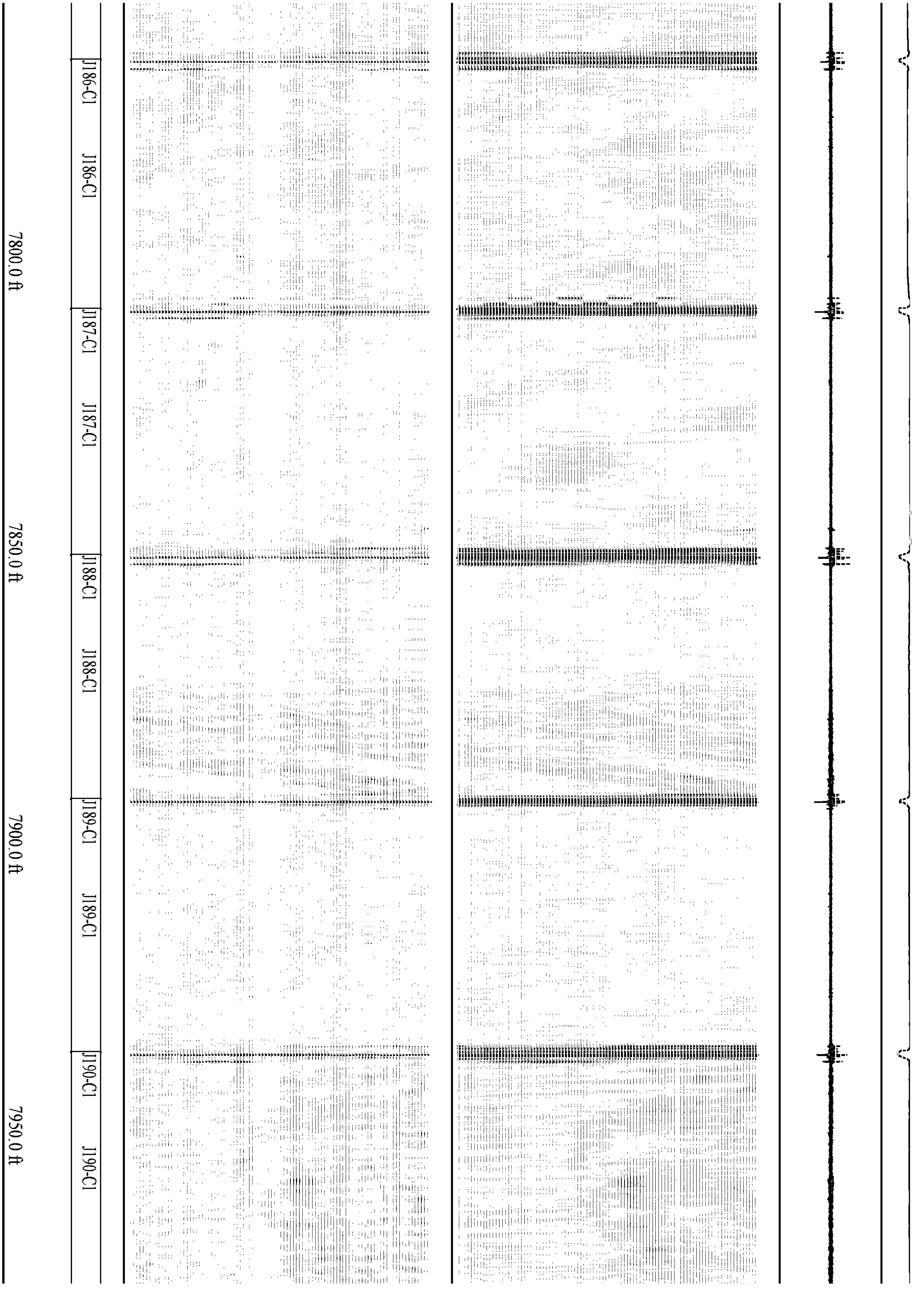
6900.0 ft
6950.0 ft
7000.0 ft
7050.0 ft
J165-C1
J166-C1
J166-C1
J167-C1
J167-C1
J168-C1
J168-C1
J169-C1
J169-C1
Casing weight = 29#



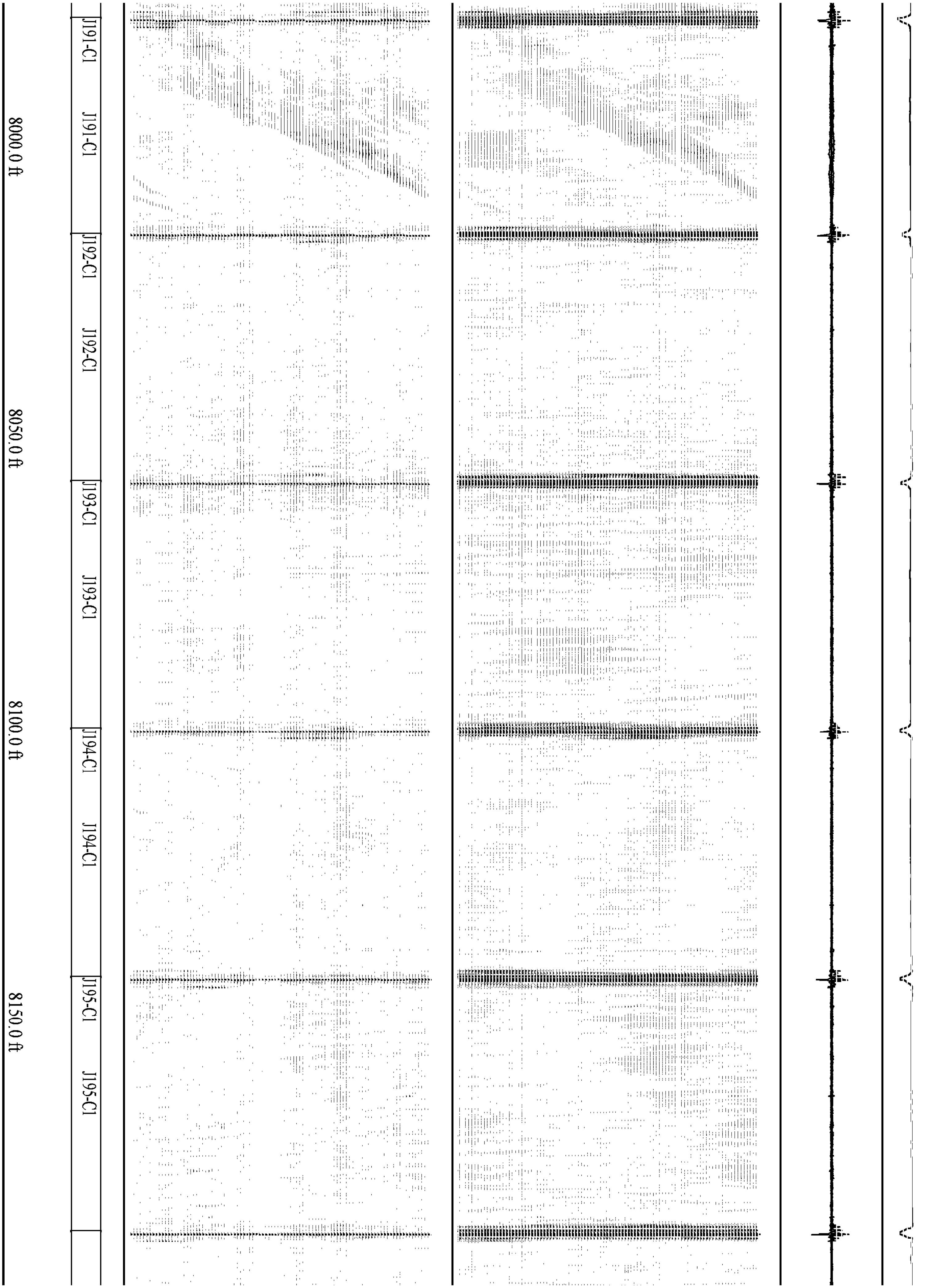
100.0 ft
7150.0 ft
7200.0 ft
7250.0 ft
7300.0 ft
J170-C1
J171-C1
J171-C1
J172-C1
J172-C1
J173-C1
J173-C1
J174-C1
J174-C1
J175-C1

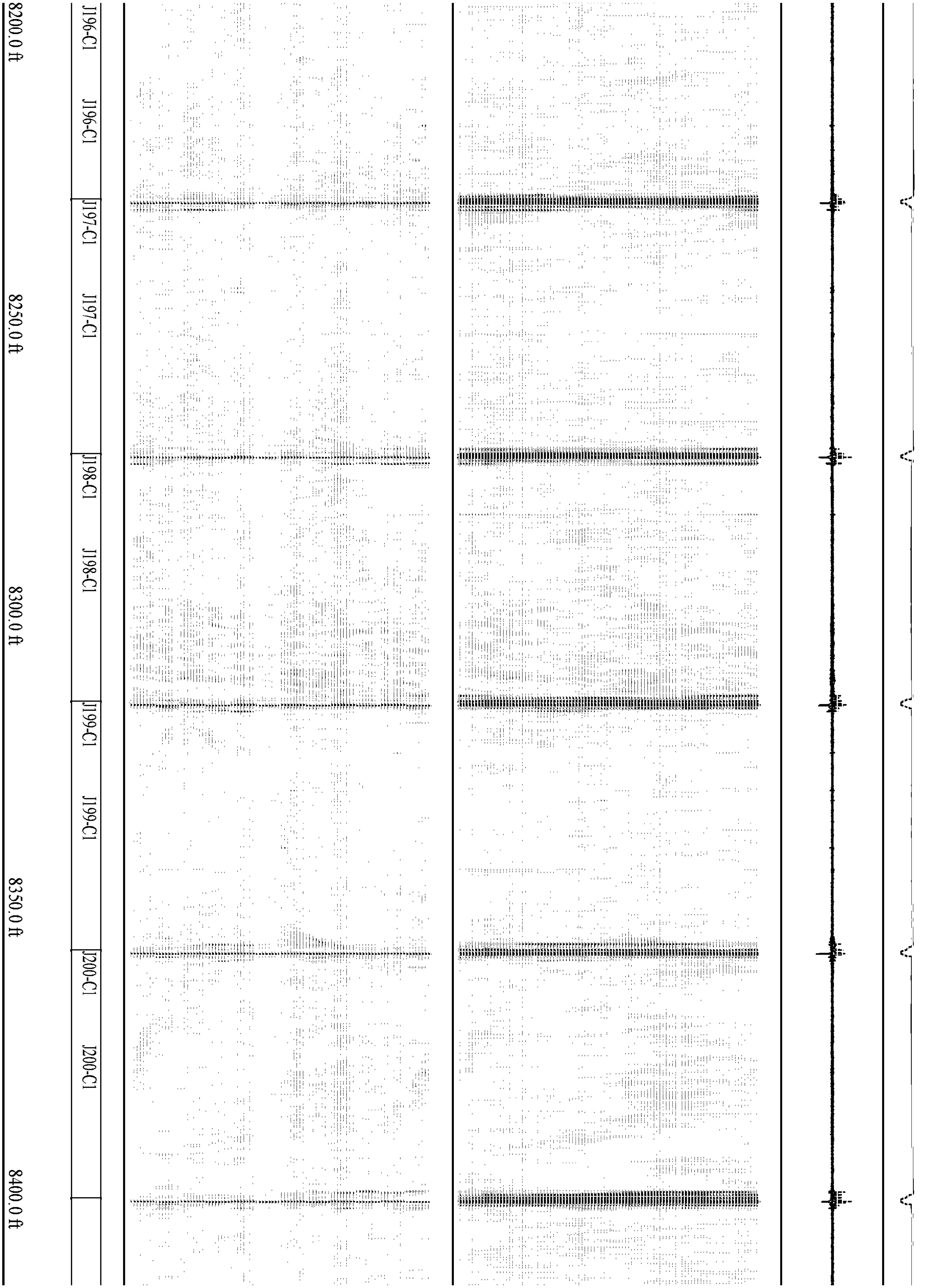

J175-C1
J176-C1
7350.0 ft
J176-C1
J177-C1
7400.0 ft
J177-C1
J178-C1
7450.0 ft
J178-C1
J179-C1
J179-C1
7500.0 ft
J180-C1

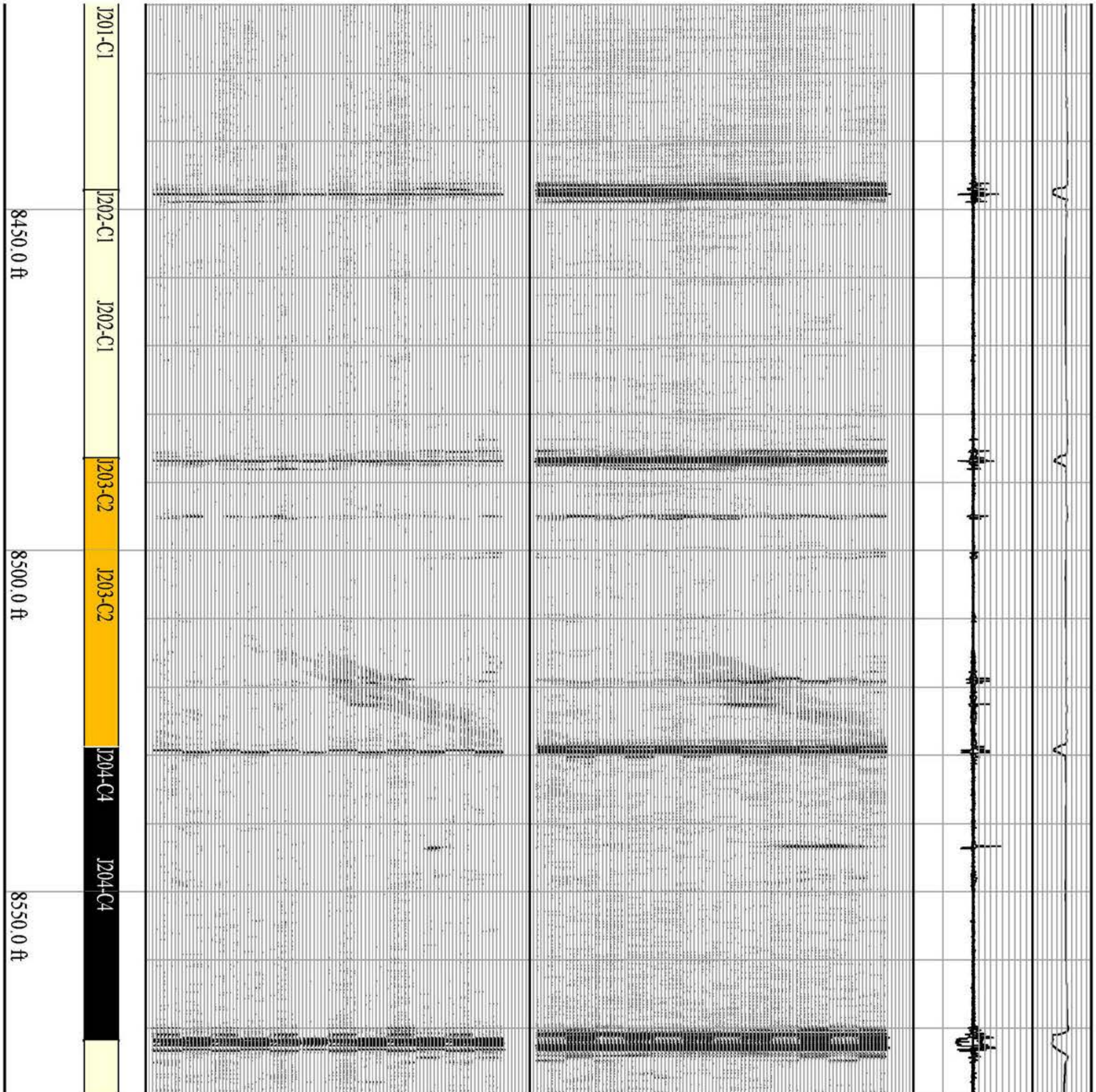

7550.0 ft
J181-C1
J181-C1
7600.0 ft
J182-C1
J182-C1
J183-C1
7650.0 ft
J183-C1
J184-C1
7700.0 ft
J184-C1
J185-C1
J185-C1
7750.0 ft



7800.0 ft
7850.0 ft
7900.0 ft
7950.0 ft
J186-C1
J186-C1
J187-C1
J187-C1
J188-C1
J188-C1
J189-C1
J189-C1
J190-C1
J190-C1


8000.0 ft
8050.0 ft
8100.0 ft
8150.0 ft
J191-C1
J191-C1
J192-C1
J192-C1
J193-C1
J193-C1
J194-C1
J194-C1
J195-C1
J195-C1


8200.0 ft
8250.0 ft
8300.0 ft
8350.0 ft
8400.0 ft
J196-C1
J196-C1
J197-C1
J197-C1
J198-C1
J198-C1
J199-C1
J199-C1
J200-C1
J200-C1



Southern California Gas Company   Standard Sesnon 9

File 20180906_15093B_RSP_0_0_0_0_0.mvl

Joint Summary

Southern California Gas Company
Aliso Canyon
Standard Sesnon 9

Identifier	Start Log Depth	Joint Length	Diameter	Wall Thickness	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	in	lb/ft	%	ft	psi	
JT-1	12.24	26.29	7.000	0.317	23.0	0			1
JT-2	38.53	35.65	7.000	0.317	23.0	0			1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]

JT-3	74.18	41.61	7.000	0.317	23.0	0			1
JT-4	115.79	41.86	7.000	0.317	23.0	0			1
JT-5	157.65	42.15	7.000	0.317	23.0	0			1
JT-6	199.80	41.97	7.000	0.317	23.0	0			1
JT-7	241.77	42.39	7.000	0.317	23.0	0			1
JT-8	284.16	42.03	7.000	0.317	23.0	0			1
JT-9	326.19	42.09	7.000	0.317	23.0	0			1
JT-10	368.28	42.07	7.000	0.317	23.0	0			1
JT-11	410.35	42.67	7.000	0.317	23.0	0			1
JT-12	453.02	41.82	7.000	0.317	23.0	0			1
JT-13	494.83	41.15	7.000	0.317	23.0	0			1
JT-14	535.98	42.17	7.000	0.317	23.0	0			1
JT-15	578.15	41.13	7.000	0.317	23.0	0			1
JT-16	619.29	41.18	7.000	0.317	23.0	0			1
JT-17	660.47	42.33	7.000	0.317	23.0	0			1
JT-18	702.80	41.90	7.000	0.317	23.0	0			1
JT-19	744.70	40.24	7.000	0.317	23.0	16	773.01	5348	1
JT-20	784.93	41.82	7.000	0.317	23.0	0			1
JT-21	826.75	42.25	7.000	0.317	23.0	0			1
JT-22	869.01	42.46	7.000	0.317	23.0	0			1
JT-23	911.47	41.85	7.000	0.317	23.0	0			1
JT-24	953.31	41.89	7.000	0.317	23.0	0			1
JT-25	995.20	42.01	7.000	0.317	23.0	0			1
JT-26	1037.22	41.76	7.000	0.317	23.0	0			1
JT-27	1078.98	42.38	7.000	0.317	23.0	0			1
JT-28	1121.36	36.77	7.000	0.317	23.0	0			1
JT-29	1158.13	42.30	7.000	0.317	23.0	0			1
JT-30	1200.42	43.12	7.000	0.317	23.0	0			1
JT-31	1243.55	41.96	7.000	0.317	23.0	0			1
JT-32	1285.51	40.43	7.000	0.317	23.0	0			1
JT-33	1325.94	42.34	7.000	0.317	23.0	0			1
JT-34	1368.28	42.10	7.000	0.317	23.0	0			1
JT-35	1410.38	41.24	7.000	0.317	23.0	0			1
JT-36	1451.62	41.54	7.000	0.317	23.0	0			1
JT-37	1493.16	42.53	7.000	0.317	23.0	0			1
JT-38	1535.70	42.46	7.000	0.317	23.0	0			1
JT-39	1578.16	41.70	7.000	0.317	23.0	0			1
JT-40	1619.86	42.52	7.000	0.317	23.0	0			1
JT-41	1662.39	41.70	7.000	0.317	23.0	0			1
JT-42	1704.09	37.07	7.000	0.317	23.0	0			1
JT-43	1741.16	40.80	7.000	0.317	23.0	0			1
JT-44	1781.97	40.64	7.000	0.317	23.0	0			1
JT-45	1822.61	42.41	7.000	0.317	23.0	0			1
JT-46	1865.02	40.05	7.000	0.317	23.0	0			1
JT-47	1905.07	40.79	7.000	0.317	23.0	0			1
JT-48	1945.86	41.54	7.000	0.317	23.0	0			1
JT-49	1987.40	41.40	7.000	0.317	23.0	0			1
JT-50	2028.80	41.70	7.000	0.317	23.0	0			1
JT-51	2070.51	42.77	7.000	0.317	23.0	0			1
JT-52	2113.28	41.37	7.000	0.317	23.0	0			1
JT-53	2154.65	42.37	7.000	0.317	23.0	0			1
JT-54	2197.03	42.05	7.000	0.317	23.0	0			1
JT-55	2239.08	36.66	7.000	0.317	23.0	0			1
JT-56	2275.74	41.92	7.000	0.317	23.0	0			1
JT-57	2317.66	40.22	7.000	0.317	23.0	0			1
JT-58	2357.88	41.74	7.000	0.317	23.0	0			1
JT-59	2399.62	43.37	7.000	0.317	23.0	0			1
JT-60	2442.99	42.09	7.000	0.317	23.0	0			1
JT-61	2485.08	40.52	7.000	0.317	23.0	0			1
JT-62	2525.60	41.80	7.000	0.317	23.0	0			1
JT-63	2567.40	39.52	7.000	0.317	23.0	0			1
JT-64	2606.93	42.01	7.000	0.317	23.0	0			1
JT-65	2648.93	42.04	7.000	0.317	23.0	0			1
JT-66	2690.98	42.16	7.000	0.317	23.0	0			1
JT-67	2733.14	40.02	7.000	0.317	23.0	0			1
JT-68	2773.16	41.80	7.000	0.317	23.0	0			1
JT-69	2814.96	41.30	7.000	0.317	23.0	0			1
JT-70	2856.26	43.10	7.000	0.317	23.0	0			1
JT-71	2899.36	37.42	7.000	0.317	23.0	0			1
JT-72	2936.78	41.98	7.000	0.317	23.0	0			1
JT-73	2978.76	41.95	7.000	0.317	23.0	0			1
JT-74	3020.71	42.52	7.000	0.317	23.0	0			1
JT-75	3063.24	42.36	7.000	0.317	23.0	0			1
JT-76	3105.60	41.68	7.000	0.317	23.0	0			1
JT-77	3147.28	41.65	7.000	0.317	23.0	0			1
JT-78	3188.93	38.88	7.000	0.317	23.0	0			1
JT-79	3227.81	41.71	7.000	0.317	23.0	0			1
JT-80	3269.52	41.66	7.000	0.317	23.0	0			1
JT-81	3311.18	41.90	7.000	0.317	23.0	0			1
JT-82	3353.08	41.47	7.000	0.317	23.0	0			1
JT-83	3394.55	42.27	7.000	0.317	23.0	0			1

JT-84	3436.81	42.18	7.000	0.317	23.0	0			1
JT-85	3479.00	41.15	7.000	0.317	23.0	0			1
JT-86	3520.14	42.67	7.000	0.317	23.0	0			1
JT-87	3562.81	35.55	7.000	0.317	23.0	0			1
JT-88	3598.36	42.59	7.000	0.317	23.0	0			1
JT-89	3640.95	42.76	7.000	0.317	23.0	0			1
JT-90	3683.71	42.62	7.000	0.317	23.0	0			1
JT-91	3726.33	41.79	7.000	0.317	23.0	0			1
JT-92	3768.12	42.08	7.000	0.317	23.0	0			1
JT-93	3810.20	42.67	7.000	0.317	23.0	0			1
JT-94	3852.86	42.55	7.000	0.317	23.0	15	3874.13	7890	1
JT-95	3895.41	42.11	7.000	0.317	23.0	0			1
JT-96	3937.52	43.39	7.000	0.317	23.0	0			1
JT-97	3980.90	42.31	7.000	0.317	23.0	0			1
JT-98	4023.22	42.44	7.000	0.317	23.0	0			1
JT-99	4065.65	41.22	7.000	0.317	23.0	0			1
JT-100	4106.87	41.37	7.000	0.317	23.0	0			1
JT-101	4148.24	42.09	7.000	0.317	23.0	0			1
JT-102	4190.33	42.32	7.000	0.317	23.0	0			1
JT-103	4232.66	42.37	7.000	0.317	23.0	0			1
JT-104	4275.03	40.10	7.000	0.317	23.0	0			1
JT-105	4315.13	42.74	7.000	0.317	23.0	0			1
JT-106	4357.87	40.80	7.000	0.317	23.0	0			1
JT-107	4398.67	43.95	7.000	0.317	23.0	0			1
JT-108	4442.62	42.87	7.000	0.317	23.0	0			1
JT-109	4485.49	41.93	7.000	0.317	23.0	0			1
JT-110	4527.42	41.80	7.000	0.317	23.0	15	4530.65	7909	1
JT-111	4569.22	40.82	7.000	0.317	23.0	0			1
JT-112	4610.04	42.87	7.000	0.317	23.0	0			1
JT-113	4652.91	42.53	7.000	0.317	23.0	0			1
JT-114	4695.45	42.64	7.000	0.317	23.0	0			1
JT-115	4738.08	42.34	7.000	0.317	23.0	0			1
JT-116	4780.42	42.38	7.000	0.317	23.0	0			1
JT-117	4822.80	42.33	7.000	0.317	23.0	0			1
JT-118	4865.13	41.80	7.000	0.317	23.0	0			1
JT-119	4906.93	41.64	7.000	0.317	23.0	18	4932.25	7840	1
JT-120	4948.57	42.55	7.000	0.317	23.0	0			1
JT-121	4991.13	41.99	7.000	0.317	23.0	0			1
JT-122	5033.11	42.79	7.000	0.317	23.0	0			1
JT-123	5075.90	42.27	7.000	0.317	23.0	0			1
JT-124	5118.18	42.95	7.000	0.317	23.0	0			1
JT-125	5161.13	42.10	7.000	0.317	23.0	0			1
JT-126	5203.23	41.94	7.000	0.317	23.0	0			1
JT-127	5245.17	42.37	7.000	0.317	23.0	0			1
JT-128	5287.55	39.09	7.000	0.317	23.0	0			1
JT-129	5326.64	42.81	7.000	0.317	23.0	0			1
JT-130	5369.45	42.41	7.000	0.317	23.0	0			1
JT-131	5411.86	43.04	7.000	0.317	23.0	0			1
JT-132	5454.90	41.25	7.000	0.362	26.0	0			1
JT-133	5496.15	41.93	7.000	0.362	26.0	0			1
JT-134	5538.08	43.31	7.000	0.362	26.0	0			1
JT-135	5581.39	42.68	7.000	0.362	26.0	0			1
JT-136	5624.07	43.89	7.000	0.362	26.0	0			1
JT-137	5667.96	42.57	7.000	0.362	26.0	0			1
JT-138	5710.53	43.10	7.000	0.362	26.0	0			1
JT-139	5753.63	42.27	7.000	0.362	26.0	0			1
JT-140	5795.90	43.05	7.000	0.362	26.0	0			1
JT-141	5838.95	41.37	7.000	0.362	26.0	0			1
JT-142	5880.33	43.63	7.000	0.362	26.0	0			1
JT-143	5923.96	43.04	7.000	0.362	26.0	0			1
JT-144	5967.00	43.17	7.000	0.362	26.0	0			1
JT-145	6010.17	43.75	7.000	0.362	26.0	0			1
JT-146	6053.92	41.47	7.000	0.362	26.0	0			1
JT-147	6095.40	43.52	7.000	0.362	26.0	0			1
JT-148	6138.92	42.87	7.000	0.362	26.0	0			1
JT-149	6181.79	41.71	7.000	0.362	26.0	0			1
JT-150	6223.50	43.02	7.000	0.362	26.0	0			1
JT-151	6266.53	43.35	7.000	0.362	26.0	0			1
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JT-162	6742.52	42.00	7.000	0.362	26.0	0			1
JT-163	6784.53	41.54	7.000	0.362	26.0	0			1

JT-164	6826.07	43.23	7.000	0.362	26.0	0			1
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JT-166	6912.74	43.48	7.000	0.362	26.0	0			1
JT-167	6956.22	43.37	7.000	0.362	26.0	0			1
JT-168	6999.59	43.65	7.000	0.362	26.0	0			1
JT-169	7043.24	43.51	7.000	0.362	26.0	0			1
JT-170	7086.75	42.98	7.000	0.408	29.0	0			1
JT-171	7129.73	42.72	7.000	0.408	29.0	0			1
JT-172	7172.46	42.35	7.000	0.408	29.0	0			1
JT-173	7214.81	42.77	7.000	0.408	29.0	0			1
JT-174	7257.58	42.13	7.000	0.408	29.0	0			1
JT-175	7299.71	41.99	7.000	0.408	29.0	16	7315.51	10212	1
JT-176	7341.70	43.43	7.000	0.408	29.0	0			1
JT-177	7385.13	41.95	7.000	0.408	29.0	0			1
JT-178	7427.08	43.77	7.000	0.408	29.0	0			1
JT-179	7470.85	42.60	7.000	0.408	29.0	0			1
JT-180	7513.45	43.44	7.000	0.408	29.0	0			1
JT-181	7556.89	42.82	7.000	0.408	29.0	0			1
JT-182	7599.71	42.66	7.000	0.408	29.0	0			1
JT-183	7642.37	42.76	7.000	0.408	29.0	0			1
JT-184	7685.12	42.67	7.000	0.408	29.0	0			1
JT-185	7727.80	42.73	7.000	0.408	29.0	0			1
JT-186	7770.52	42.75	7.000	0.408	29.0	0			1
JT-187	7813.28	42.17	7.000	0.408	29.0	0			1
JT-188	7855.44	41.97	7.000	0.408	29.0	0			1
JT-189	7897.42	43.39	7.000	0.408	29.0	0			1
JT-190	7940.80	42.17	7.000	0.408	29.0	0			1
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JT-192	8020.03	42.33	7.000	0.408	29.0	0			1
JT-193	8062.36	42.42	7.000	0.408	29.0	0			1
JT-194	8104.78	42.57	7.000	0.408	29.0	0			1
JT-195	8147.35	43.54	7.000	0.408	29.0	0			1
JT-196	8190.89	42.97	7.000	0.408	29.0	0			1
JT-197	8233.86	43.61	7.000	0.408	29.0	0			1
JT-198	8277.47	42.39	7.000	0.408	29.0	0			1
JT-199	8319.86	42.68	7.000	0.408	29.0	0			1
JT-200	8362.54	42.45	7.000	0.408	29.0	0			1
JT-201	8404.99	42.22	7.000	0.408	29.0	0			1
JT-202	8447.21	39.25	7.000	0.408	29.0	0			1
JT-203	8486.46	42.50	7.000	0.408	29.0	23	8522.45	10092	2
JT-204	8528.95	42.89	7.000	0.408	29.0	81	8543.19	0	4
JT-205	8571.84	9.79	7.000	0.408	29.0	0			1

Company: Southern California Gas Company
Well: Standard Sesnon 9
Field: Aliso Canyon
County: Los Angeles State: California

Schlumberger

Ultrasonic Imager
Gamma Ray - CCL
7" 23, 26, 29# casing

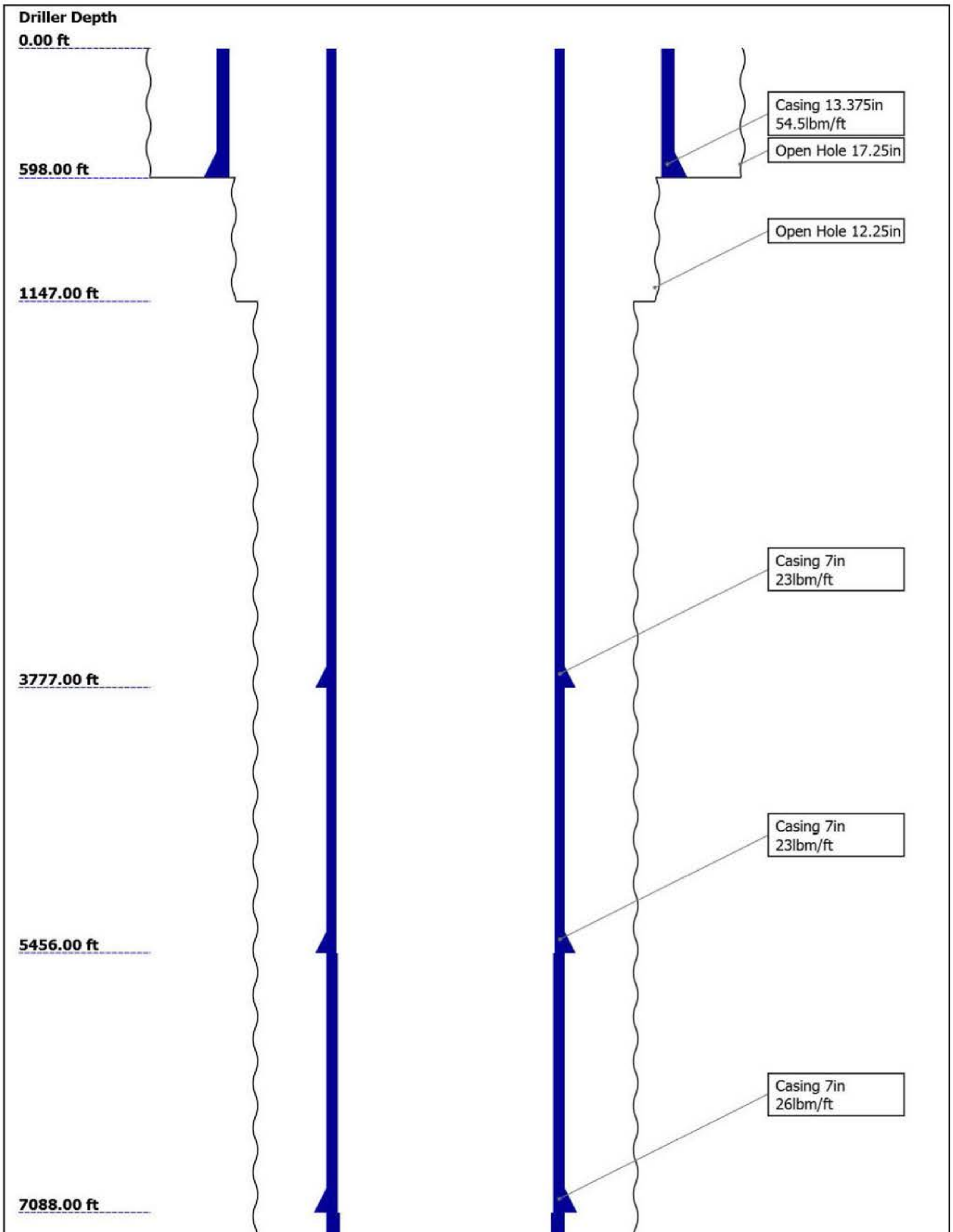
County:	Los Angeles		
Field:	Aliso Canyon		
Location:	1389.74' S & 5254.80' W From Station 84		
Well:	Standard Sesnon 9		
Company:	Southern California Gas Company		
Location:	1389.74' S & 5254.80' W From Station 84	Elev.:	K.B. 2835.71 ft G.L. 2842.63 ft D.F.
Permanent Datum:	Ground Level	Elev.:	2835.71 f
Log Measured From:	Drill Floor	6.92 ft	above Perm.Datum
Drilling Measured From:	Drill Floor		
API Serial No.: 0403700762	Section: 28	Township: 3N	Range: 16W

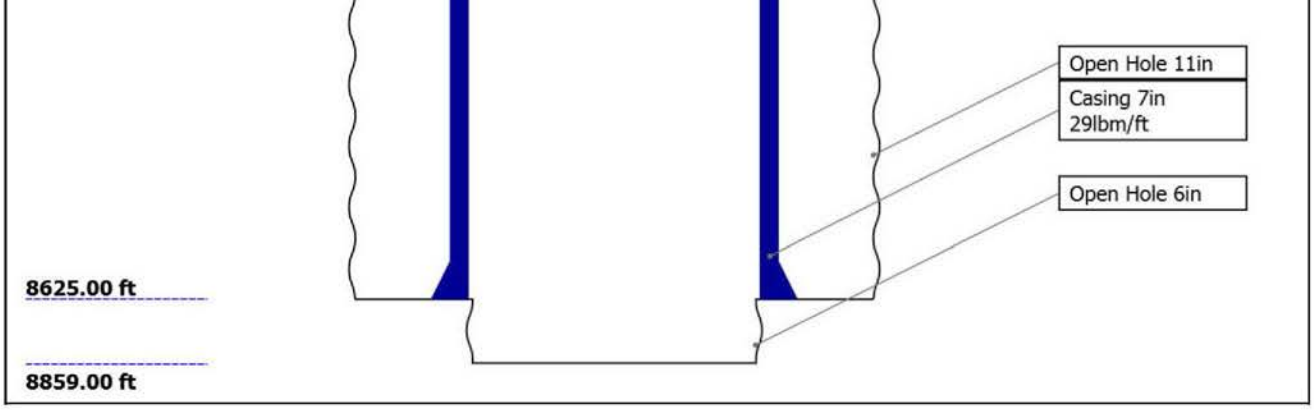
Logging Date	07-Sep-2018	
Run Number	One	
Depth Driller	8599.00 ft	
Schlumberger Depth	8592.00 ft	
Bottom Log Interval	8588.00 ft	
Top Log Interval	14.00 ft	
Casing Fluid Type	Water	
Salinity		
Density	8.5 lbm/gal	
Fluid Level	0.00 ft	
BIT/CASING/TUBING STRING		
Bit Size	6.00 in	
From	8625.00 ft	
To	8859.00 ft	
Casing/Tubing Size	7 in	
Weight	29 lbm/ft	
Grade	N80	
From	7088.00 ft	
To	8625.00 ft	
Max Recorded Temperatures		
Logger on Bottom Time	07-Sep-2018 10:35:00	
Unit Number 3079 Location:	Ventura Ca	
Recorded By	John Lopez	
Witnessed By	Mr Tom MacMahon	

Disclaimer

Contents

Well Sketch


Driller Depth
0.00 ft
598.00 ft
1147.00 ft
3777.00 ft
5456.00 ft
7088.00 ft
Casing 13.375in
54.5lbm/ft
Open Hole 17.25in
Open Hole 12.25in
Casing 7in
23lbm/ft
Casing 7in
23lbm/ft
Casing 7in
26lbm/ft



Borehole Size/Casing/Tubing Record

Bit						
Bit Size (in)	17.25	12.25	11	6		
Top Driller (ft)	0	598	1147	8625		
Top Logger (ft)	0	598	1147	8625		
Bottom Driller (ft)	598	1147	8625	8859		
Bottom Logger (ft)	598	1147	8625	8859		
Casing						
Size (in)	13.375	7	7	7	7	
Weight (lbm/ft)	54.5	23	23	26	29	
Inner Diameter (in)	12.615	6.366	6.366	6.276	6.184	
Grade	J55	J55	N80	N80	N80	
Top Driller (ft)	0	0	3777	5456	7088	
Top Logger (ft)	0	0	3777	5456	7088	
Bottom Driller (ft)	598	3777	5456	7088	8625	
Bottom Logger (ft)	598	3777	5456	7088	8625	

Remarks and Equipment Summary

One: Toolstring

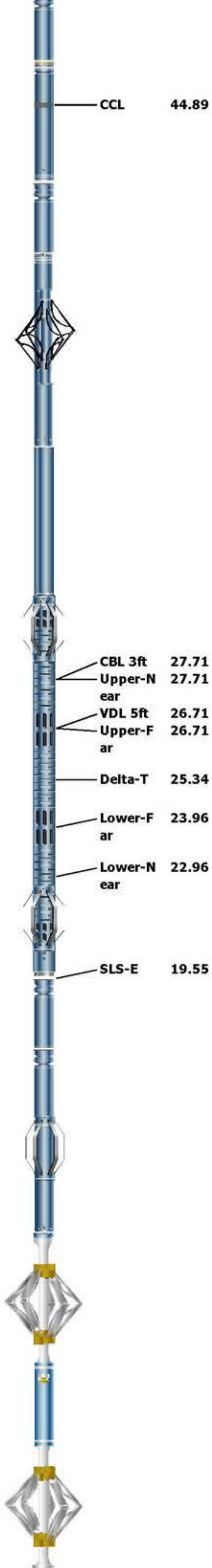
Equip name	Length
LEH-QT:2867 LEH-QT:2867	63.58
DTC-H ECH-KC DTC-H	60.09
HGNS-H:4177 HGNH:4819 NPV-N NSR-F:1303 HMCA-H HGNS-H:4177 HACCZ-H:4177	57.09
AH-184	47.68

MP name	Offset
Red	
CTEM	59.19
HV	0.00
TelStatus	57.09
ToolStatus	57.09
Temperature	57.07
GR	56.35
CNL Porosity	50.02
HGNS	47.68
HMCA	47.68
Accelerometer	0.00

One: Remarks

One: Remarks
Rig: Ensign 343
Toolstring ran as per toolsketch.
Two centralizers on USIS and two CME-Y used to centralize ultrasonic tool.
Correlated to Schlumberger resistivity Log dated 1-17-47
No pressure run on repeat pass, 1000 PSI pressure run on main pass
USIT run for cement and corrosion
USIT run at 10 deg 1.5 inch standard res 2800 FPH, Anomolies repeated at 10 Deg 0.6 inch res at 1200 FPH
CNL run eccentered
Crew: Coupart, Allen
Thank You For Choosing Schlumberger
5 inch Liner top at 8599 ft, logged from Liner top to surface
Anomolies noted at 2560 to 2570 ft and from 1628 to 1630 ft, appear to be caused by tool eccentering. Repeated in Hi-Res

AH-184[4]	47.68	
CAL-YA CAL-YA	45.68	
AH-184[3]:2985	42.18	
DSLT-H:8 236 ECH-KH:8 678 DSLC-H:82 36 SLS-E:120 6	40.18	
AH-184[2]:2882	19.54	
AH-184[1]:6735	17.54	
USIT-E:17 64 ECH-MFA: 1764 USAC-A:1 764 USIS-A:27 20 USSC-B USRS-B USI-SENS OR:3349 USI-TX	15.54	



Speed correction applied to Logs

Lengths are in ft
Maximum Outer Diameter = 6.500 in
Line: Sensor Location, Value: Gating Offset
All measurements are relative to TOOL_ZERO

Job Event Summary

Event	Time	Duration	Interval	Remark
Log[2]:Down	Sep-07-2018 08:08	01:15:54	436.1 - 8598.16 ft	FPM
Log[5]:Up	Sep-07-2018 09:40	00:07:43	8593.13 - 8282.49 ft	Repeat No pressure
Log[6]:Up	Sep-07-2018 09:51	04:01:06	8592.71 - 93.36 ft	Main 1000 Psi Pressure applied
Log[7]:Up	Sep-07-2018 14:11	00:11:18	2659.49 - 2491.49 ft	Hi-Res 1
Log[8]:Up	Sep-07-2018 14:26	00:14:03	1758.38 - 1551.52 ft	Hi Res 2
Log[9]:Up	Sep-07-2018 14:46	00:13:24	318.32 - 11.43 ft	Surface data

USIT - Fluid Properties Measurement

Run Name	Pass Name	Start Depth(ft)	Stop Depth(ft)
Run 1	Log[2]:Down	436.1	8598.16

Fluid Velocity = "Automatic".
CFVL equals DFSL channel

Start Depth(ft)	Stop Depth(ft)	Start Value(us/ft)	End Value(us/ft)

Mud Impedance = "Theoretical".
CZMD uses theoretical results.
MUD_N_THE=1.00
DFD=1.02g/cm3(8.50lbm/gal)

Start Depth(ft)	Stop Depth(ft)	Start Value(Mrayl)	End Value(Mrayl)

Composite 1

Main Pass 5 in = 100 ft

Software Version

Acquisition System	Version
Maxwell 2018 SP1	8.1.99839.3100
Application Patch	Wireline_Hotfix-Mandatory-2018SP1_8.1.102865

Computation	Description	Version
CEVAL	Sonic Cement Evaluation Computation Ensemble provides common Parameters and Channels	8.1.99839.3100
Cementation	Cementation Computation Application	8.1.99839.3100

Tool Elements	Description	Software Version	Firmware Version
HGNS-H	HILT Gamma-Ray and Neutron Sonde, 150 degC	8.1.99839.3100	2.0
SLS-E	Sonic Logging Sonde E supports 3'-5'BHC DT and CBL/VDL	8.1.99839.3100	4.0
USI-SENSOR	USIT Transducer Element	1.2.111	DSP: v2.99

Composite Summary

Run Name	Pass Objective	Direction	Top	Bottom	Start	Stop	DSC Mode	Depth Shift	Include Parallel Data
One	Log[6]:Up	Up	93.36 ft	8592.71 ft	07-Sep-2018 9:51:23 AM	07-Sep-2018 1:52:30 PM	ON	8.00 ft	No
One	Log[9]:Up	Up	11.43 ft	318.32 ft	07-Sep-2018 2:46:40 PM	07-Sep-2018 3:00:05 PM	ON	9.00 ft	No

All depths are referenced to toolstring zero

Log

Company:Southern California Gas Company Well:Standard Sesnon 9

Composite 1:S003

Description: USI VDL Cement Format: Log (LBV1_USI-VDL (DSLT) Cement 7inch) Index Scale: 5 in per 100 ft Index Unit: ft Index Type: Measured Depth Creation Date: 07-Sep-2018 22:55:36

TIME_1900 - Time Marked every 60.00 (s)

ERAV_IRAV
ERAV_RHF1
IRAV_LHF1
IRAV_ERAV
LHF1_ERAV
RHF1_IRAV

Median of Unflagged External Radii (ERAV_RF) USIT-E[1]
3.7 in 2.7

Median of Unflagged External Radii (ERAV_RF) USIT-E[1]
2.7 in 3.7

Casing Collar Locator Ultrasonic (CCLU) USIT-E[1]
-30 in 10

Amplitude of Eccentering for Unflagged Waves (ECCE_RF) USIT-E[1]
0 in 0.5

Gamma Ray (ECGR) HGNS[1]
0 gAPI 200

Median Internal Radius of Casing Corrected for Eccentering (IRAV_RF) USIT-E[1]
3.7 in 2.7

Minimum of Unflagged Internal Radii (IRMN_RF) USIT-E[1]
3.7 in 2.7

Maximum of Unflagged Internal Radii (IRMX_RF) USIT-E[1]
3.7 in 2.7

Minimum of Unflagged Internal Radii (IRMN_RF) USIT-E[1]
2.7 in 3.7

Maximum of Unflagged Internal Radii (IRMX_RF) USIT-E[1]
2.7 in 3.7

Median Internal Radius of Casing Corrected for Eccentering (IRAV_RF) USIT-E[1]
2.7 in 3.7

U L B R U
Orientation: Top of Hole
Absent 1.000 2.500 4.000 5.500 7.000
Custom Normalization
USIT - Acoustic Impedance (AIBK) USIT-E[1]
(Mrayl)

Acoustic Impedance Minimum (AIMN) USIT-E[1]
-1 Mrayl 9

Acoustic Impedance Average (AIAV) USIT-E[1]
-1 Mrayl 9

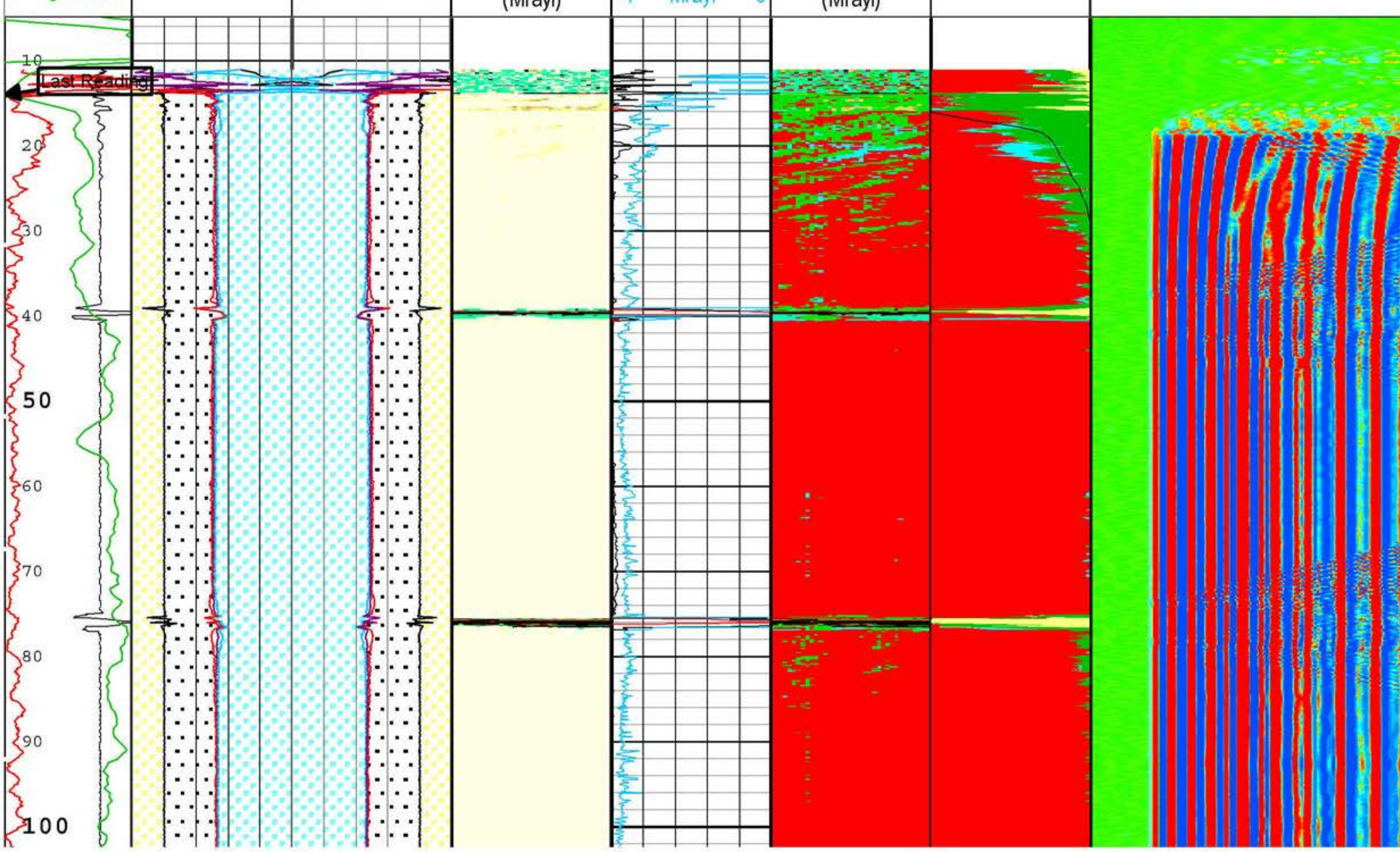
Acoustic Impedance Maximum (AIMX) USIT-E[1]
-1 Mrayl 9

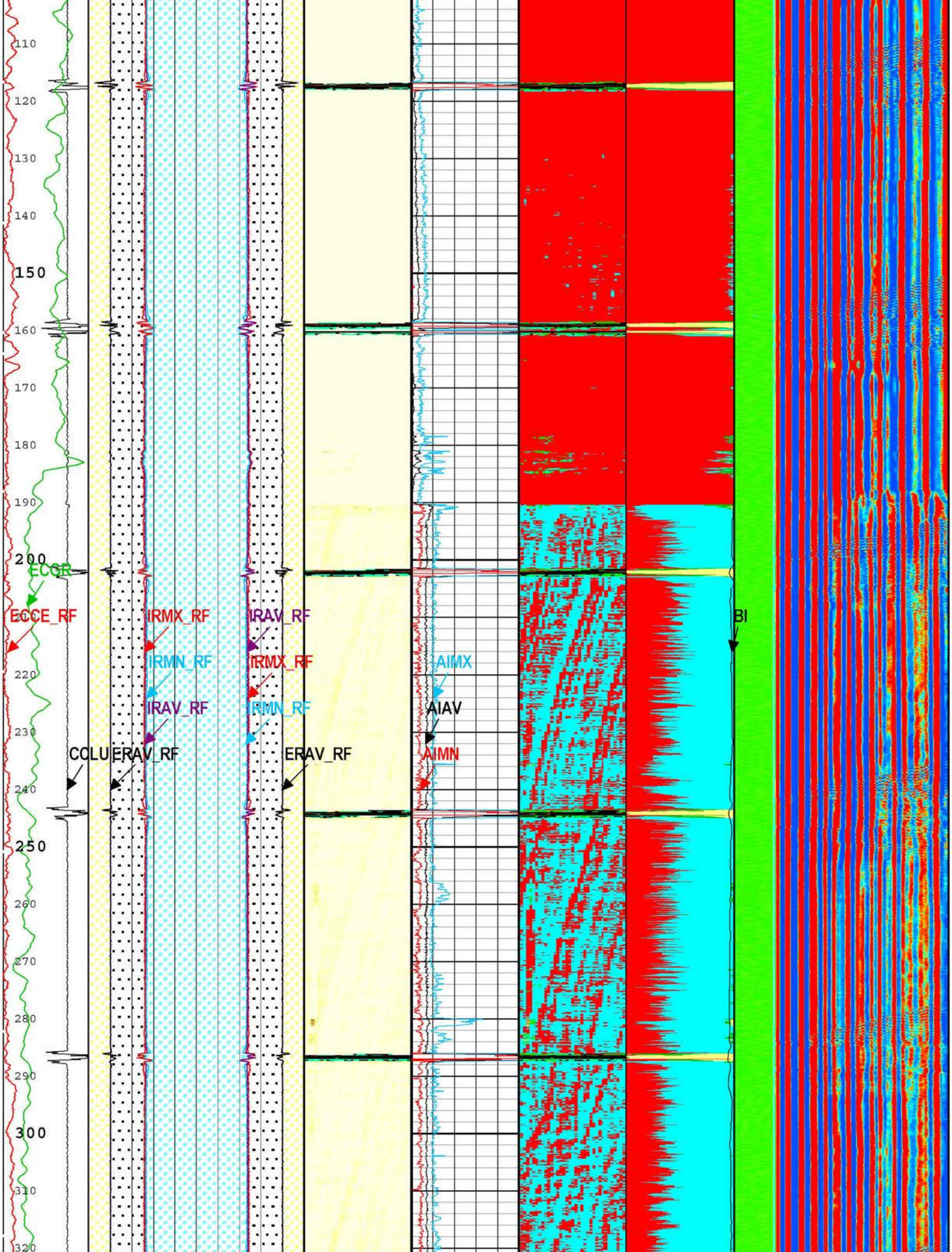
U L B R U
Orientation: Top of Hole
Absent 0.300 3.581 5.054 6.527 8.000
Custom Normalization
USIT - Acoustic Impedance With Micro-debonding Image (AI_MDEBOND_IMG) USIT-E[1]
(Mrayl)

Bonded
Gas
Liquid
Micro-debonding

Bond Index (BI) DSLT-H[1]
1 0

Min Amplitude Max
Sonic VDL Curve DSLT-H[1]
200 us 1200

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IRMX_RF
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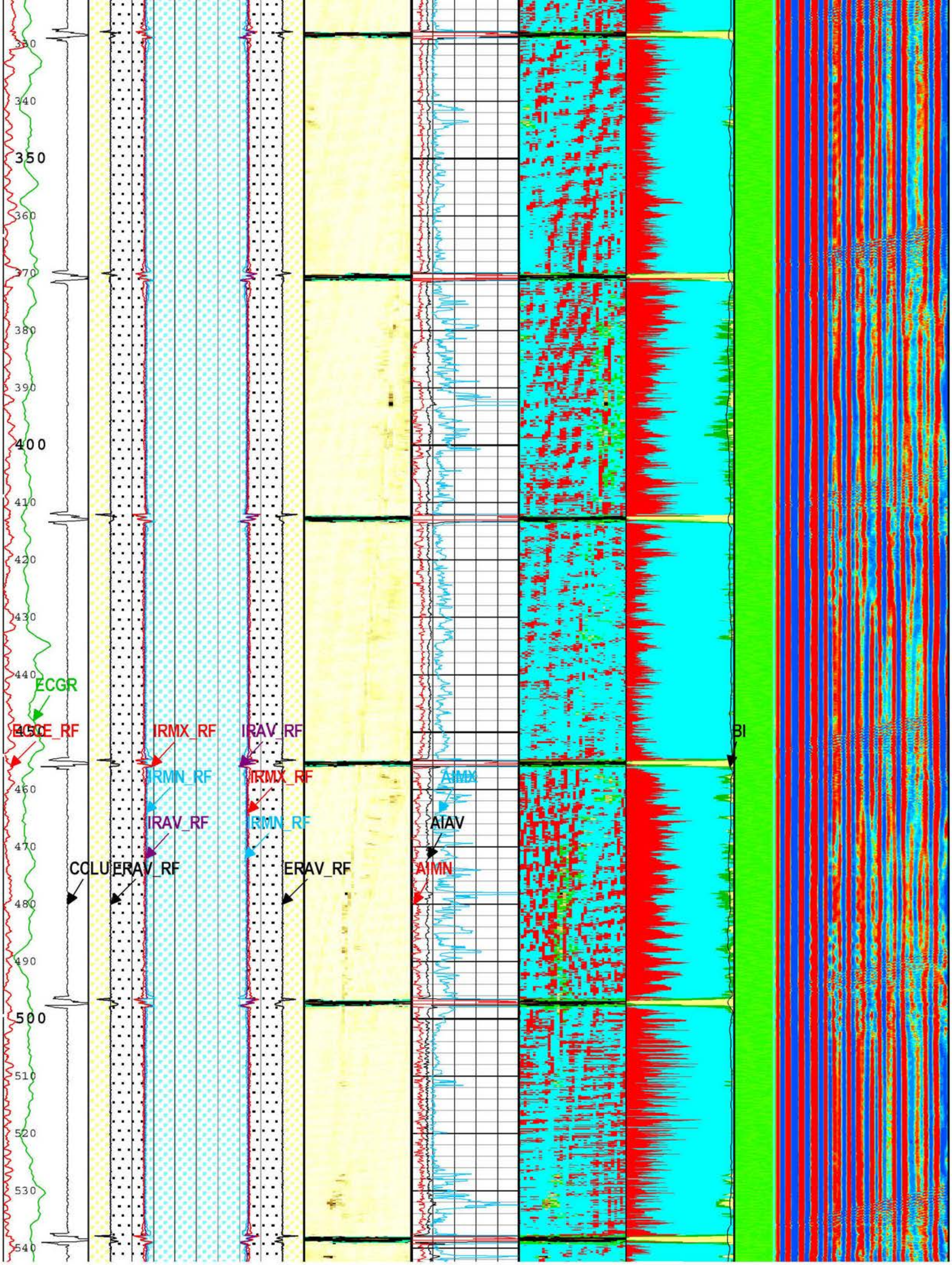

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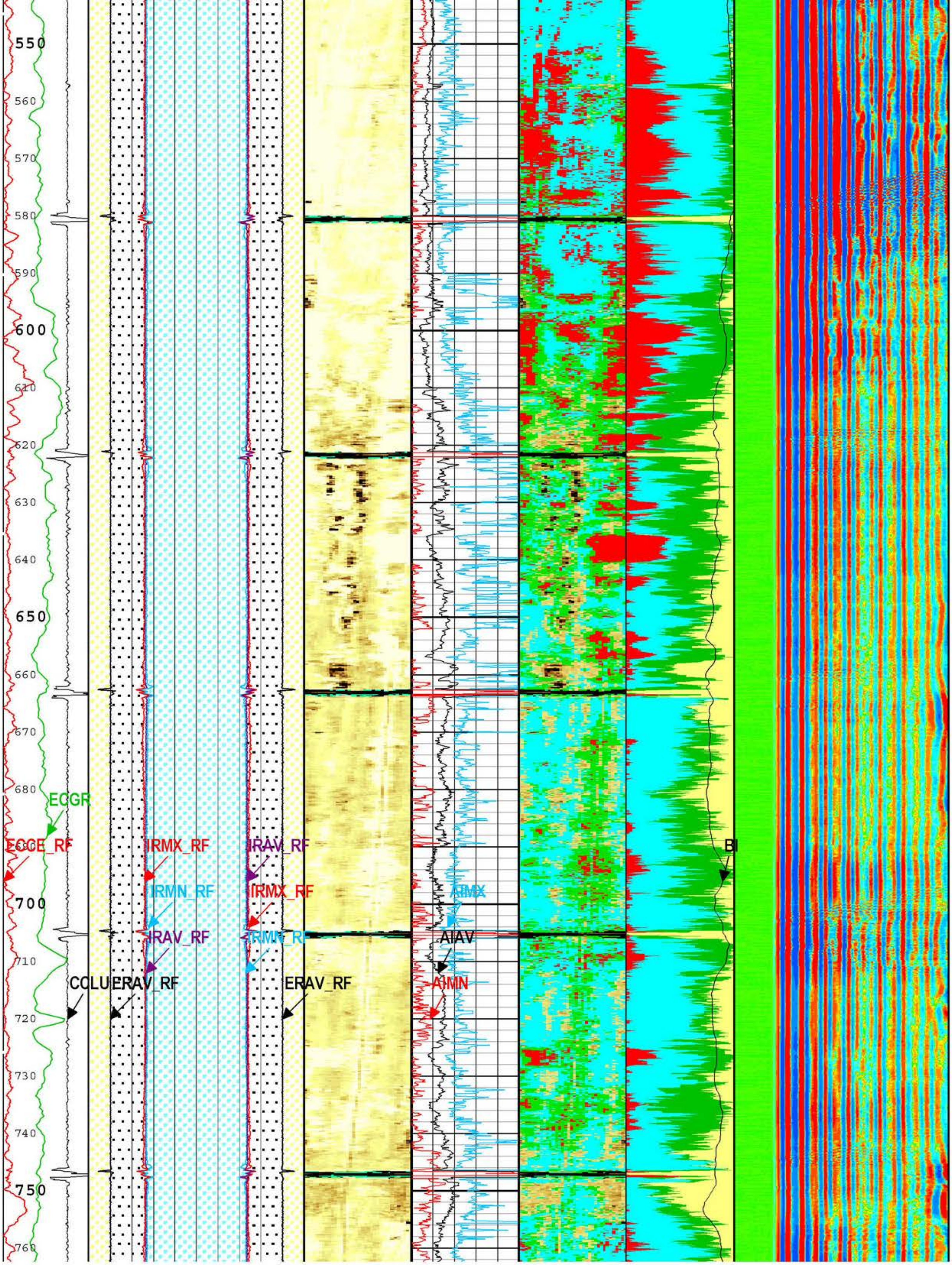
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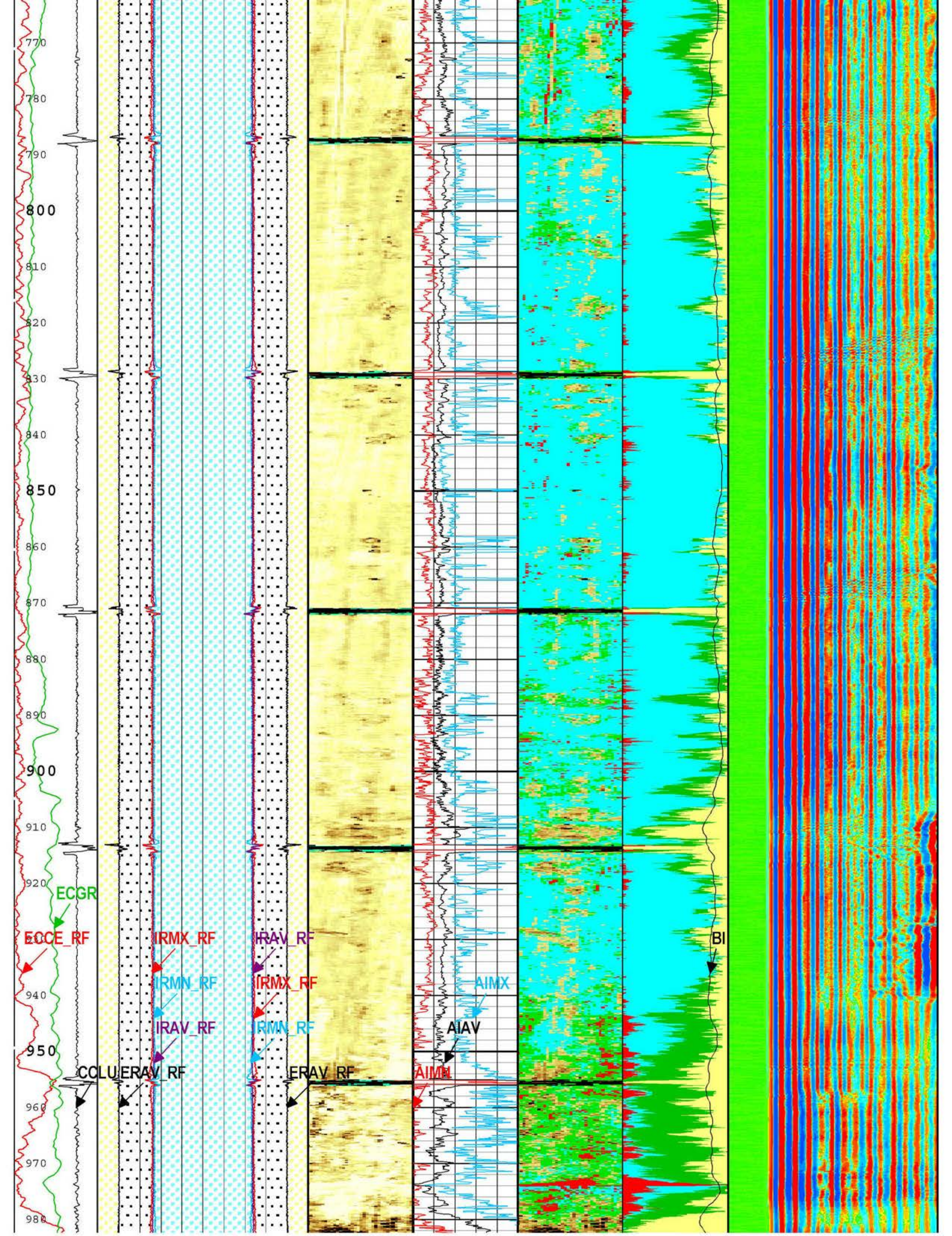
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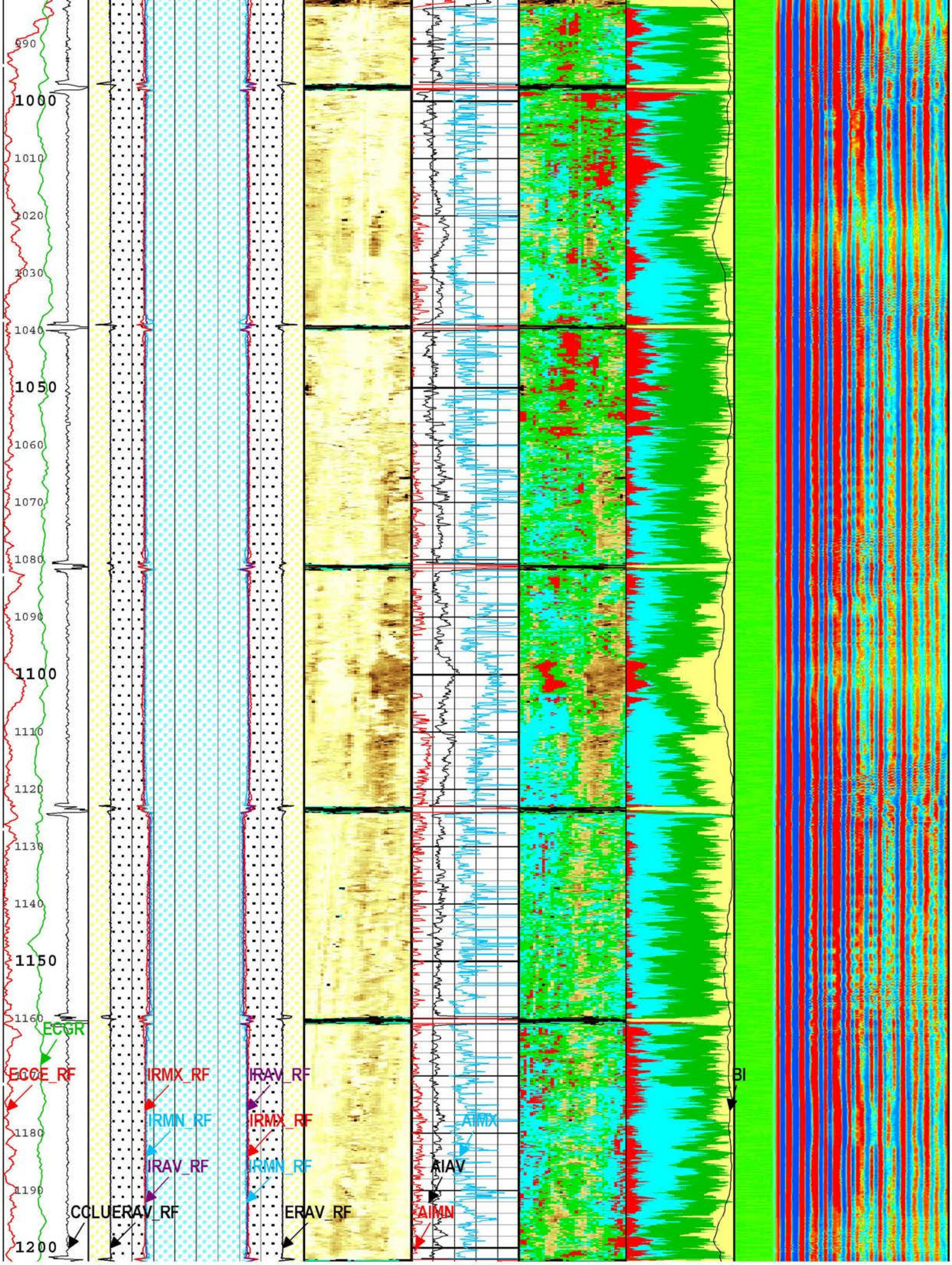

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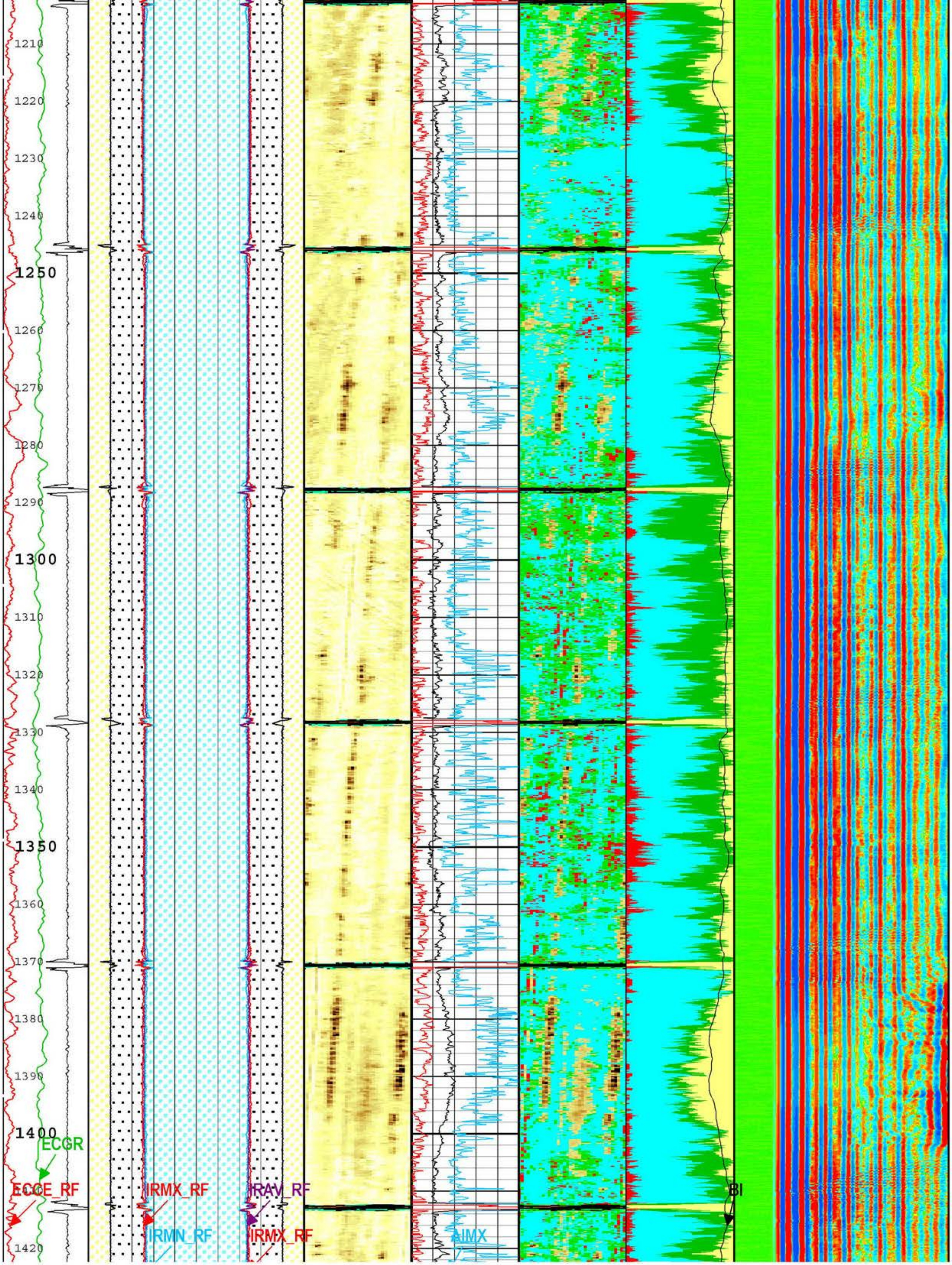
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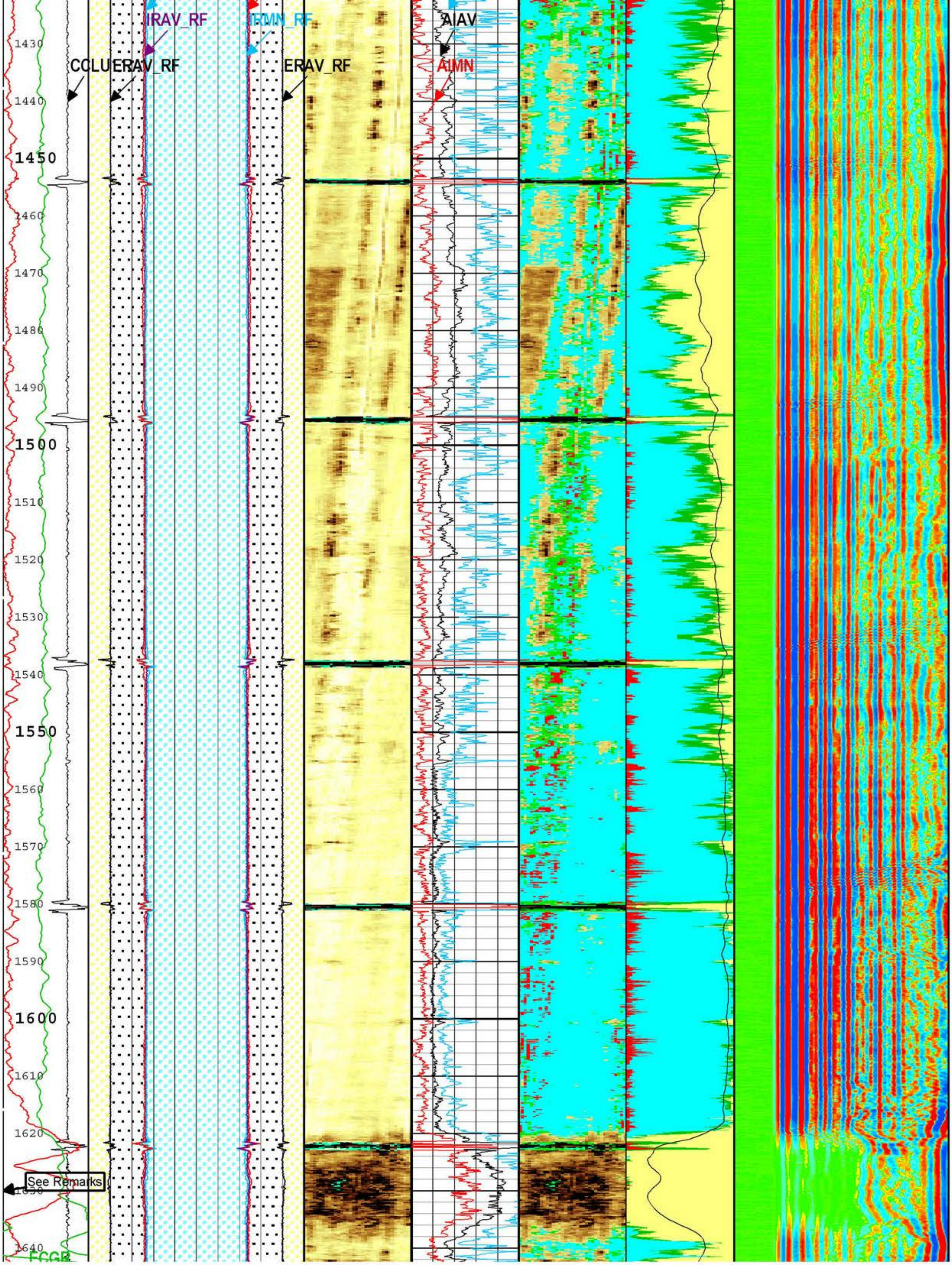

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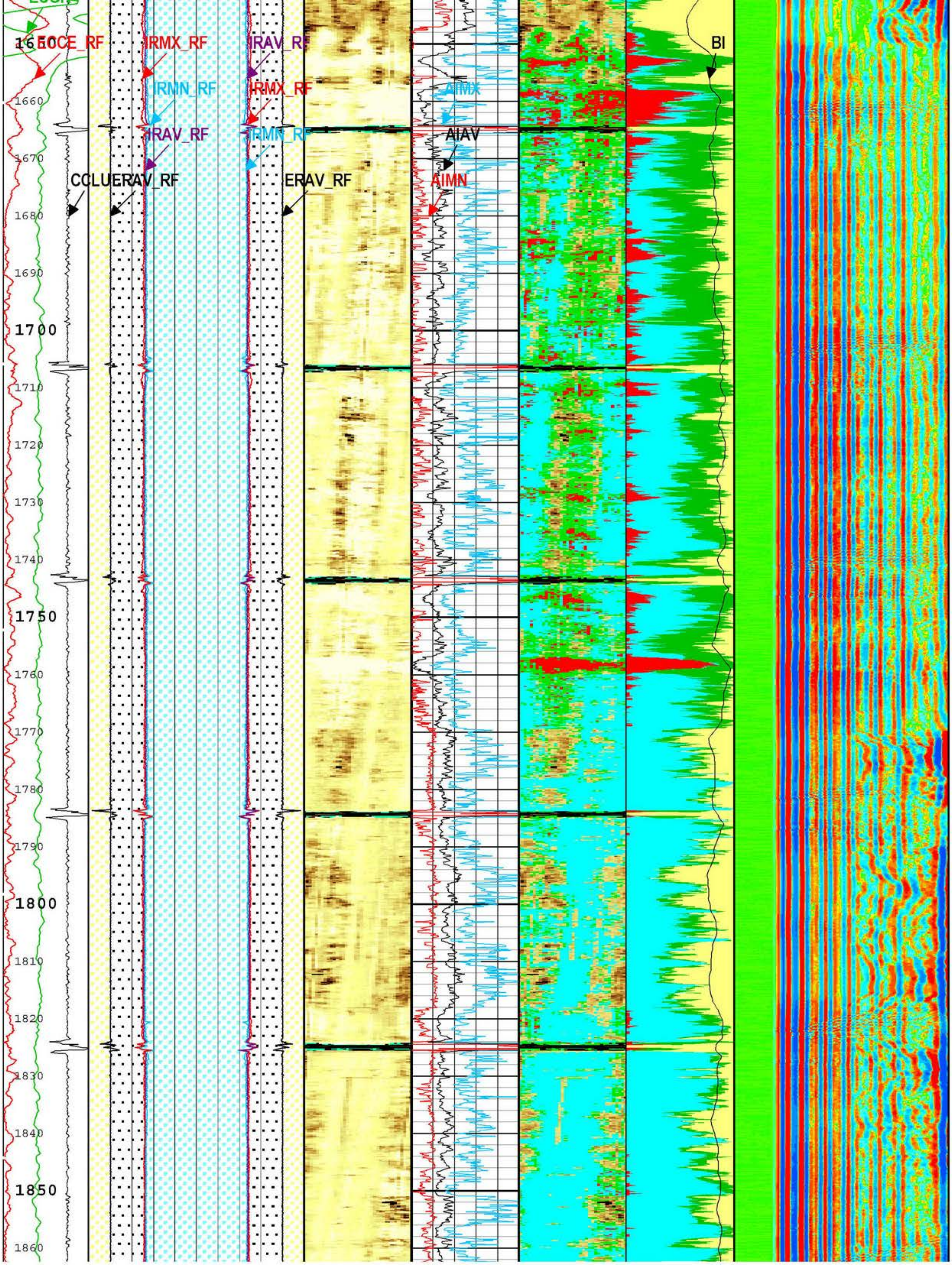
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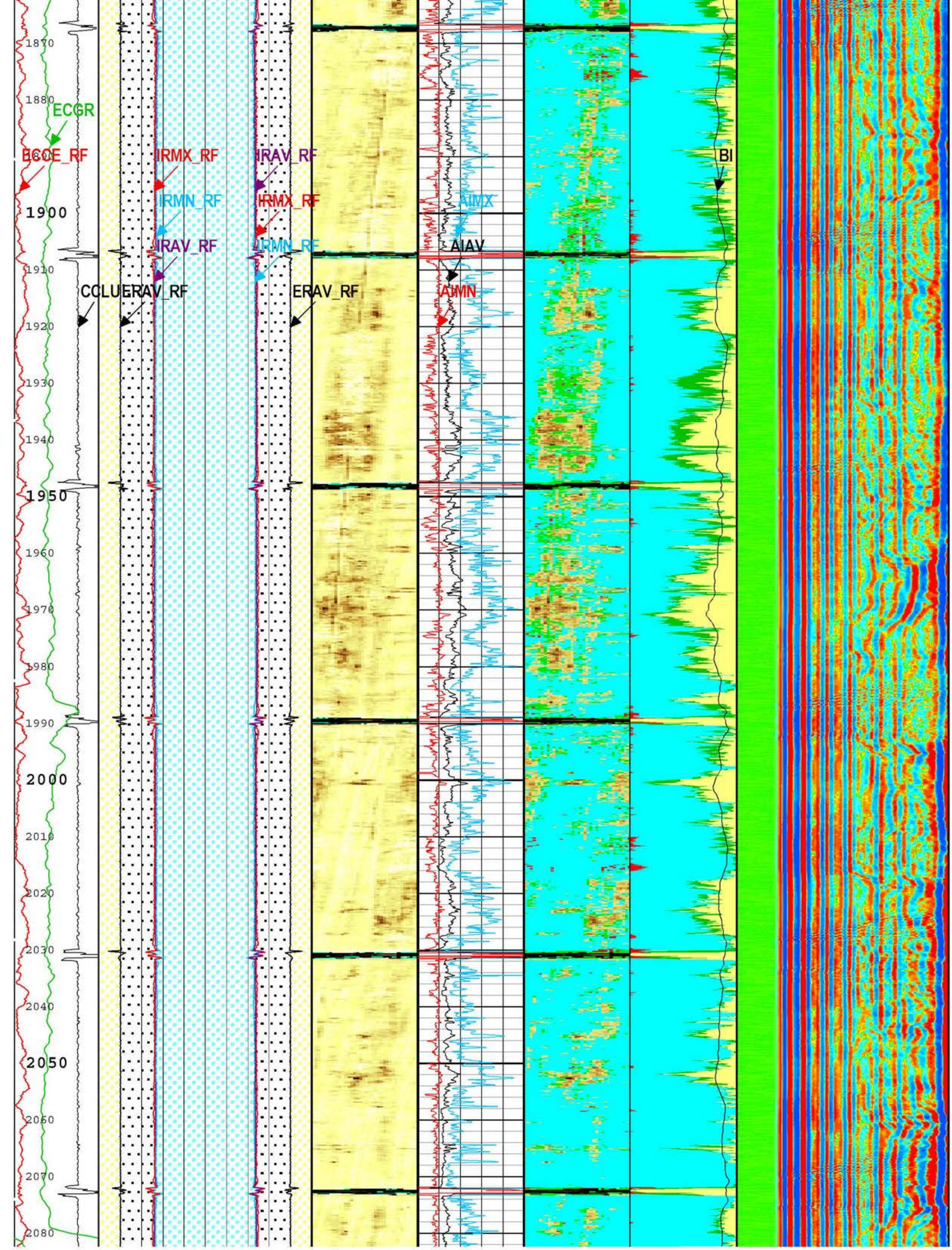
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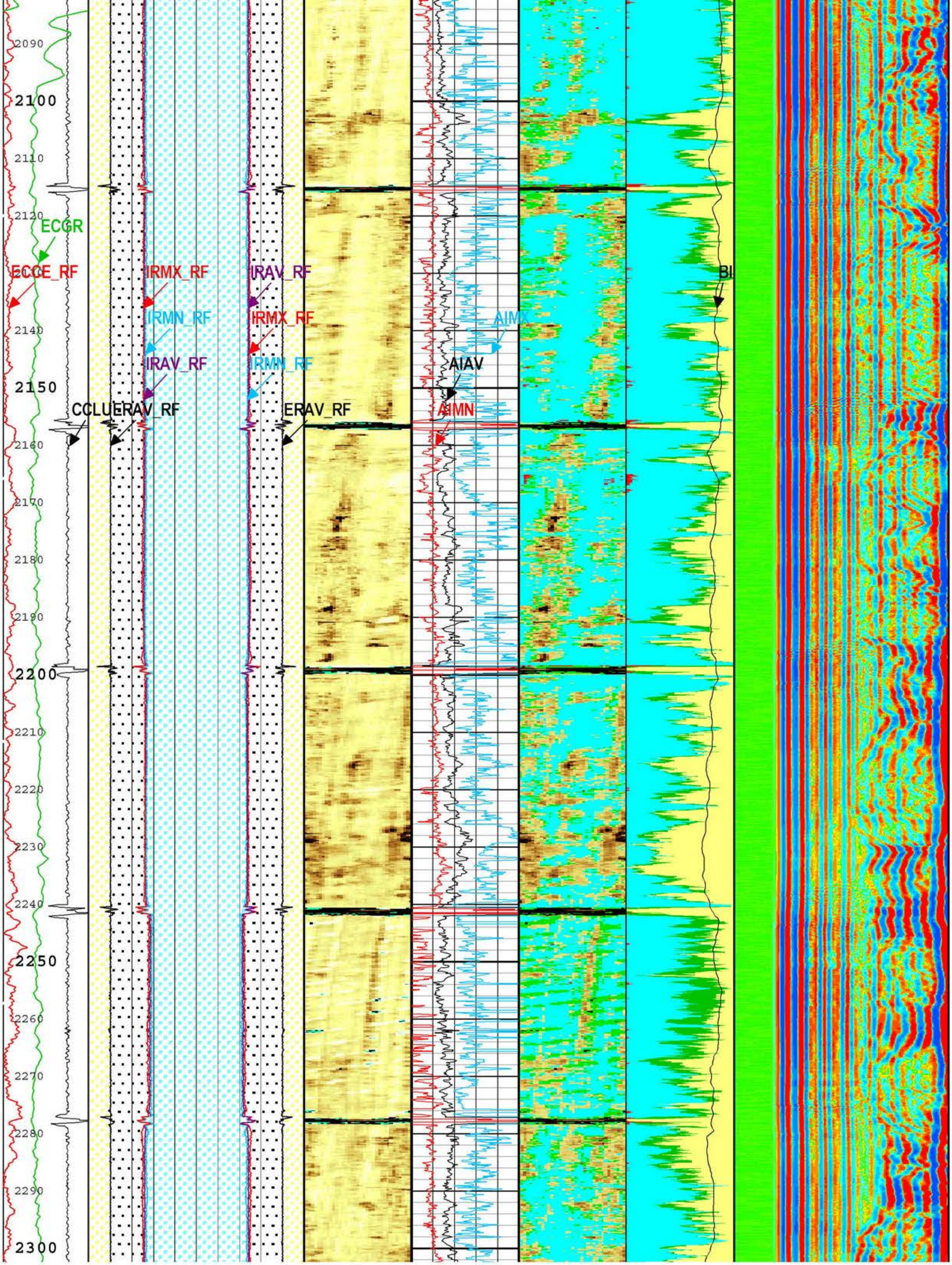
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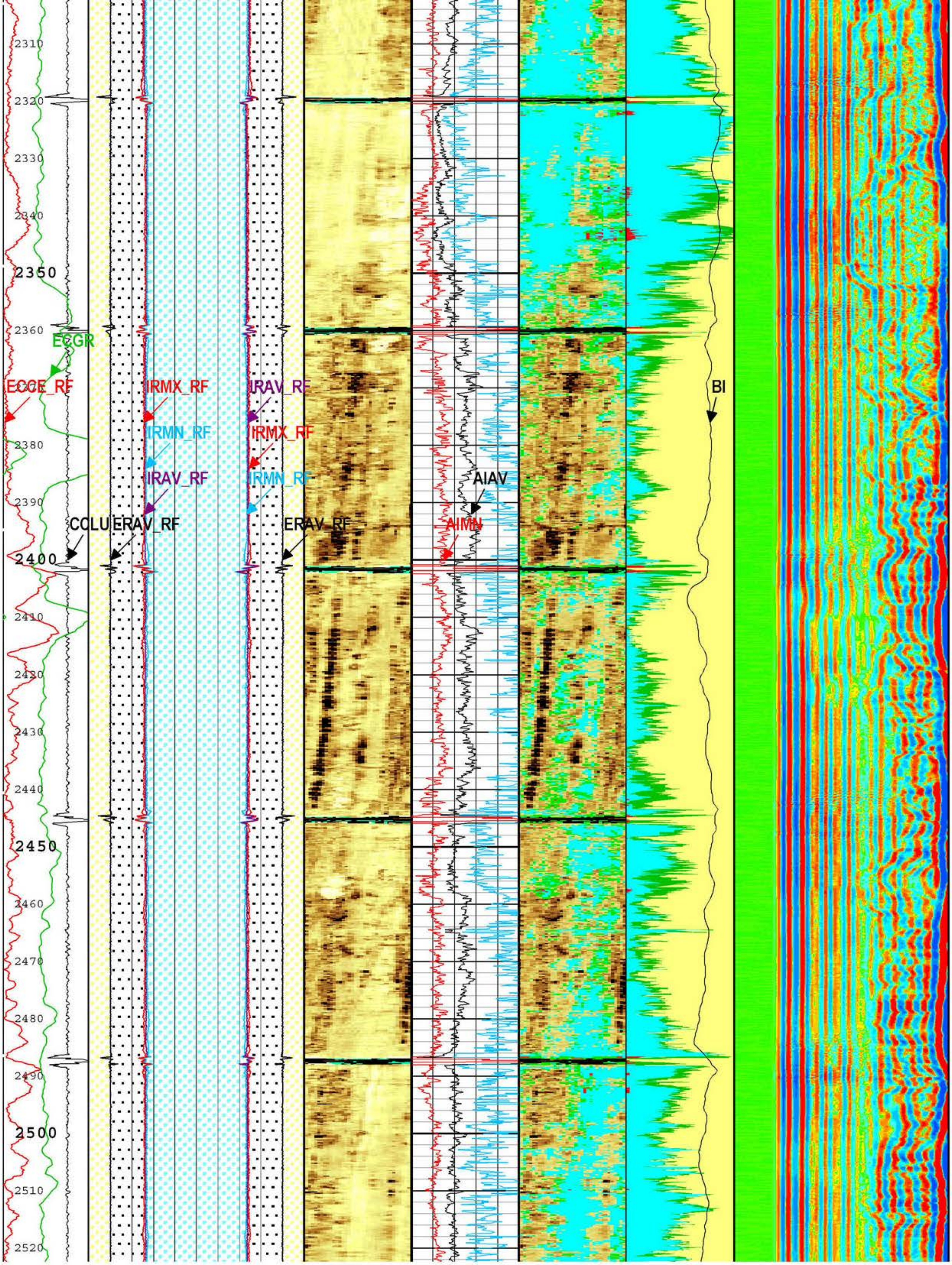
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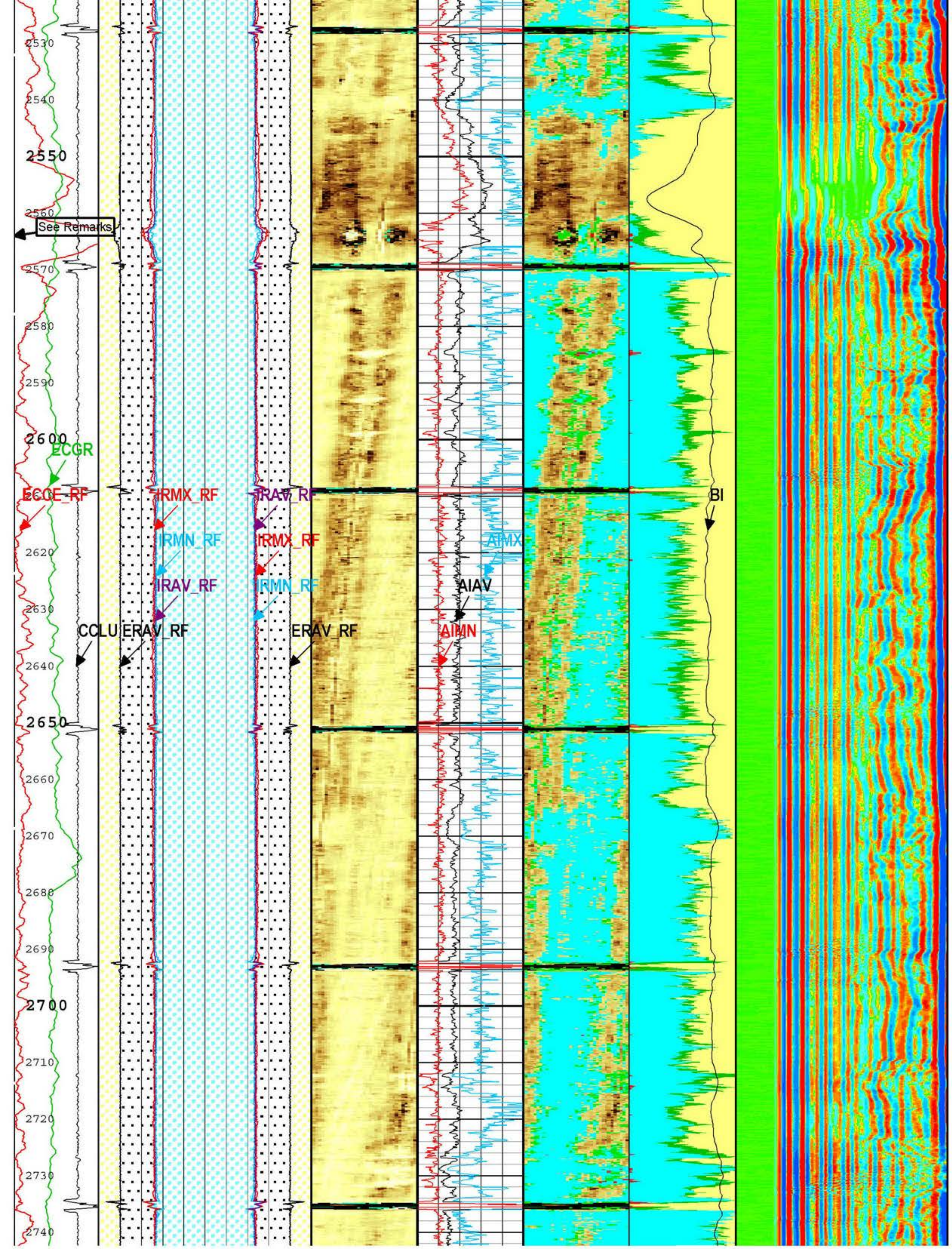
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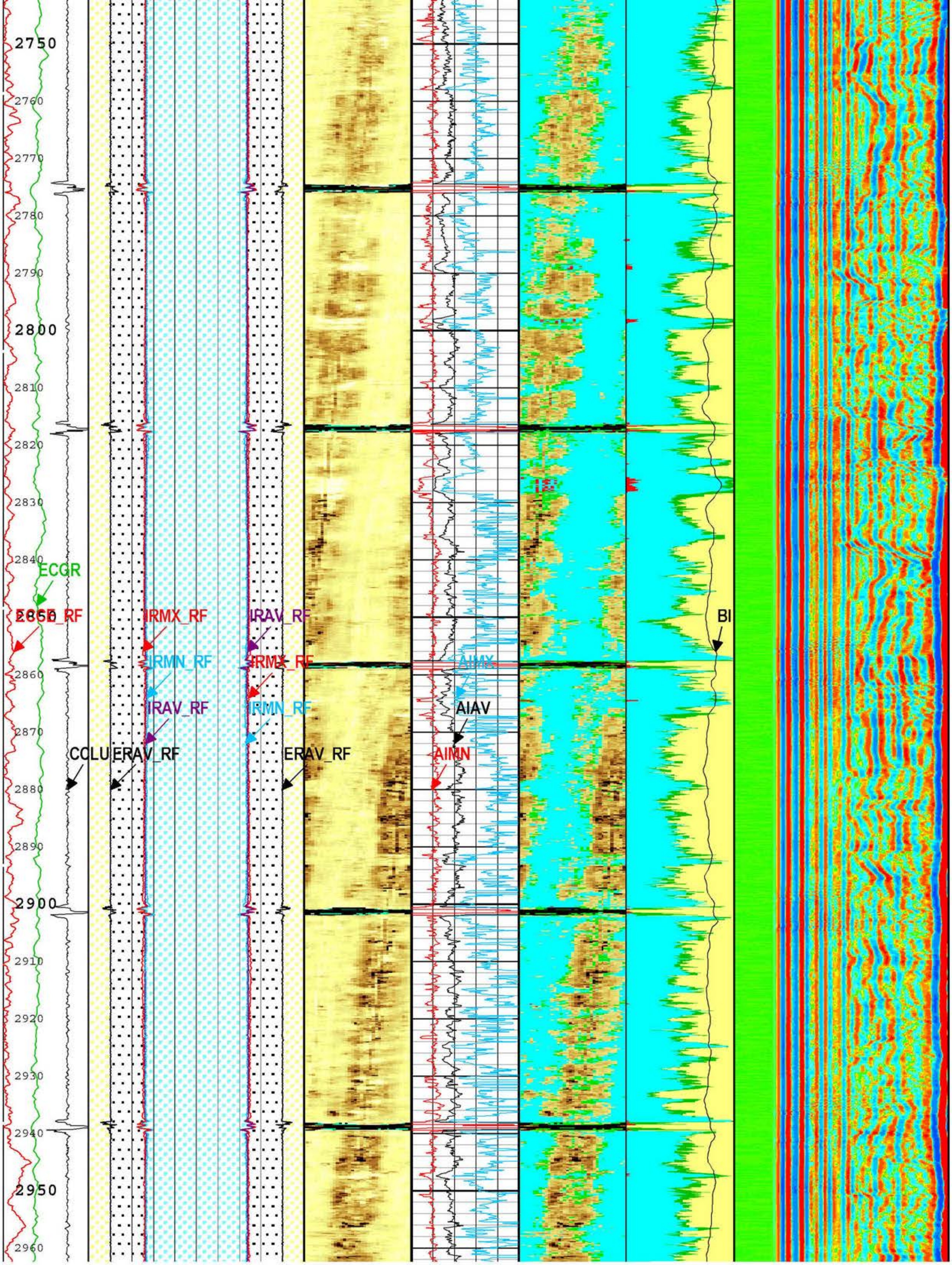
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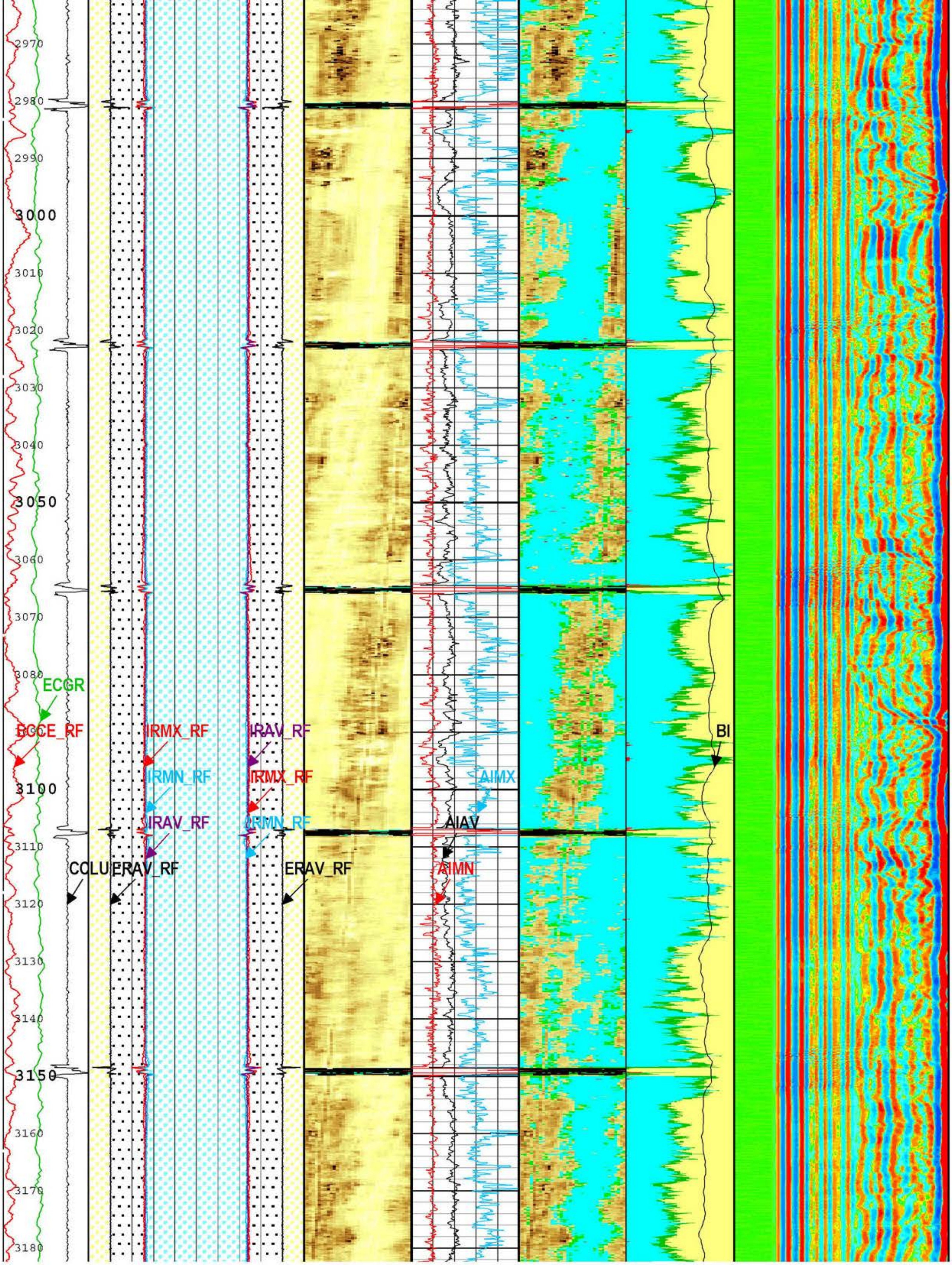

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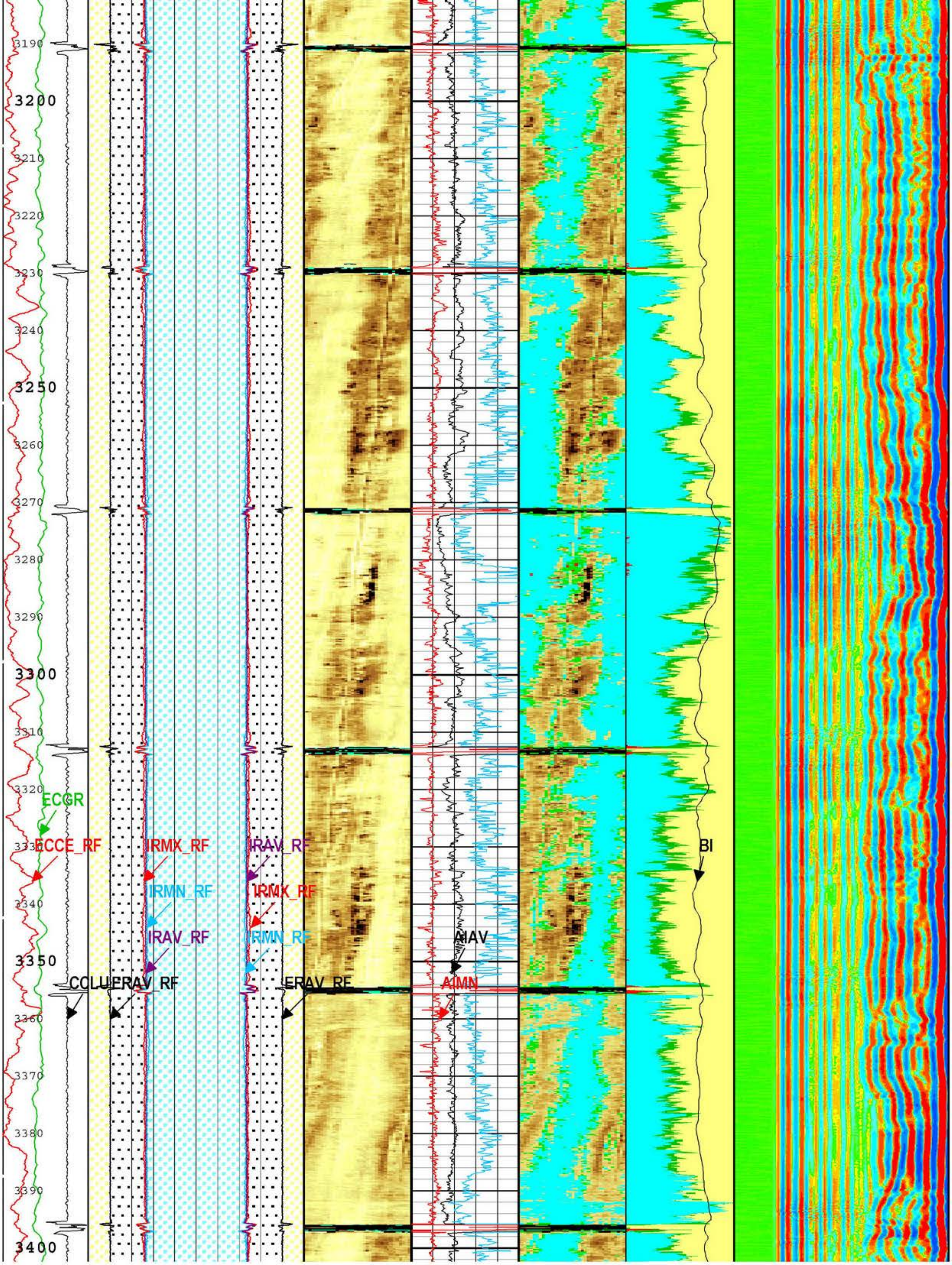
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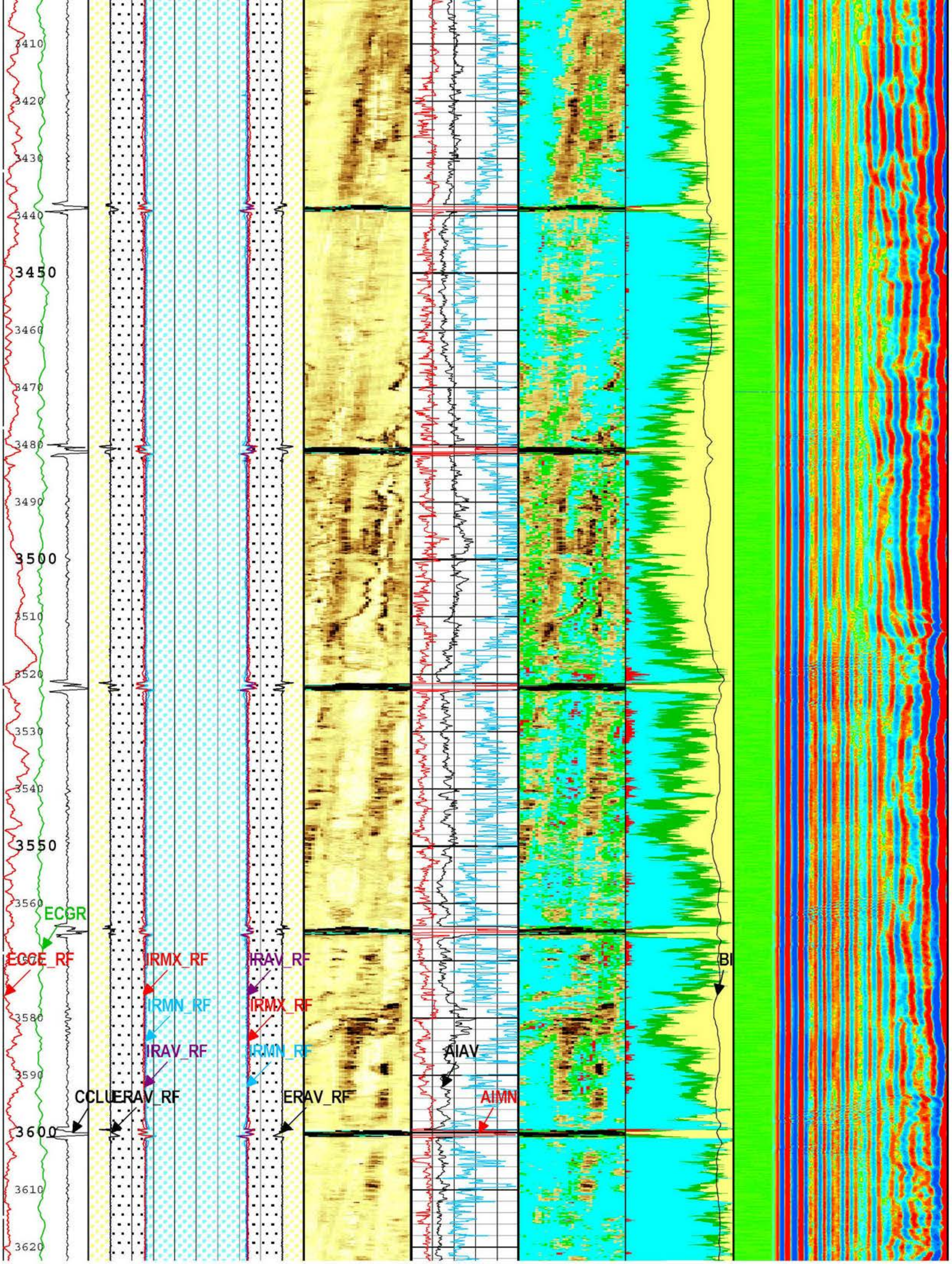
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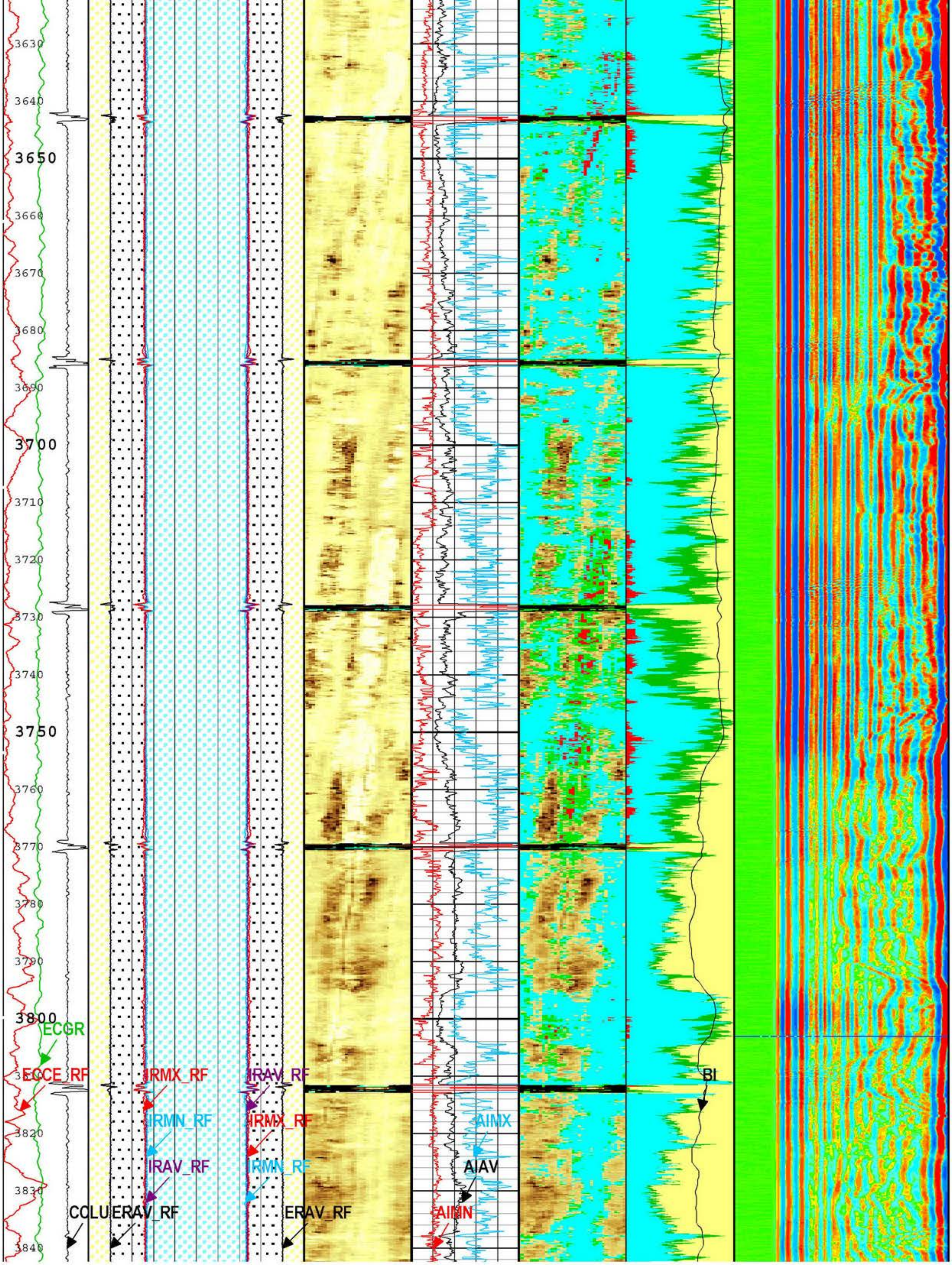
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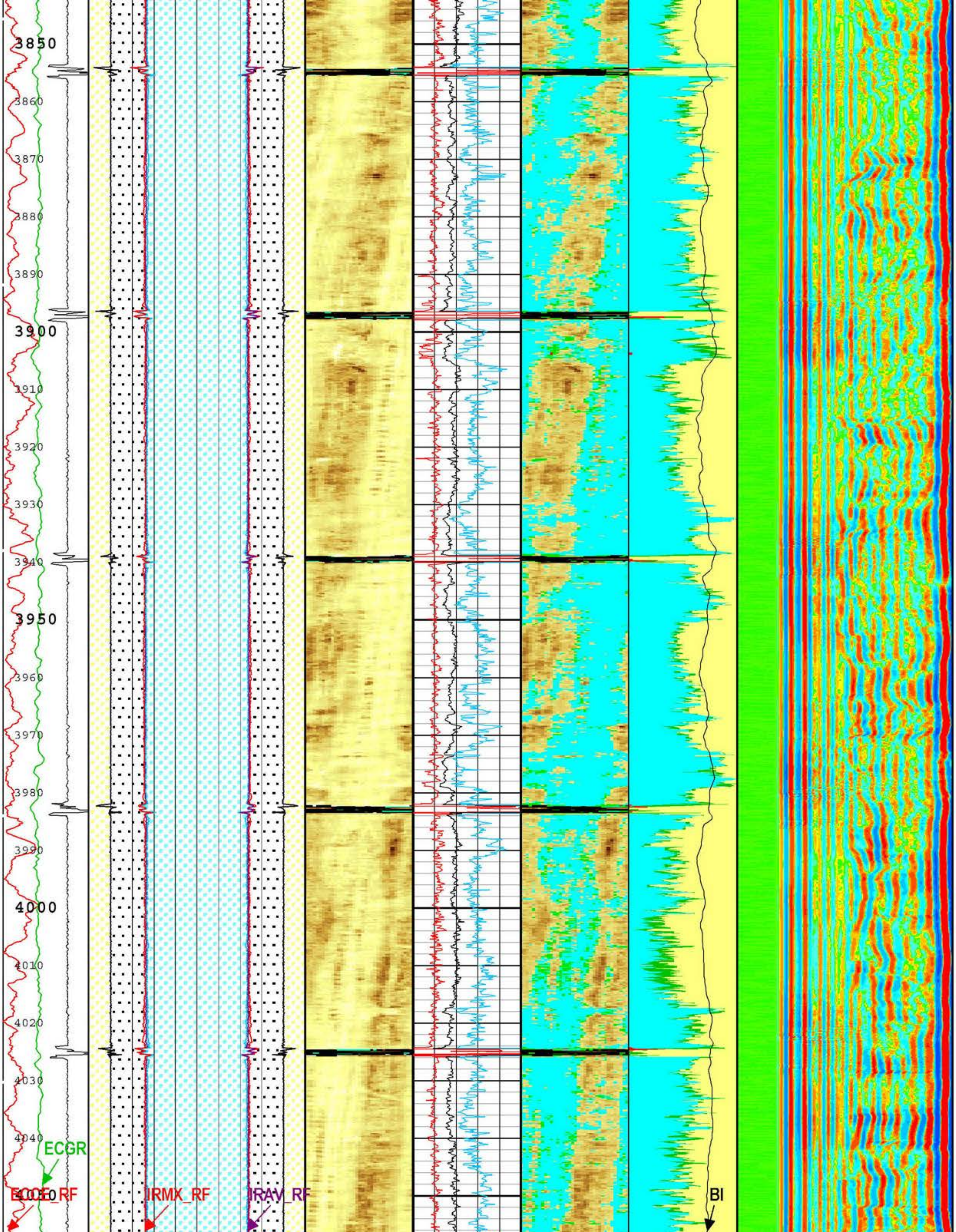
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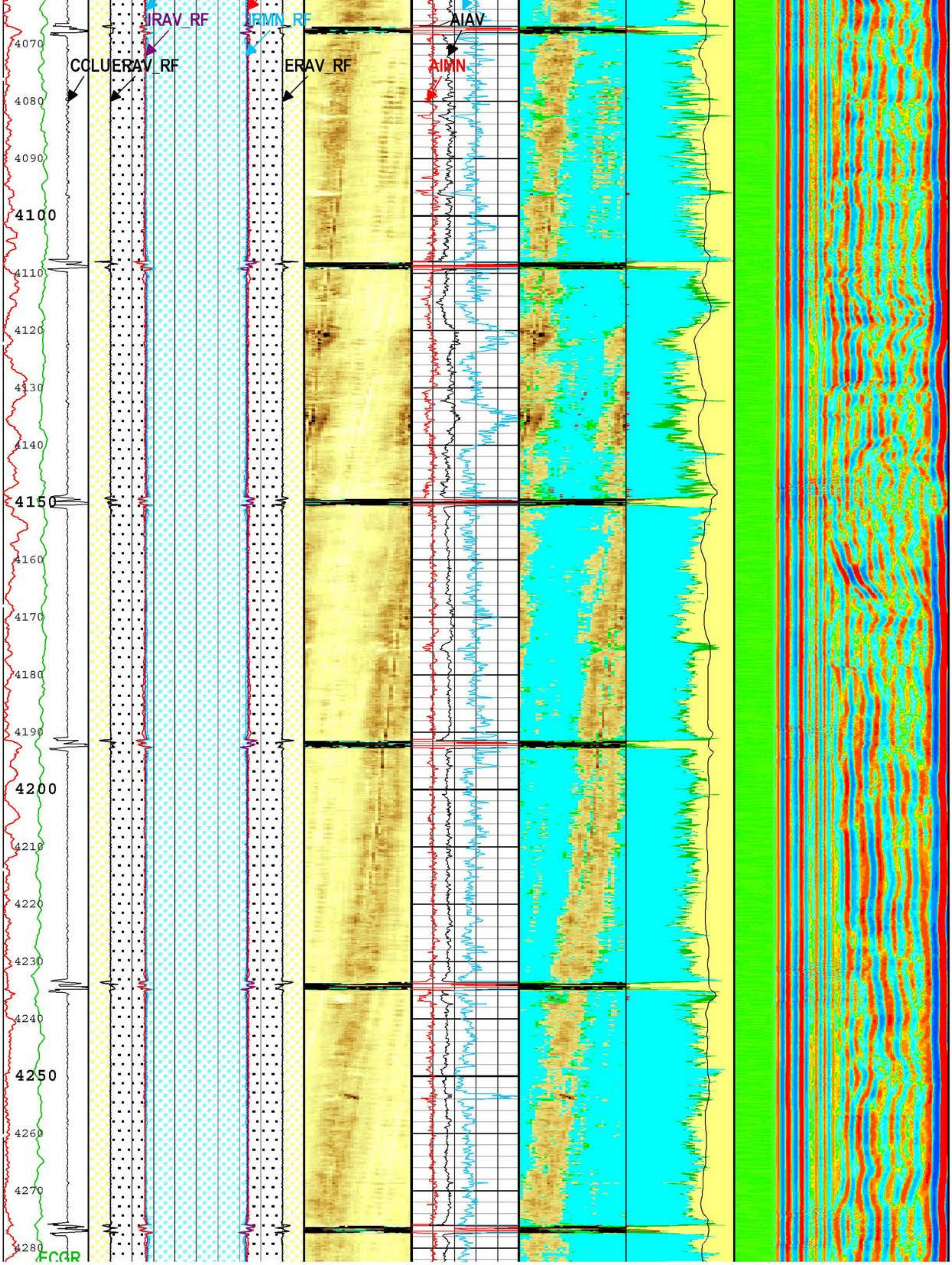
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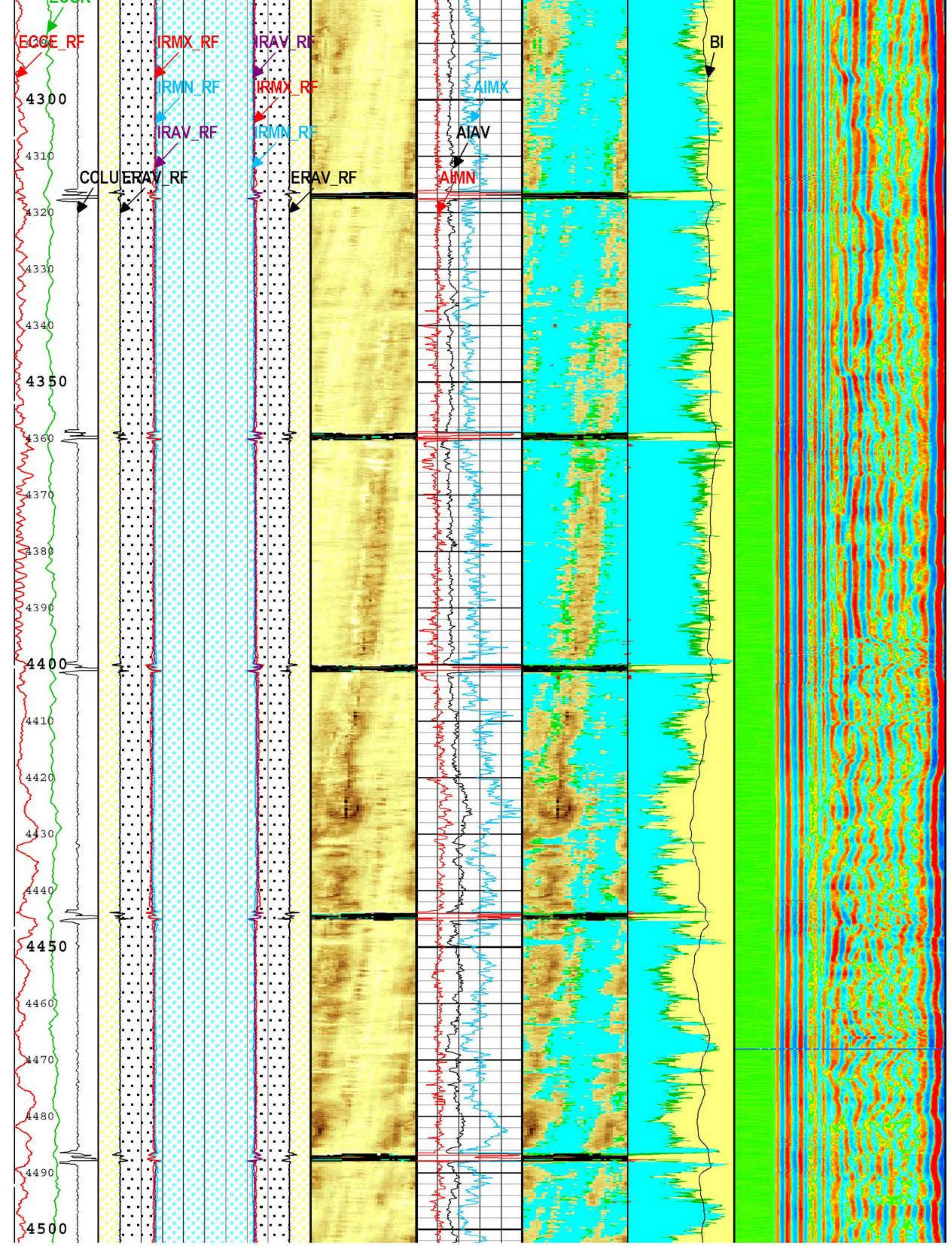

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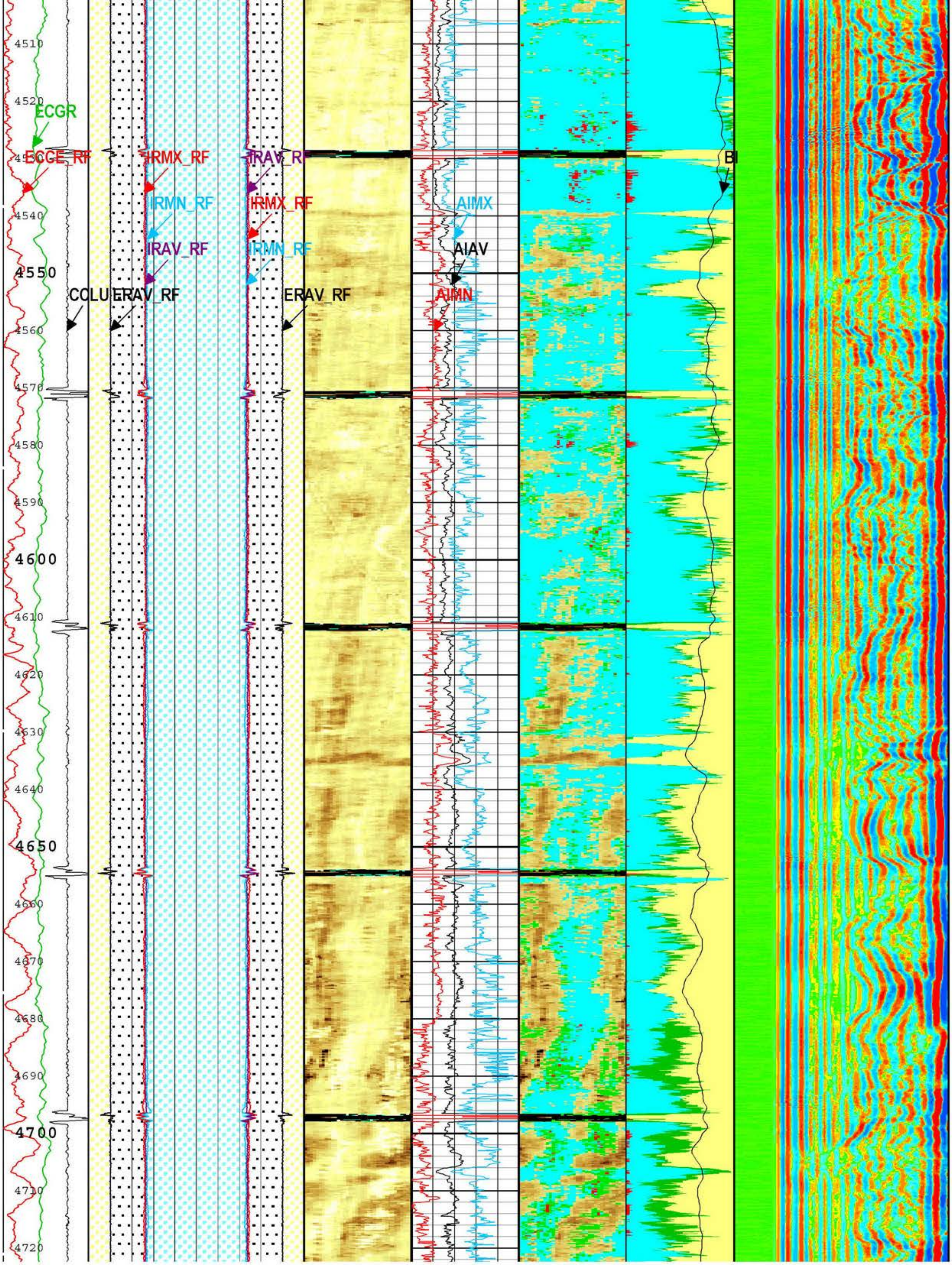

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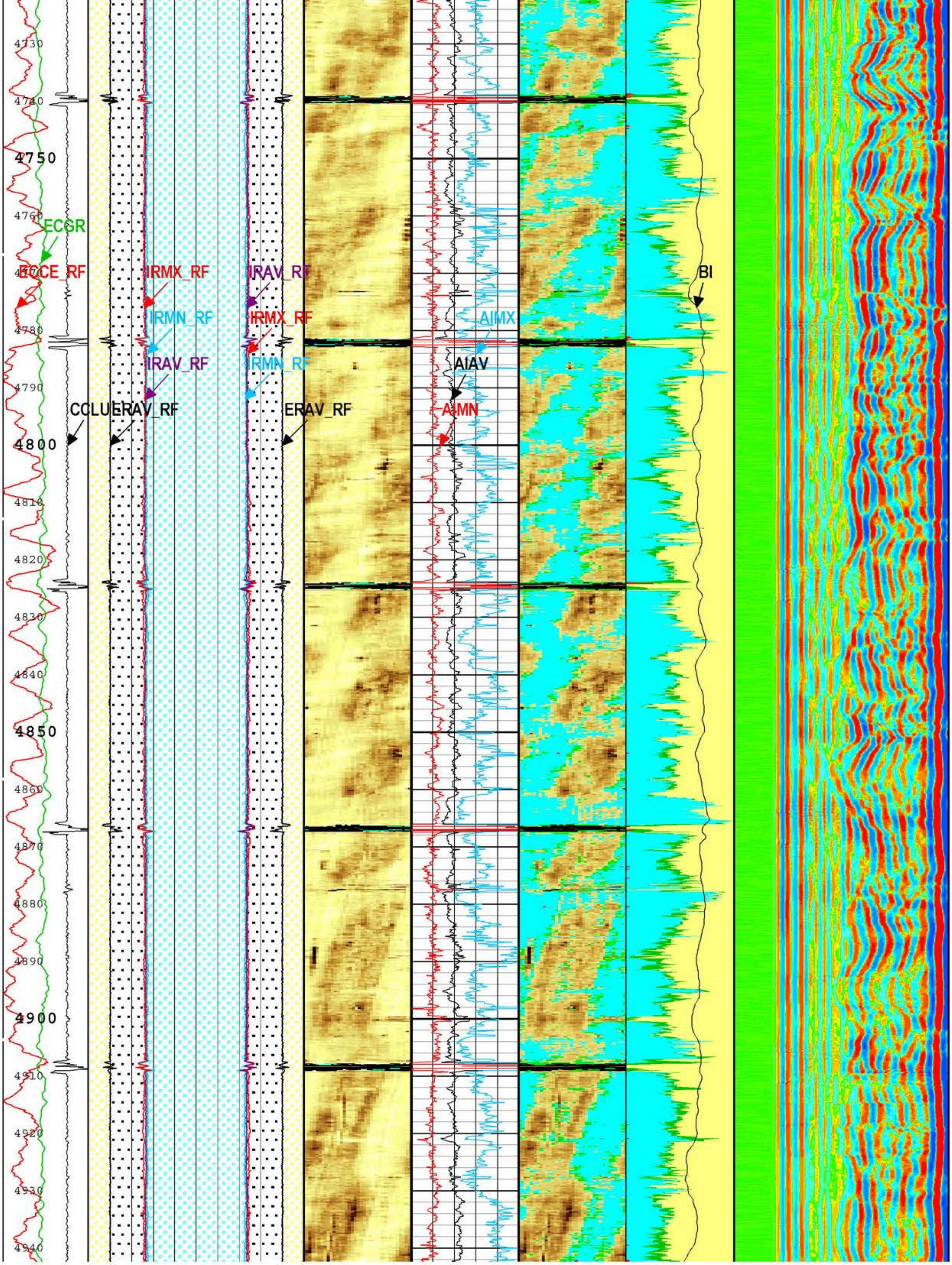

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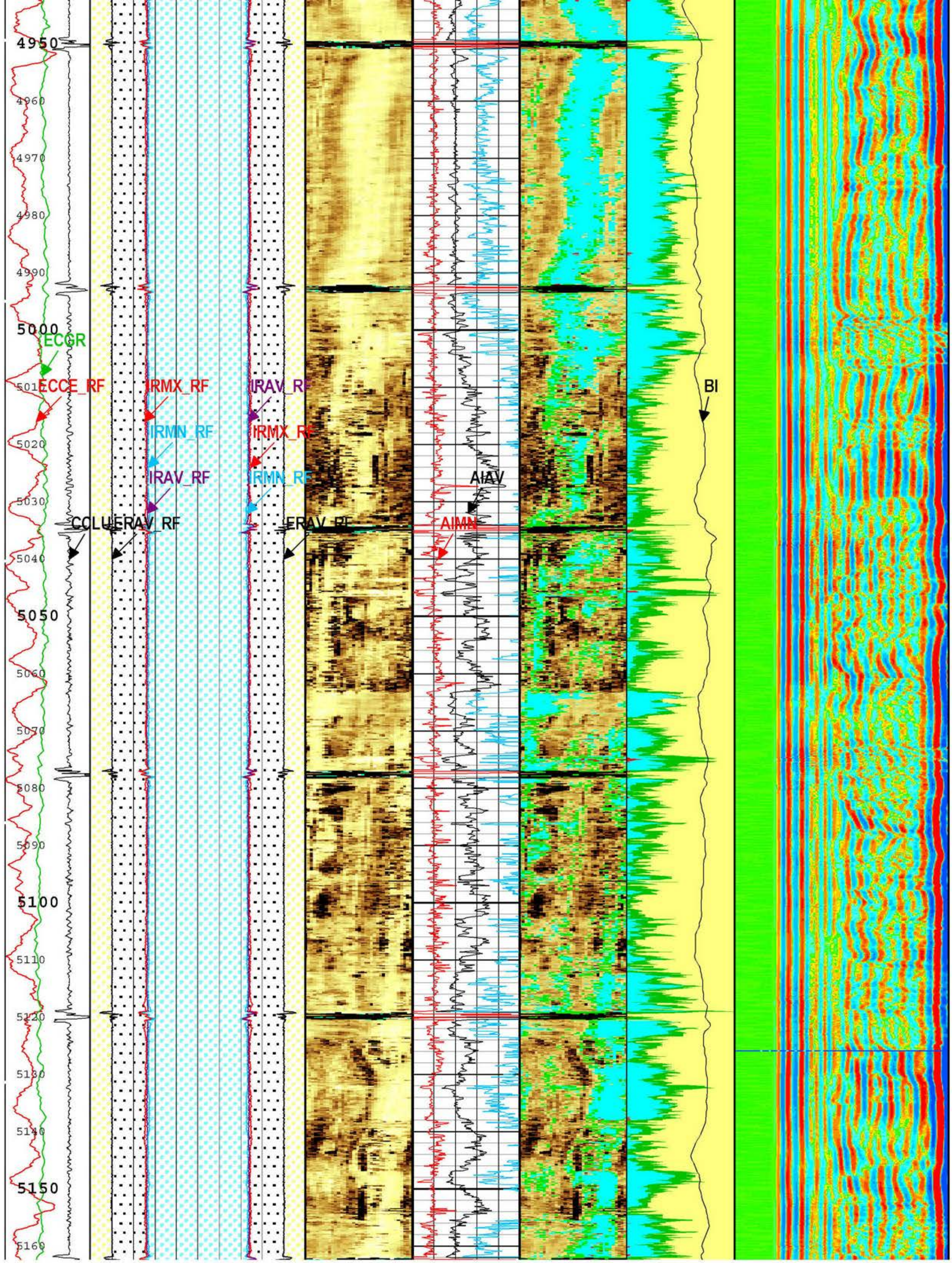
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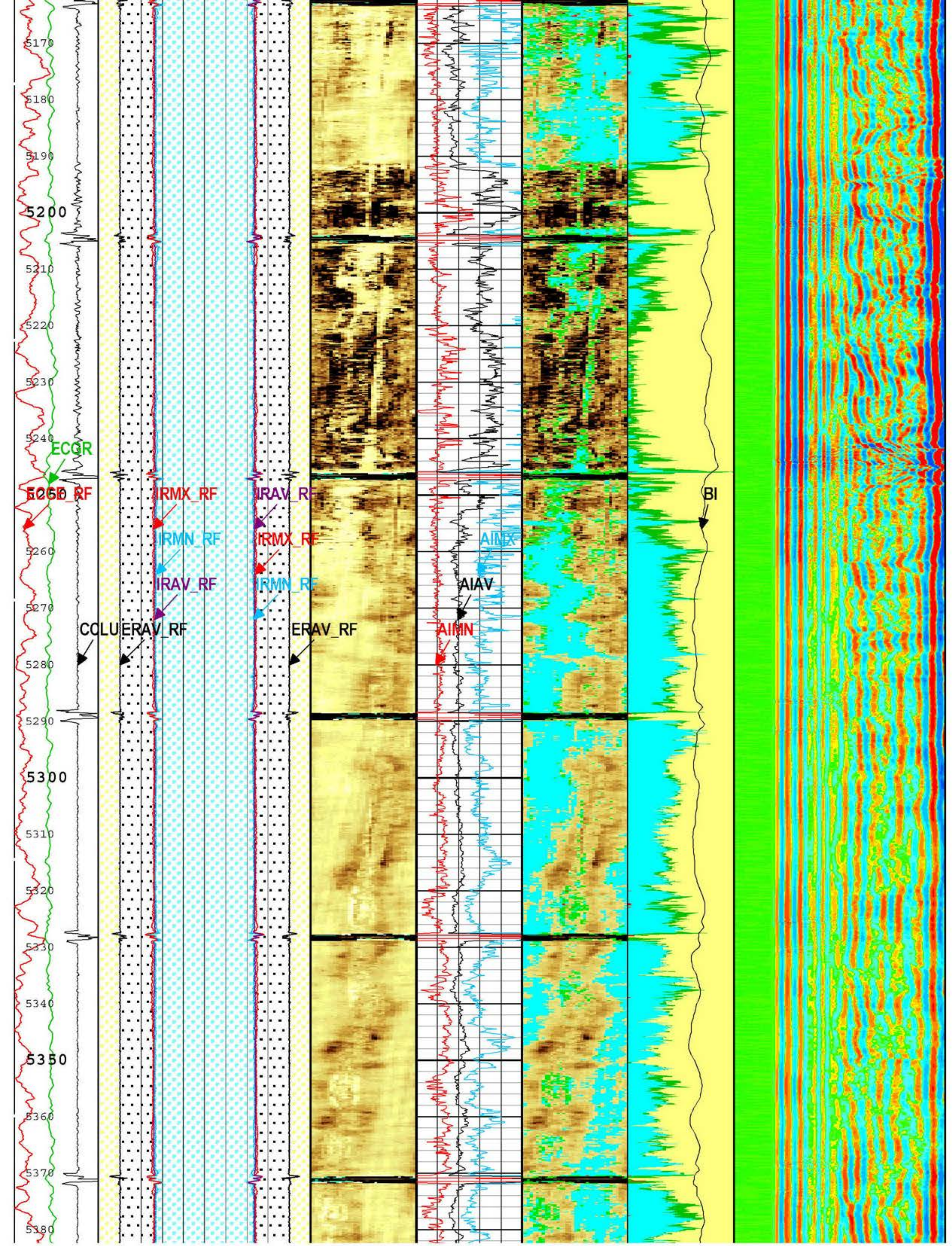
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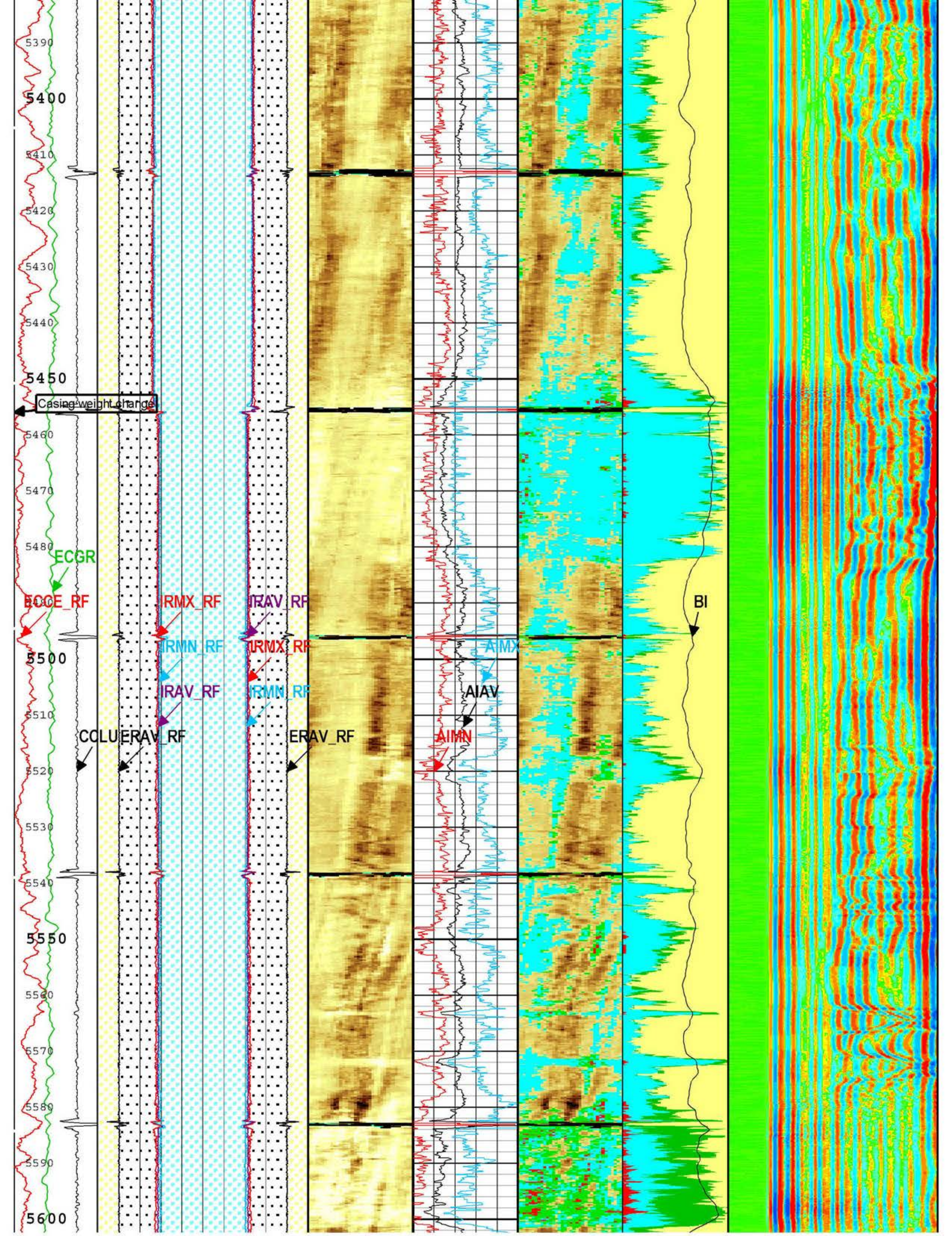

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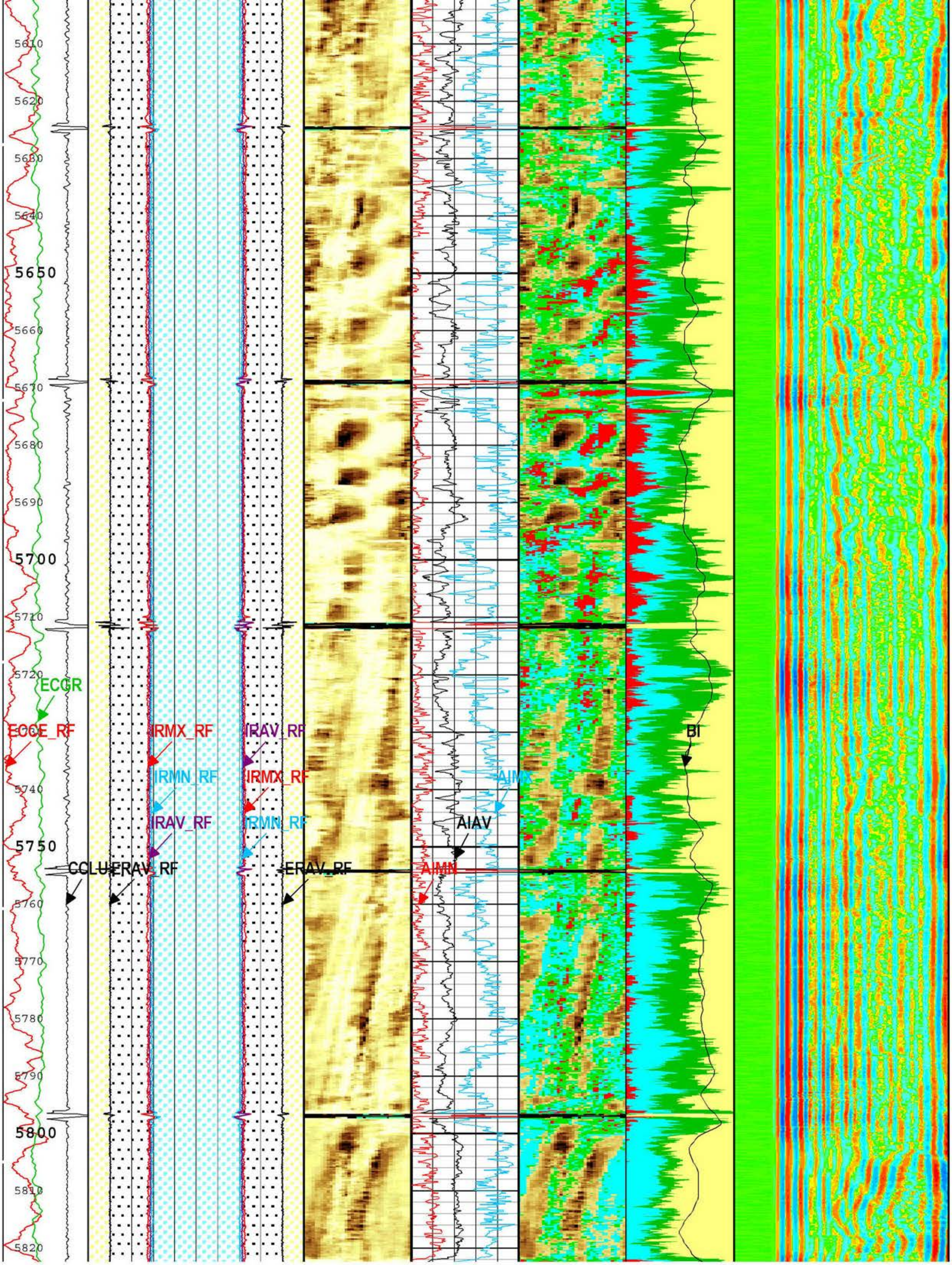
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