REDUCING ARTIFICIAL LIFT FAILURE RATE THROUGH OPTIMIZED TUBING INSPECTION

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ABSTRACT

Tubing inspections can provide valuable insight on the condition of tubing as well as the distinction between causes of tubing degradation. The results of these inspections are highly effective in preventing failure mechanisms in production wells resulting from corrosive downhole environments, mechanical aspects of artificial lift or a combination thereof. Tubing inspection data is utilized to replace worn and pitted tubing joints, facilitate failure root cause analysis and implement solutions to mitigate future failures. Due to the high cost of a tubing failure, a high-quality tubing inspection is critical to identify potential failure mechanisms, make design changes and ultimately extend the life of future tubing strings.

This paper serves to discuss the engineering and economic benefits of tubing inspection. The results of an in-plant inspection compared to a wellhead inspection on two Anadarko wells in the Permian Basin exemplifies said benefits. This paper provides an in depth analysis of tubing inspection technology, the pros and cons of both wellhead and in-plant inspections and data utilization to reduce downhole failures.

BACKGROUND

The following overview serves to provide the reader with a basic understanding of American Petroleum Institute (API) standards of used tubing, wellhead tubing inspections and in-plant tubing inspections.

Importance of Tubing Inspection Programs

There are a wide range of tubing grades available, which are categorized by size, weight, grade and material properties. Tubing inspection serves to evaluate the integrity of new or used tubing and identify any potential defects. New API tubing is inspected at the mill in accordance with API Spec 5CT, *Specification for Casing and Tubing,* to check physical properties such as dimensions, weight, length and straightness[11].

Typical defects in used tubing result from either corrosion, mechanical wear, erosion or a combination thereof[7]. Thorough tubing inspection can help an operator identify the root cause of failure in a tubing string and implement a solution to optimize life of the downhole equipment. Some potential solutions to problems identified in tubing scans are rod guides, chemical treatment programs and internal plastic coating. A paper presented at the Southwest Petroleum Short Course (SWPSC) in 1991 titled *Advanced Electromagnetic Tubular Inspection during Well Service* discusses the importance of real time tubing inspection in workover operations. The paper states real time inspections can be used to build a wall-loss profile over time with respect to position in the well[10]. Determining the rate of service-induced wear over time for any artificial lift type is important in order to implement solutions during workover operations before the well is brought back online.

API Specifications for Used Tubing Inspection

API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing*, gives guidelines for the inspection and handling of used tubing. According to API RP 5C1, presently accepted methods of inspecting the body section of pipe are visual, mechanical gauging, electromagnetic, eddy current, ultrasonic and gamma ray. There are a variety of internal and external service induced defects commonly identified in pipe inspection such as corrosion, wireline, slip and tong cuts, transverse cracking and sucker rod wear. When inspecting the threads of used casing and tubing, pulled round threads, galling and fatigue cracks should be checked. API RP 5C1 states the only acceptable wall thickness measurements are those made with pipe wall micrometers, sonic pulse-echo instruments or gamma-ray devices within 2% accuracy. API RP 5C1 recommends classifying used tubing according to the loss of nominal wall thickness and furthermore specifying the thickness with a standardized color-coding system (see Table 1). The visual identification consists of a paint band of color approximately 2 inches wide around the body of the pipe and approximately 1 foot from the box end[5].

Wellhead Tubing Inspections

The two most common methods of used tubing inspection are wellhead inspections and in-plant inspections. Wellhead inspections occur as tubing is being tripped out of hole (see Figure A) and can consist of visual inspection, calipering, hydrostatic testing, electromagnetic testing and gamma measurement. Wellhead inspections allow an operator to lay down tubing with defects above a specified threshold and replace rejected joints. Wellhead inspections have the benefit of correlation of tubing joint to depth as tubing is pulled out of hole (POOH) and inspected sequentially. This process provides an operator with a map of the condition of tubing. If the condition of tubing and the date of installation is known, an operator can determine the rate of wall loss over time and use this data for optimization immediately after tubing is POOH. Wellhead inspections are critical for use in failure analysis and artificial lift optimization. However, potential defects can be overlooked by wellhead inspections due to factors such as inspector experience, variance in pulling speeds and shortcomings of wellhead inspection technology.

A paper titled, *Preventing Tubing Leaks in the Field "A Reality Check"*, presented at the 2006 SWPSC, discusses the application of on-lease technology and outcome variability depending on the field application and interpretation. For example, the range in tubing scanning speed directly impacts the charted response and final interpretation of data. In this paper, out of four scanning companies studied over multiple jobs, only one company provided formal training for technicians, two could measure speed of the pull and two calibrated equipment prior to the job[6]. These findings emphasize the importance of understanding the quality of the inspector and accuracy of wellhead scanning technology.

Wellhead inspection units employ either non-contact Electromagnetic Induction (EMI) only or a combination of contact EMI and gamma. Due to the widespread use of non-contact EMI-only scanning units, many operators believe this type of unit provides a complete and accurate inspection. However, non-contact EMI-only scanning units work best for a uniform body and have challenges detecting longitudinal defects and pipe eccentricity. These challenges are due to the fact non-contact EMI-only units utilize Hall sensors, which physically do not make contact with the outer surface of tubulars. These Hall sensors have inherent challenges in detecting wall loss. Shortcomings include the reduction of signal resolution with distance from the pipe surface, improper centralization and varied tubing speed through the sensors. By the time signal reaches the Hall sensor, signal strength can be reduced, potentially registering an incorrect indication. Units utilizing contact EMI Hall sensors ride directly along the outside of the tubing body and receive immediate signal when a change in magnetic flux is detected.

Anadarko found effective API wellhead inspection results from a combination of contact EMI and gamma technology, which best reflects the combination of technology used during in-plant inspections to identify both transverse and longitudinal flaws. Gamma is an effective method, employed within in-plant inspections worldwide, for detecting longitudinal defects and measuring remaining body wall in tubing. Wellhead utilization of micrometers and sonic pulse micrometers can prove time and cost prohibitive.

A case study presented in 2016 at the SWPSC titled, *Rod Guide Strategy for Sucker Rod Pumped Wells in the Eagle Ford Shale*, discussed the failure of an EMI tubing scanning unit to detect wall loss that correlated to the wear pattern observed on the rod couplings and guides. After 42 days, a failure likely occurred due to tubing with significant wall loss being ran back in hole. The author concludes tubing scanning with both EMI and gamma technology for both transverse and longitudinal defects is better for rod pump wells than EMI-only inspection units, which can overlook longitudinal defects in rod pump wells[8]. This is similar to Anadarko's findings which will be presented in the following section.

Plant Tubing Inspections

Historically, in-plant tubing inspections have been used to sort classifications of tubing rather than a tool for well optimization. This is primarily due to inability to correlate a tubing joint to depth in a well as tubing joints become rearranged during transportation. In-plant tubing inspections generally provide a more comprehensive inspection than wellhead inspections due to processing in a controlled environment.

Tubing inspected in-plant undergoes visual inspection to identify corrosion and physical damage, internal and external removal of scale and paraffin, full-length drift to identify I.D. restrictions and ensure API specifications, EMI of tube body to detect transverse service-induced flaws (ie. corrosion pitting), gamma of tube body to identify longitudinal defects (ie. rod wear), visual inspection to detect thread and end area defects and application of thread dope and thread protectors. The data received from in-plant inspections is presented as a report detailing the total number of tubing joints, classified by color due to wall loss as well as the reason for downgrade (see Figure B). While in-plant tubing inspections provide the most thorough inspection, wellhead inspections serve as an essential tool to acquire well data for immediate optimization. If in-plant inspection were to provide a correlation to depth, it would provide the most comprehensive and accurate inspection for artificial lift optimization but without the immediacy of data provided by wellhead inspections.

ANADARKO'S TUBING INSPECTION PROGRAM

Previous Tubing Inspection Practices

Anadarko's West Texas Tubing Inspection Program has been evolving since its inception in 2014. Prior to 2014, Anadarko's WTX Workover Operations Team would hydrotest used tubing when running back in hole; replacing any suboptimal joints with new tubulars. This practice was an inefficient use of rig time and did not provide the team with data for design optimization. In early 2014, the team identified holes in tubing (HIT) as the most common failure mechanism in rod pump wells and began exploring ways to mitigate these failures. The solution was a contact EMI & gamma mobile scanning unit in addition to hydrotesting the tubing. This new practice presented the production engineers with real-time tubular integrity data, which allowed the team to design an optimal tubing and rod string prior to running back in hole. As a result, the HIT failure rate decreased from 0.66 failures/well/year to 0.21 failures/well/year in under two years of implementation. The failure rate is calculated by summing the number of failures in the preceding 12 month period divided by the well count at the end of a given period in time.

In 2016, Anadarko implemented Class 1, Division 1 (C1D1) Electrical Classifications. Unfortunately at that time, the contact EMI & gamma mobile unit did not meet the C1D1 criteria. Therefore, an existing C1D1 non-contact EMI-only mobile scanning unit was deployed across the field. About a year into the program, the scan quality of the unit became questionable due to several instances where a tubing joint scanned yellow but failed the hydrotest. As a result, Anadarko sought out alternate solutions and decided to trial in-plant inspections as outlined in the following two case studies.

Case Study #1: Verde 34-153 1H

The Verde 34-153 1H was worked over for a suspected failed downhole insert pump. 315 joints of tubing were scanned on location with a non-contact EMI-only unit while tripping out of hole. The tubing was then transported and taken through an in-plant inspection facility. Major discrepancies between both data sets were found, as evident in Table 2, Figure C and outlined in the results section.

Case Study #2: Monroe 34-158 1H

The Monroe 34-158 1H was also worked over for a suspected failed downhole insert pump. 321 joints of tubing were scanned on location with a non-contact EMI-only unit while tripping out of hole. The tubing was then transported and taken through an in-plant inspection facility. Similar to Case Study #1, major discrepancies between both data sets were found, as evident in Table 3, Figure D and outlined in the following results section.

Results

The results of the tubing scans in both case studies exhibited discrepancies between wellhead inspection and in-plant inspection. In Case Study #1, the plant and EMI wellhead scans only agreed for 70% of tubing joints inspected. The EMI wellhead scan missed 64 joints of red band tubing: 54 downgraded due to rod wear and 10 due to pin end damage. In Case Study #2, the plant and EMI wellhead scans agreed for 96% of tubing joints. The EMI wellhead scan missed 2 joints of green band tubing and 6 joints of red band tubing: 2 downgraded due to mechanical damage, 4 mashed and 2 to rod cut.

The variance between the results of in-plant and wellhead inspection in both cases warrants investigation into the error rate of non-contact EMI-only wellhead inspection. Some wellhead tubing scanning technology has inherent challenges in determining accurate wall loss for the entirety of a given tubing joint. Specifically, measurement of the upsets, threading and connections are difficult for the common mobile scanning unit. This would explain the discrepancies in joints downgraded due to pin end damage. However, this does not explain the discrepancies in wall defects due to rod cut and mechanical damage.

Exploration of resources regarding non-contact EMI-only technology yielded some explanations. New Tech Systems, a non-contact EMI-only manufacturer, published an article in *Crosstalk* elaborating on these shortcomings stating “small and/or large areas of wall loss that occur gradually over an area are not detectable.”[12] This would be applicable to areas affected by rod cut, where the losses occur over an area in the longitudinal plane due to the reciprocation of rods. An article titled *EMI Wall Loss Detection in Plain English* discusses the inability of magnetics in EMI-only scans to measure remaining wall thickness, although often erroneously claimed capable of such. Non-contact EMI-only scanning technology is not considered an industry standard method for calculating average cross-sectional area according to API.[4]

Therefore, non-contact EMI-only wellhead inspections are not suitable for measuring accurate wall loss due to longitudinal defects. Additional inspection technology should be used to prove the extent of wall loss for true determination of remaining body wall as per API standards. Given the additional rig time incurred through use of pipe wall micrometers or ultrasonic gauges, a combination of contact EMI and gamma inspection technologies is the most viable option for an accurate wellhead scan. The amalgamation of these two technologies maximizes inspection resolution within API standards and minimizes overall rig time.

According to failure information provided by Anadarko, inaccurate scans likely contributed to 14 HIT workovers between 2016 and 2017 due to compromised tubing integrity when red-banded joints were misclassified and run back in hole. This hypothesis was formulated based on the analysis of workovers due to HIT shortly following non-contact EMI-only wellhead tubing scans. Millions of dollars in workover costs could have been saved if more accurate scanning technology was utilized during these operations.

Anadarko performed an economic analysis of wellhead and in-plant inspections, which supported the standardization of in-plant inspection for all tubing. During these trials, the entire string of tubing was POOH, sent to an in-plant facility and replaced with API yellow-banded or new tubulars. This practice led to an average reduction of rig time by two days. The optimized rig time is a result of faster tripping speeds, decreased non-productive time (NPT) waiting for pipe to arrive on location, less hot watering required prior to POOH, decreased NPT to sort pipe and eliminating the hydrotest when running in hole. Per workover, Anadarko saved on average approximately 22% utilizing in-plant inspection over field scanning. These savings do not include the reduction of all daily rig costs per job nor deferred production cost savings from getting the wells back online sooner. Foregone, however, is the ability to immediately acquire data regarding the condition of tubing as it is POOH and the intangible cost of immediate data for design optimization. That being said, currently the average turn-around time from when the pipe leaves location to a completed inspection report is seven days. Due to the extent of the historical well database in addition to C1D1 requirements, Anadarko believes the benefits of scanning in-plant outweigh the costs of having data on tubing quality available immediately after POOH.

Current Tubing Inspection Program

Anadarko’s current West Texas Tubing Inspection Program encompasses only in-plant inspection for all tubing POOH. New or reconditioned yellow-band tubing is then run back in hole, eradicating the risk of running compromised tubing back in hole. This practice has enabled the Production Engineering team to track a true failure rate and analyze the performance of the downhole equipment over time. The lag time before receiving the tubing inspection reports compared to mobile scanning has not hindered data utilization for future workovers and downhole designs. Since replacing mobile scans with in-plant scans in 2017, Anadarko has reduced the 12 Month Average HIT Failure Rate by 0.05/well/year and the overall 12 Month Average Artificial Lift Failure Rate by 0.16/well/year to achieve a current 12 Month Average Artificial Lift Failure Rate of 0.29/well/year as of January 2019.

Anadarko is working with Tuboscope to develop a process to correlate in-plant tubing inspection data with depth, enabling advanced design optimization and failure rate reduction. Figure E and F exemplify in-plant tubing inspection results for wells on two different types of artificial lift. The Super Duty 29-16 1H, a gas lift well, failed due to holes in tubing. When determining the root cause of failure, correlating the tubing inspection to depth was critical in understanding the location of corrosion and how to mitigate in the next design iteration. Consequently, Anadarko optimized the downhole design by running a full string of internally coated tubing and gas lift mandrels. The Monroe 34-188 1H, a rod pump well, failed due to parted rods. Utilizing a Rod Guide Advisory Program (RGAP) and correlating the tubing inspection to depth, Anadarko was able to determine the well's root cause of failure and optimize the rod string by adding guides (see Figure G). For both the Super Duty 29-16 1H and Monroe 34-188 1H, the tubing inspection report correlated to depth was imperative in order to advance the root cause of failure discussion and formulate recommendations for subsequent workovers.

CONCLUSION

Anadarko's implementation of a tubing inspection program in 2014 has made a significant impact in the artificial lift failure rate. Contact EMI & gamma wellhead tubing scanning provided the production engineering team with valuable and immediate data to optimize the downhole design prior to running back in hole. C1D1 requirements restricted the tubing scanning unit to non-contact EMI-only technology at that time, which overlooked several instances of rod cut. Over time, Anadarko built up a well-documented historical failure database and transitioned to in-plant tubing inspection in order to track a true failure rate. Present day, in-plant tubing inspection remains Anadarko's primary method of tubing inspection. Data from tubing inspections has been critical in analyzing root cause of failure and reducing the artificial lift failure rate over the past several years. The variety of tubing inspection technologies currently available can provide valuable insight in a well's failure history and can be utilized in optimizing downhole designs. Weighing the benefits and shortcomings of each type of tubing inspection technology is key in order to select the optimal technology given a company's current operational needs.

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Table 1. API RP 5C1 Tubing Thickness Color Coding

COLOR	MINIMUM WALL LOSS (%)	MAXIMUM WALL LOSS (%)
Yellow	0	15
Blue	16	30
Green	31	50
Red	51	100

Table 2. Verde 34-153 1H Tubing Inspection Results

SCAN CLASSIFICATION	EMI MOBILE TUBULAR COUNT (JOINTS)	PLANT TUBULAR COUNT (JOINTS)
Yellow	256	160
Blue	59	91
Green	0	0
Red	0	64 (54 Rod Wear & 10 Pins)

Table 3. Monroe 34-128 1H Tubing Inspection Results

SCAN CLASSIFICATION	EMI MOBILE TUBULAR COUNT (JOINTS)	PLANT TUBULAR COUNT (JOINTS)
Yellow	310	297
Blue	10	15
Green	1 (Rod Wear)	3
Red	0	6 (2 Mech Damage & 4 Mashed)

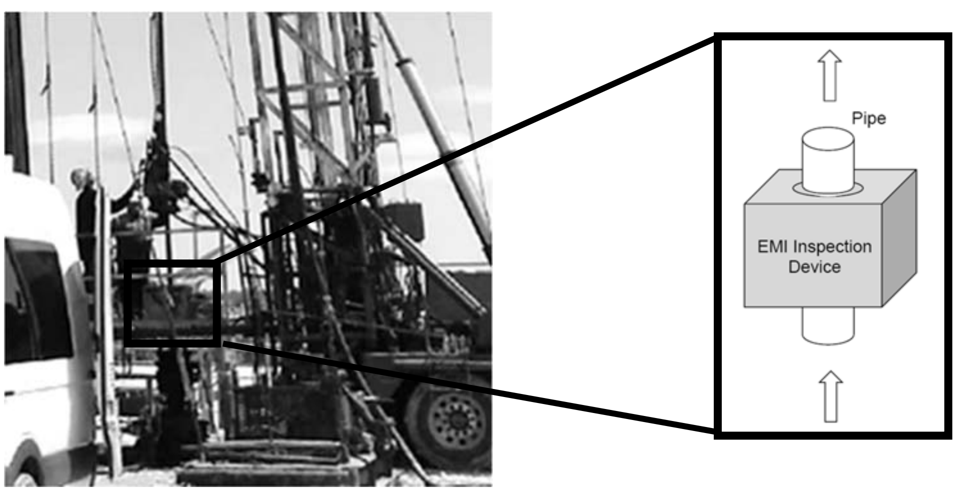

Figure A. Mobile Tubing Inspection Equipment

INSPECTION REPORT OF USED TUBING / CASING

CUSTOMER ANADARKO DATE

LOCATION WORK ORDER NO.

WELL NAME & NUMBER MURIO 34-223 UNIT 31I CUSTOMER ORDER NO.

DESCRIPTION AS PRESENTED BY CUSTOMER

149	2 7/8	BARE	#2	
Lengths	Size	Type of Pipe	Range	Manufacturer
6.5	.217	L-80	8RD	2.347
Weight	Wall	Grade	Connection	Drift Diameter

Service Codes: EIS

Type Of Inspection: EMI FLD VTI

/ API RP5C1 / Sec. 4

API Customer Specs.

SUMMARY OF RESULTS

119 Lengths Class II Pipe Indications not exceeding 15 % of the specified body wall thickness identified by one YELLOW paint band.

No-Drift	Bent	Damaged Coupling	Damaged Field End	Both P&B
		30	/	

Lengths Class III Pipe 16 % To 30 % of specified body wall thickness Identified by one BLUE Paint band

Pitting	Wear	Mashed or Damaged	Erosion		No-Drift	Bent	Damaged Coupling	Damaged Field End	Both P&B

Lengths Class IV Pipe 31 % To 50 % of specified body wall thickness Identified by one GREEN Paint band

Pitting	Wear	Mashed or Damaged	Erosion		No-Drift	Bent	Damaged Coupling	Damaged Field End	Both P&B

30 Lengths Class V Pipe 51 % To 100 % of specified body wall thickness Identified by one RED Paint band

Pitting	Wear	Mashed or Damaged	Erosion		No-Drift	Bent	Damaged Coupling	Damaged Field End	Both P&B
/								/	

Lengths received only a visual evaluation and were found to be damaged to such an extent as to preclude inspection.

Mashed or Mech. Damaged	Bent	Corkscrew		

149 Total Lengths Inspected.

Serviced By

Color Code For Pipe Identification

Class II	Class III	Class IV	Class V	Bent	Mash	No Drift	Damaged Coupling	Damaged Field End	
Y	B	G	R						

Figure B. In-Plant Tubing Inspection Report

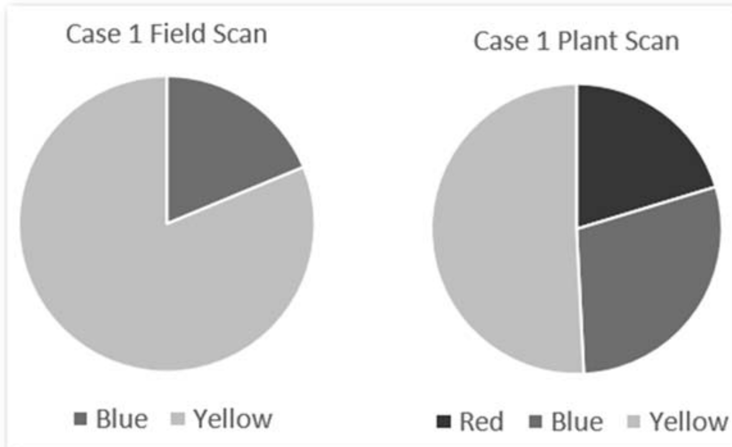

Figure C. Verde 34-153 1H Tubing Inspection Results

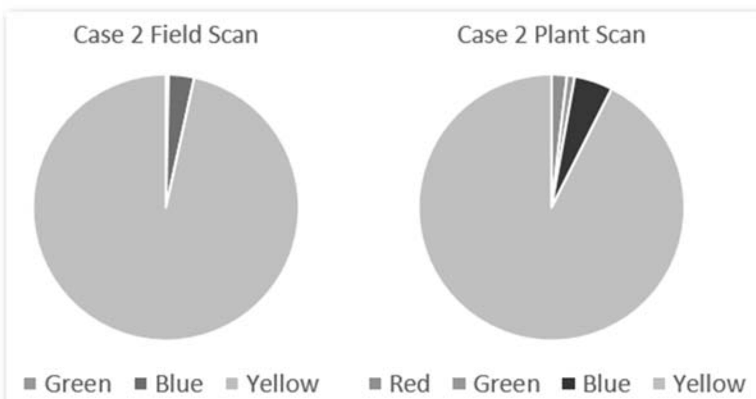

Figure D. Monroe 34-128 1H Tubing Inspection Results

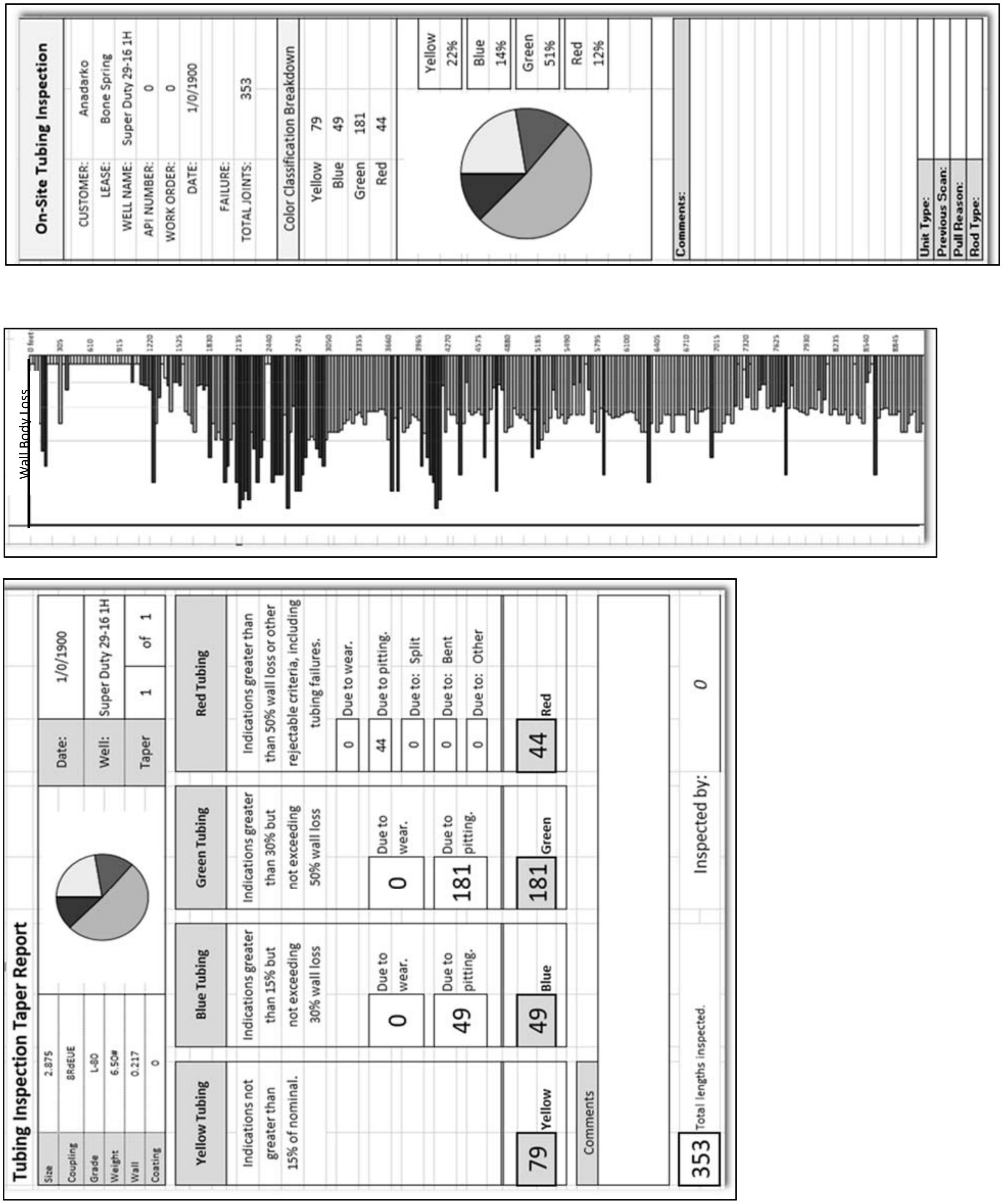

Figure E. In-Plant Tubing Inspection Report for the Super Duty 29-16 1H

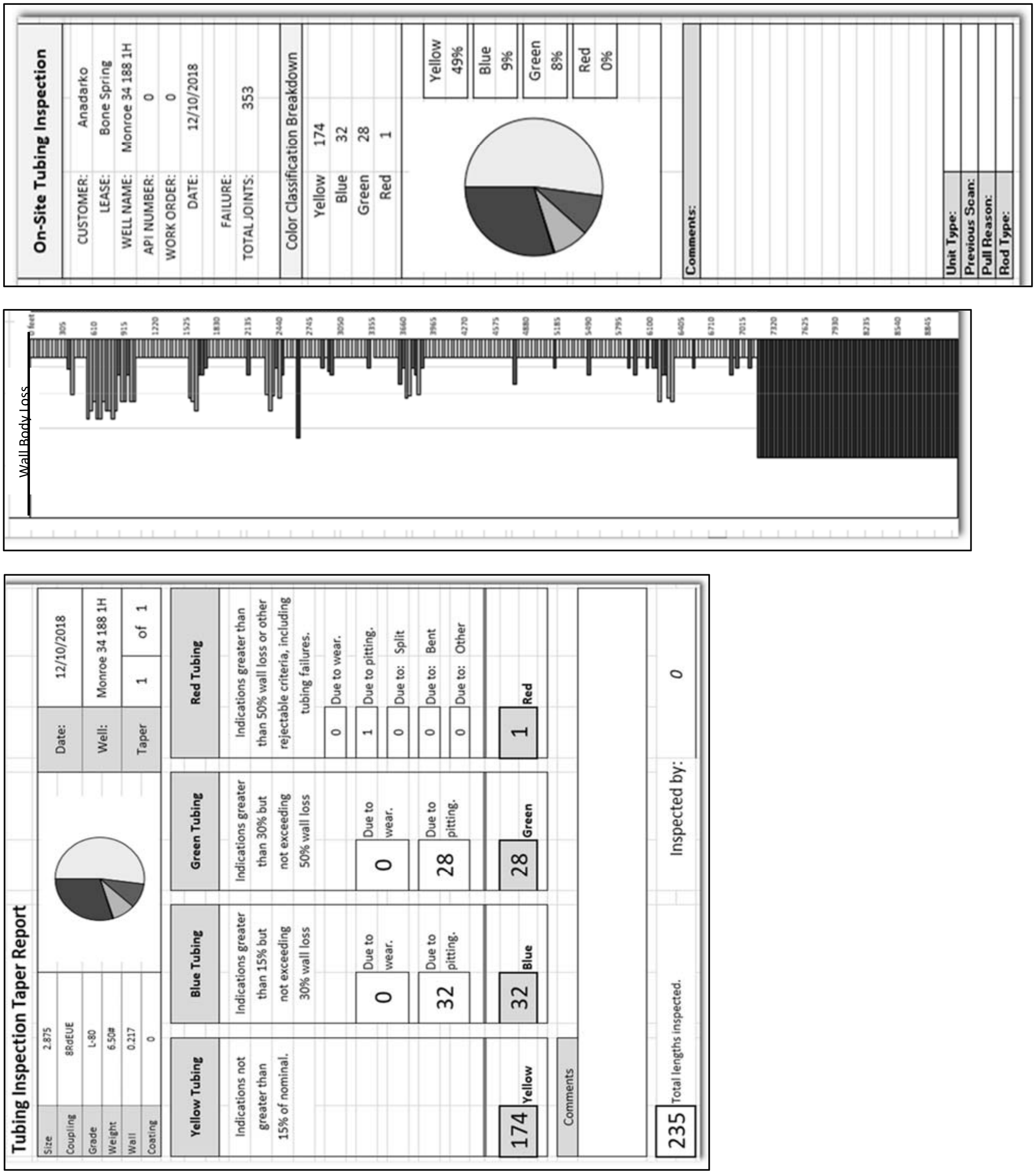

Figure F. In-Plant Tubing Inspection Report for the Monroe 34-188 1H

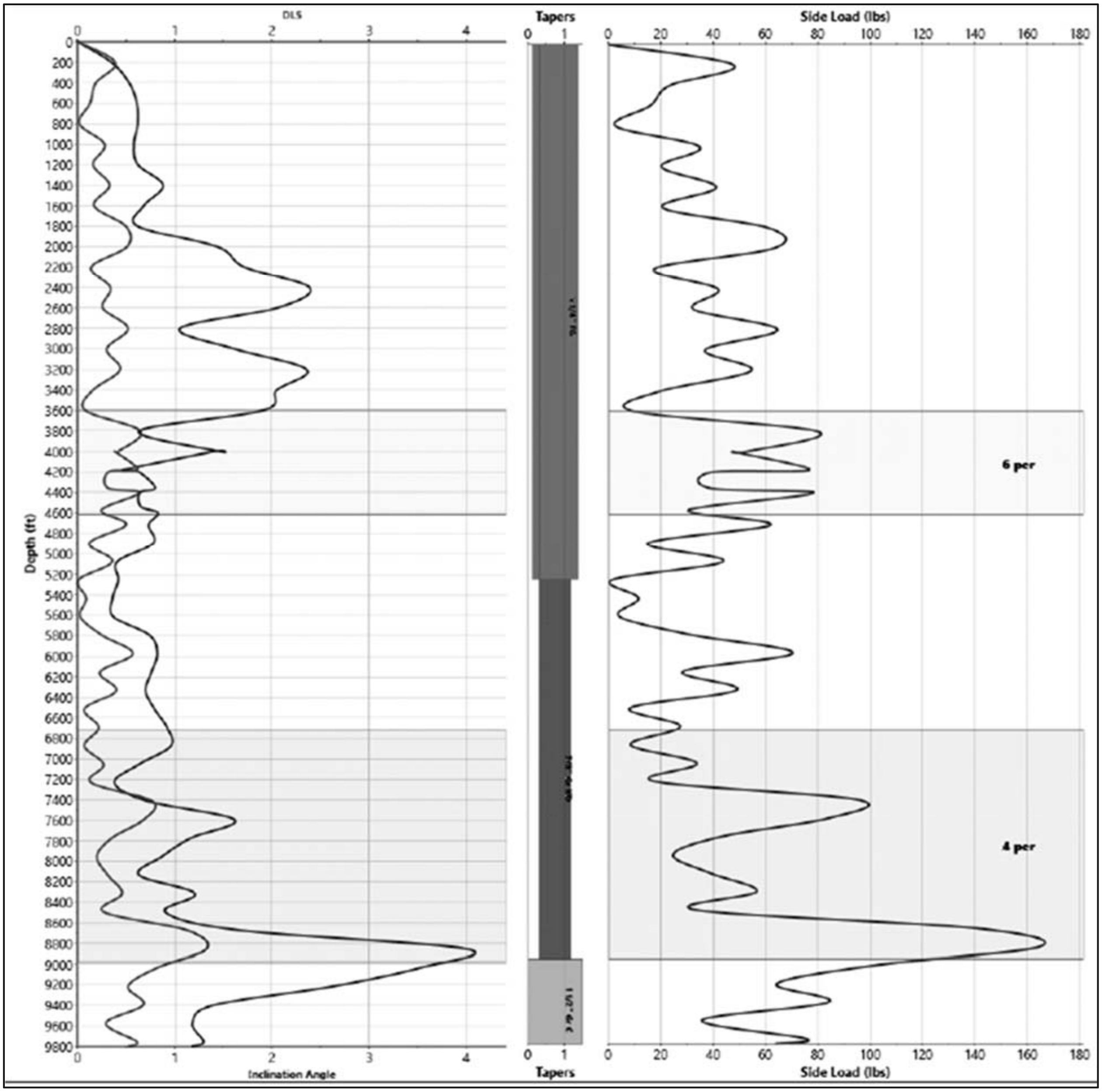

Figure G. RGAP Report for the Monroe 34-188 1H