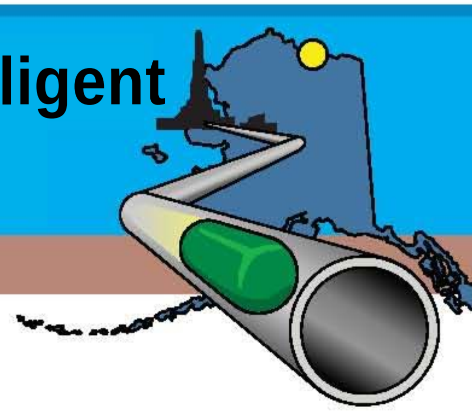
2006 Maintenance and Intelligent Pigging Conferences



Draft Conference Proceedings Report
Anchorage, Alaska

February 2007

Prepared For:

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EXECUTIVE SUMMARY

In April 2000, BP Exploration (Alaska), Inc. (BP), ConocoPhillips Alaska, Inc. (CPAI), and the Alaska Department of Environmental Conservation (ADEC) entered into an agreement under the Charter for Development of the Alaska North Slope (Charter). The Charter identifies eleven environmental commitments; one of these commitments is monitoring corrosion in the North Slope pipeline infrastructure. As part of the July 1, 2006 to June 30, 2007 environmental commitments, a pipeline integrity conference was convened in Alaska to ensure that the best minds, technologies and practices are employed in the design, operation and maintenance of Alaska's North Slope pipelines. A pipeline integrity conference Technical and Steering Committee composed of BP, CPAI, and the ADEC representatives identified maintenance and intelligent pigging as two topics desired for the pipeline integrity conference. A Maintenance Pigging of Pipelines Conference was held October 19, 2006, and an Intelligent Pigging of Pipelines Conference was held November 13, 2006.

Four maintenance pigging presentations were delivered during the October 19, 2006 Maintenance Pigging Conference. Six intelligent pigging presentations were delivered during the November 13, 2006 conference. Sixteen exhibitors representing maintenance and intelligent pigging products and/or services attended the conferences.

The October and November, 2006 pipeline integrity conferences provided state-of-the-art information about maintenance and intelligent pigging technologies. World experts discussed the latest advances and best practices in maintenance and intelligent pigging, and provided examples of how proven or promising technologies could be applied to Alaska's North Slope pipelines.

Pipeline integrity management programs have been established by the two main North Slope pipeline operators, BP and CPAI, to continuously evaluate pipeline conditions and to prevent pipeline failure. The State of Alaska and U.S. Department of Transportation have proposed regulations requiring that an additional 1500 miles of pipeline on the North Slope be included in the BP and CPAI integrity management programs. The proposed regulations may affect pipeline segments that have not been cleaned with a maintenance pig for many years. The pigging technologies and practices presented at the maintenance and intelligent pigging conferences may or may not be applicable for use on any given segment of pipeline. It is the task of the individual operators to determine how to incorporate the best pigging technologies and practices into their pipeline integrity management programs and into the design, operation, and maintenance of these Arctic pipelines.

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ACRONYMS AND ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
ADNR	Alaska Department of Natural Resources
AGM	Above Ground Marker
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BLM	Bureau of Land Management
BPXA	British Petroleum Exploration (Alaska), Inc.
CFR	Code of Federal Regulations
CPAI	ConocoPhillips Alaska, Inc.
CPF	Central Production Facility
CPIG	Cornerstone Pipeline Inspection Group
DOT	U.S. Department of Transportation
EDTA	Ethylene Diamine Tetra Acetic acid
EFRD	Emergency Flow Restricting Devices
EMAT	Electro Magnetic Acoustic Transducer
EOA	Eastern Operating Area
EPA	Environmental Protection Agency
GC1	Gas Compression Plant No. 1
GE	General Electric
GIS	Geographical Information System
GPS	Global Positioning System
HCA	High Consequence Area
HSE	Health Safety Environment
HSSE	Health Safety Security Environment
ICDA	Internal Corrosion Direct Assessment
I.D.	Inside Diameter
ILI	In-Line Inspection
IMP	Integrity Management Program
IPC	International Pipeline Conference
ISO	International Standards Organization
JPO	Joint Pipeline Office
LDP	Leak Detection Pigs

ACRONYMS AND ABBREVIATIONS

MAOP	Maximum Allowable Operating Pressure
MIC	Microbiologically Influenced Corrosion
MFL	Magnetic Flux Leakage
NACE	National Association of Corrosion Engineers
NTA	Nitrilotriacetic Acid
O.D.	Outside Diameter
OPS	Office of Pipeline Safety
OPD	Optical Observation Device
OQ	Operator Qualification
OT	Oil Transit
OTL	Oil Transit Line
PHMSA	Pipeline Hazardous Materials Safety Administration
PII	Pipeline Integrity and Inspection
PIMS	Pipeline Integrity Management System
PL	Pipeline
PODS	Pipeline Open Data Standard
QA	Quality Assurance
Q&A	Question and Answer
R&D	Research and Development
RP	Recommended Practice
RSS	Robot Survey System
RW	Radio Wave
ROV	Remotely Operated Vehicle
SAAM	Smart Acquisition Analysis Module
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
SPAR	Spill Prevention and Response
STP	Seawater Treatment Plant
TDW	TD Williamson
TFI	Transverse Flux Inspection
USCD	UltraScan Crack-Detection
USWM	UltraScan Wall Measurement
UT	Ultrasound Technology
VSM	Vertical Support Member
WOA	Western Operating Area

2006 MAINTENANCE AND INTELLIGENT PIGGING CONFERENCES
CONFERENCE PROCEEDINGS REPORT
ANCHORAGE, ALASKA

1.0 INTRODUCTION

BP Exploration (Alaska), Inc. (BP), ConocoPhillips Alaska, Inc. (CPAI) and the Alaska Department of Environmental Conservation (ADEC) entered into an agreement under the Charter for Development of the Alaska North Slope (Charter) in April 2000. At the direction of former Governor Frank Murkowski and with funding from the Charter, BP, CPAI and ADEC hosted two conferences in Anchorage, Alaska in October and November 2006. The Charter identifies eleven environmental commitments; one of these commitments is monitoring corrosion in the North Slope pipeline infrastructure. These pipeline integrity conferences were convened in Alaska, as part of the July 1, 2006 to June 30, 2007 environmental commitments, to ensure that the best minds, technologies and practices are employed in the design, operation and maintenance of Alaska's North Slope pipelines.

Pipeline integrity conference Technical and Steering Committees, composed of BP, CPAI, and the ADEC representatives, identified maintenance and intelligent pigging as two topics desired for the pipeline integrity conference. A Maintenance Pigging of Pipelines Conference was held October 19, 2006, and an Intelligent Pigging of Pipelines Conference was held November 13, 2006. The two conferences presented technical issues associated with maintenance and intelligent pigging of pipelines, and provided presentations from world pipeline pigging experts familiar with these technologies. The objectives of the conferences were:

- Gather information from around the world on pipeline pigging technology, including programs and equipment;
- Examine the latest technologies and best practices in maintenance and intelligent pigging and how proven or promising technologies could be applied to Alaska's North Slope pipelines; and
- Evaluate application of the best technologies and practices in the design, operation, and maintenance of these Arctic pipelines.

Shannon & Wilson coordinated with the Technical and Steering Committees to establish the subject of each talk, and to identify world experts to prepare and deliver each presentation. The morning session of the two conferences included presentations from experts familiar with current practices and recent advances in pigging programs, and tools and techniques for cleaning, in-line inspecting, and detecting corrosion of pipelines under Arctic conditions. Presenters also discussed: increasing the effectiveness of pigging runs, pigging of pipelines considered unpiggable, and the regulatory requirements and standards for intelligent pigging of North Slope pipelines.

Question and Answer (Q&A) Sessions were held with the presenters and an Industry and Regulatory Panel after each presentation. This was followed in the afternoon by Industry and Regulatory Panel Discussion Sessions to generate participation between the audience and members of the Industry and Regulatory Panel, presenters, service providers, and pig manufacturers. Members of the Industry and Regulatory Panel for each conference included representatives from BP, CPAI, ADEC, Pioneer Natural Resources Alaska (Pioneer), Alaska Department of Natural Resources (ADNR), Alaska Oil and Gas Conservation Commission (AOGCC), Bureau of Land Management (BLM) Joint Pipeline Office (JPO), and U.S. Department of Transportation (DOT) Office of Pipeline Safety (OPS). Tom McCloskey, of the McCloskey Group, moderated the Conference and introduced the speakers, presenters, and the Industry and Regulatory Panel members. The Moderator and/or the Industry and Regulatory Panel asked questions of the presenters.

The conferences were held at the Hilton Hotel, located at 500 West 3rd Avenue in Anchorage, Alaska. An Exhibit Hall was established adjacent to the Conference Room. The Exhibit Hall provided a location where pipeline pigging service providers and pig manufacturers were able to display their technologies during each of the two one-day events.

Shannon & Wilson was responsible for providing facility planning, conference organization, and documenting conference proceedings. Ms. Karen Zac, a conference event planner with Visions Meeting and Event Management, assisted in organizing the Conferences and Exhibit Halls. This report documents the information presented at the technical sessions and at the exhibitor booths during the 2006 Maintenance and Intelligent Pigging of Pipelines Conferences.

2.0 CONFERENCE CATEGORY DESCRIPTIONS

The subject technologies addressed by the two conferences involve equipment and methods to clean and inspect the interiors of oil and gas pipelines on the North Slope of Alaska. Maintenance and intelligent pigging were identified as the two topics desired for these pipeline integrity conferences.

2.1 Maintenance Pigging

There are three general reasons to use maintenance pigs to clean active pipelines: improving pipeline flow efficiency, improving data collection on inspection tool runs, and improving the results of chemical programs to inhibit corrosion and increase pipeline lifespan.

Maintenance, or cleaning, pigs are designed to push loose material through the pipeline and to apply a mechanical force between the pig and the pipeline wall to remove debris that can be easily removed. The material type used to construct the pig, as well as the hardness and thickness of deposits on the pipeline wall, will affect the ability of the pig to perform as designed. An effective seal must be maintained between the pig and the inside wall of the pipeline to maximize the cleaning effectiveness. Maintenance pigs are typically constructed using a combination of discs, cups, or foam, with mounted brushes of various materials. A Standard Scraper Pig is illustrated in Figure 1.

Debris encountered inside the pipelines may include wax, sand, corrosion by-products, carbonate scale, and/or water. This debris must be pushed ahead of the pig to the receiving unit without getting stuck. Increased pigging frequency is necessary where debris accumulates rapidly in the pipeline during normal operations. There are no industry standards for the frequency of maintenance pigging, or for measuring the effectiveness of a maintenance pig run. The concentration and composition of total suspended solids, bacteria, and biocides in the pigging returns are examples of indicators used to the measure the effectiveness of a maintenance pig run.

Maintenance pigs are introduced into a pipeline through a pig launcher and retrieved from the pipeline via a pig receiver. A Pig Launcher and Receiver is depicted in Figure 1. An active transmission pipeline on the North Slope carries crude oil, natural gas, and produced water. Introducing a maintenance pig into the pipeline must consider that the pipeline pig launcher and receiver are pressurized vessels and may contain an explosive and hazardous atmosphere. Proper venting and inerting of the pig launchers and pig receivers are required prior to opening. Guidelines for designing pig launcher and receiver traps are shown in Figure 2.

A pipeline may be considered unpiggable when it has no launching and receiving facilities. Multiple diameter pipelines may also be considered unpiggable if pigs are not able to expand and contract to maintain contact with the inside wall of each pipeline segment. A good seal between the pig and the inside wall of the pipeline will maintain sufficient pressure behind the pig to propel the pig downstream. Low pressure and/or flow within a pipeline may also be a condition to consider a pipeline unpiggable. It may also be considered unpiggable based on the inability of a pig to navigate through a T-section, Y-section, tight or mitered bend, or valve restriction.

2.2 Intelligent Pigging

Intelligent pigs are used to perform in-line inspections of active pipelines for signs of metal loss, internal or external corrosion, or dents and gouges from physical damage. Several types of intelligent pigs are used for in-line inspection of pipelines, with different technologies having relative advantages and disadvantages in detecting defects. The specific application must be considered when designing an appropriate in-line inspection program. The main internal inspection technologies are magnetic flux leakage (MFL), ultrasonic technology (UT), and geometry/deformation/caliper tools.

Two types of magnetic flux tools are commonly used: a magnetic flux leakage tool and a transverse MFL/transverse flux inspection (TFI) tool. The MFL identifies and measures metal loss by inducing a magnetic flux along the axial length of the pipe wall. Sensors on the tool detect and measure the amount of flux leakage, which can be attributed to anomalies such as corrosion, gouges, or other forms of metal loss. A MFL inspection pig is depicted in Figure 3.

TFI tools use the same principle as MFL except that the magnetic field is oriented at a 90º rotation or circumferentially. The TFI tool is used to determine the location of longitudinally oriented cracks or corrosion, such as seam-related defects and other wall defects that are not detectable with conventional MFL tools.

Two types of ultrasonic tools are also commonly used for in-line pipeline inspections: compression wave ultrasonic testing and shear wave ultrasonic testing. Compression wave UT tools measure pipe wall thickness and metal loss with transducers that emit ultrasonic signals perpendicular to the pipeline surface. An echo received from the signal is used to determine wall thickness. Pipeline cleanliness is important for the effective use of UT tools. Shear wave UT tools can reliably detect longitudinal cracks, weld defects, and crack-like defects. It uses shear waves generated in the pipe wall by angled transmission of UT pulses through a liquid coupling medium such as oil or water. A UT inspection pig is depicted in Figure 3.

Geometry tools use mechanical arms to measure the pipeline bore. Geometry tools are used to identify dents, deformations, and other changes in the pipe circumference. These tools can be used to identify the orientation, location, and depth measurement of each dent or deformation. A geometry tool inspection pig is shown in Figure 4.

Excavations, known as digs, may be required to verify and confirm the type and extent of a metal loss or physical damage anomaly. The priority for conducting digs is determined based on the severity of the anomaly and consequences associated with pipeline failure.

Robotic or remote-controlled inspection tools have become available, or will be available in the near future, for pipelines that have not been designed for periodic in-line inspections. The Explorer remote-controlled inspection tool is depicted in Figure 4.

2.3 Pipeline Integrity Management Regulations and Standards

The Hazardous Liquids Integrity Management Program (IMP), outlined in 49 Code of Federal Register (CFR) Part 195 and promulgated by the U.S. DOT-Pipeline and Hazardous Materials Safety Administration (PHMSA)-Office of Pipeline Safety (OPS), establishes rules for pipeline integrity management in high consequence areas for hazardous liquid pipeline operators. These rules specify regulations to assess, evaluate, repair and validate, through comprehensive analysis, the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, unusually sensitive areas (drinking water or ecological resources) and commercially navigable waterways. Additional information regarding ILI requirements and standards can be found in:

- Managing System Integrity for Hazardous Liquid Pipelines, American Petroleum Institute (API) Standard 1160;
- In-line Inspection Systems Qualification Standard, First Edition, API Standard 1163;
- Standards of Pressure Piping, American Society of Mechanical Engineers (ASME) Publication B31;
- In-Line Nondestructive Inspection of Pipelines, National Association of Corrosion Engineers (NACE) TR 35100, Item No. 24211;
- Recommended Practice: In-Line Inspection of Pipelines, NACE Standard RP0102-2002, Item No. 21094;
- Pipeline Operator Forum. (2005). Specifications and Requirements for Intelligent Pig Inspection of Pipelines. Version 3.2. January 2005; and
- Observations on the Application of Smart Pigging on Transmission Pipelines: A Focus on OPS's Inline Inspection Public Meeting of 8/11/05. September 5, 2005 for the Pipeline Safety Trust.

3.0 MAINTENANCE PIGGING TECHNOLOGIES

The Maintenance Pigging Conference began with opening remarks by representatives of ADEC, BP, and CPAI. Larry Dietrick, Director of ADEC's Division of Spill Prevention and Response, commented on the purpose of the conference, which was to gather information from experts in the field of pipeline maintenance pigging technology, examine how those technologies can be applied to Alaska's North Slope pipelines, and discuss the best technologies and practices that may be employed in Arctic oil pipelines.

Maureen Johnson, BP Vice-President for Greater Prudhoe Bay, provided an update on Prudhoe Bay operations over the past year, including their response efforts to the oil transit line leaks during that time. Gorg Storaker, Vice-President of North Slope Operations and Development for CPAI, provided brief comments on the objectives and expectations for the Maintenance Pigging Conference.

Tom McCloskey moderated the Conference and introduced the speakers, presenters, and the Industry and Regulatory Panel members. The Industry and Regulatory Panel for the October 19, 2006 Maintenance Pigging Conference was comprised of the following individuals:

1. Bill Hedges — BP, Manager of Corrosion Strategy and Planning
2. Jim Lagomarsino — BP, Oil Transport Pipeline Assurance Manager
3. Mark Peterson — BP, North Slope Pigging Operator
4. Steve Sauer — BP, Mardi Gras Commissioning Manager
5. David Newman — CPAI, Corrosion Engineer, Chemicals and Monitoring
6. Bob Bray — CPAI, Operations Support Manager, North Slope Operations and Development
7. Chuck Knecht — CPAI, Pipeline Operations Supervisor
8. Sara Pate — CPAI, Pipeline Engineer
9. Sam Saengsudham — ADEC, Pipeline Integrity Section Manager
10. Dave Hart — Pioneer, Senior Staff Facility Engineer
11. Louis Kozisek — ADNR State Pipeline Coordinator's Office, Chief Engineer
12. Cathy Foerster — Alaska Oil and Gas Conservation Commission (AOGCC), Commissioner
13. Tom Johnson — BLM Joint Pipeline Office, Corrosion Engineer
14. Bill Flanders — U.S. DOT-PHMSA-OPS, Engineer.

Four maintenance pigging presentations were delivered during the October 19, 2006 Maintenance Pigging Conference. The conference was videotaped and audio taped for purposes of developing transcripts of the presentations and Q&A sessions. Each of the presentations is summarized below. In addition, abstracts and transcripts of the presentations and Q&A sessions are included as appendices and are referenced in the following sections. Supplemental information such as complete presentation reports, photographs and/or diagrams provided by the individual presenters is also included in the referenced appendices. Video recording tapes and DVDs of the conference presentations, Q&A sessions, and Exhibit Hall were provided to the Steering Committee.

3.1 Presentation 1: Utility Pigs and Applications to North Slope Pipelines

Mr. Gary Smith, President of Inline Services, presented a discussion of the use of maintenance pigs in the commissioning and maintenance of oil and gas pipelines. The abstract and transcripts corresponding to this presentation are included in Appendix A.

The basic requirements of a pipeline for transporting liquids and gasses are: it has to be continuously operated; the throughput has to be maximized with the least amount of operating cost; and the integrity of the pipe must be maintained. During pipeline operation, debris such as wax, sand, corrosion by-products, scale, and liquid condensate can accumulate, affecting the ability of the pipeline to meet those requirements. In addition, corrosion can occur to the pipeline wall, affecting the pipeline integrity.

Maintenance pigs are used to remove debris, clean pipeline walls, and apply corrosion inhibitors. Debris removal pigs are designed based on the type of debris and deposits they are intended to remove. They may include disk pigs of varying configurations, scraper cup pigs, and foam pigs, generally designed to entrain debris and deposits into the pipeline flow for removal at the pig receiver. Different types of maintenance pigs are illustrated in Figure 1 and in the vendor brochures in Appendix E.

Progressive pigging is used for pipelines with an unknown volume of material inside or pipelines which have not been cleaned recently. Several soft urethane foam pigs can be used initially to ensure there are no in-line obstructions or large volumes of sediment, wax, or debris. Different pig types with increasing hardness and aggressiveness are then used to gradually move accumulated material out of the pipeline. The more aggressive pigs apply greater force perpendicular to the pipeline wall and are equipped with a combination of cups, disks, and brushes. Modifications to pig designs often include the use of leaf-spring brushes for scouring the pipeline walls to remove hard deposits or scale. A slotted hard disk is used to cut wax and dislodge it from the pipe wall. Tensile brushes are used to thoroughly clean corrosion pits and prepare the pipeline walls prior to applying corrosion inhibitors and performing an in-line inspection.

3.2 Presentation 2: Greater Kuparuk Area Field Pipeline Maintenance Pigging

David Newman, a corrosion engineer with CPAI, presented a discussion on the use of cleaning pigs for routine maintenance of pipelines in the Greater Kuparuk Field on Alaska's North Slope. The abstract and transcripts corresponding to this presentation are included in Appendix B. In addition, a copy of the power point presentation *Greater Kuparuk Area Field Pipeline Maintenance Pigging* provided by Mr. Newman is included in Appendix B.

The Kuparuk Area includes the Kuparuk, Karn, Melt Water, Tabasco, and Palm oil fields. The Kuparuk Field is comprised of 47 drill sites and over 1,100 wells. These wells are connected by a network of 530 miles of insulated pipeline. These service pipelines can be broken down into five different types:

1. Production lines that carry oil, water, and gas (three-phase flow) from the drill sites to the central production facilities (CPFs);
2. Wet oil lines that carry production liquids following the first stage gas separation at CPF3 to CPF1 and CPF2;
3. Water injection lines that carry produced water and seawater from the CPFs for injection at the drill sites;
4. Seawater pipelines that distribute seawater from the seawater treatment plant to the CPFs; and
5. Common carrier lines that transport crude oil from the Alpine Field and Milne Point to the CPFs and then to the Trans Alaska Pipeline.

Pipeline pigging frequencies and pig types are based on the type of line, field and industry experience, and the type of fluids that are handled in each line. Performance indicators such as total solids removed, the composition of those solids, bacterial activity, and biocide residuals are monitored and evaluated as a means to track the effectiveness of the pigging program and to determine subsequent pigging frequencies.

Over 120 maintenance pig runs are performed each month as part of the CPAI pipeline integrity monitoring program. The information obtained from each pigging run is input into a database to track pigging activities throughout their area of operation.

3.3 Presentation 3: Tools and Techniques Used to Clean Pipelines

Derek Clark, Business Development Manager, USA and Latin America Region, for BJ Process and Pipeline Services Company, focused his discussion on cleaning pipelines which have been in service but have not been subjected to a regular maintenance pigging regime. The abstract and transcripts corresponding to this presentation are included in Appendix C. In addition, the technical paper regarding *Recent and Near Future Advances in Maintenance Pigging Tools and Techniques Used to Clean Pipelines* by Mr. Clark is included in Appendix C.

Three general categories of information were discussed in context of developing an appropriate pigging program for these types of pipelines. BJ's engineers and scientists need to know: (1) the conditions and parameters associated with the pipeline; (2) the type and volume of material to be removed; and (3) the reason for cleaning and/or the level of cleanliness desired.

Both internal and external pipeline conditions relevant to the cleaning operations need to be known before designing a cleaning program. Internal parameters include the pipeline's diameter and length, potential in-line obstructions, maximum allowable operating pressure (MAOP), etc. and whether there are launcher and receiver facilities. Some important external parameters that need to be known include location, topography, temperature, and material disposal options.

The type and volume of material to be removed may be the most critical information in determining the scope of a pipeline cleaning program. A sample of the materials to be removed, preferably with a cut-out section of the actual pipe, must be obtained to determine the appropriate pig design as well as the need for chemical solutions to enhance cleaning efforts.

There are three basic reasons for pipeline cleaning: preparing for an in-line inspection run; efficiency gains; and removing hazardous and/or corrosive material and/or by-products. The required level of cleanliness may vary within these three categories. For example, the required level of cleanliness is higher for UT than for MFL tools. Measuring the level of cleanliness following maintenance pigging is usually subjective and based on the purpose of the cleaning program. International standards for pipeline cleanliness are not used in the industry and to Mr. Clark's knowledge do not exist. Caliper tools equipped with very soft springs allowing the sensor arms to deflect have been used to measure the thickness of the deposition along the length of the pipeline.

Four basic cleaning techniques were discussed in this presentation: mechanical, chemical, gel cleaning, and other potential techniques. Mechanical cleaning is accomplished using pigs to scrape and push accumulated debris from the pipeline. Chemical treatment for scale buildup and other deposits is typically applied as slugs between batching pigs. Solvents may be used to dissolve organic material, breaking up these deposits to make mechanical pigging operations more effective. Reactive chemistry is a general term to describe chemicals that react with the scale or deposit and is used on inorganic scales or corrosion by-products. Surfactants can be described as soaps that form a solution, particularly with light end hydrocarbons, to facilitate their removal.

Cleaning gels are highly viscous liquids that can be applied to increase the efficiency of the cleaning process. The application of debris pickup gels ensures that the debris remains suspended, even if the gel is static for an extended period of time, and assists in the transportation of unwanted materials out of the pipeline. Paraffin solvent gel penetrates and breaks paraffin deposition from the pipeline wall then behaves in a manner similar to debris pickup gels.

Mr. Clark emphasized that the problem with cleaning unpiggable pipelines should be resolved instead of looking for a cleaning solution without fixing the problem. For example, if the pipeline is not piggable because it does not have pig launchers and receivers, the pipeline should be equipped with these. It is possible to access the inside of the pipeline with special tools to dislodge the debris from the pipe walls. This debris, however, will eventually need to be removed with a pig.

3.4 Presentation 4: Latest Technology in Pig Designs

Becky Libby, Sales Manager with Enduro PLS, presented a discussion on the latest developments in pigging designs. The abstract and transcripts corresponding to her presentation are included in Appendix D.

This presentation focused on the use of new pig applications to enable pigging of pipelines once considered unpiggable. Characteristics of pipelines in this category include multi-diameter piping, short mitered bends, and undersized valves. In general, pig design has not changed much in recent years. While the components have not changed, their application has been expanded to include previously unpiggable pipelines.

Cleaning pigs for multiple diameter pipelines are available and can be manufactured to pig lines with changes of up to 1.5 diameters (eg., 28-inch to 42-inch). Ms. Libby recommends that all mitered bends be removed prior to pigging. Cleaning pigs, however, can be designed to traverse mitered bends if the radius of the bend is large enough to allow the pig to pass through. Pigs passing through tight or mitered bends lose their seal or contact with the inner pipe wall and can become stuck. To overcome this restriction, pigs can be built to have longer bodies with disks at both ends, have smaller diameter bodies, and/or multiple sections connected with U-joint assemblies. The rear disk needs to maintain its seal and push the pig through the tight or mitered bend until the front disk regains its seal and pulls the pig completely through.

Pipelines with undersized valves can be pigged, with pig designs depending on the internal diameter change between the pipeline and valve. Pigs with dual diameter sealing components or conical shaped pigs may be applicable. The larger disks or cups on the dual diameter pig open up to seal within the larger diameter portion of the pipeline segment and fold back down when entering the smaller diameter portion of the pipeline segment.

Pigs are sized according to the diameter of the pipeline. The outside diameter of the urethane cups or disks should be about 3 to 5 percent larger than the inside diameter of the pipeline. Anticipated future pig developments include improvements to single diameter pigs to increase their cleaning capabilities for in-line inspections. In particular, the manufactures are trying to advance the performance of the wire brush design to clean corrosion pitting.

3.5 Maintenance Pigging Exhibitors

Six exhibitors representing maintenance pigging product and service vendors attended the conference. The exhibitors included BJ Integrated Pipeline Services; Enduro Pipeline Services; Inline Services; Pipeline Engineering; Rosen; and TD Williamson. Following are brief summaries of the services provided by each exhibitor. In addition, informational brochures provided by the exhibitors are included in Appendix E.

- BJ Integrated Pipeline Services provide a broad range of services to pipeline operation companies, including methods to clean pipelines and customized engineering solutions.

- Enduro Pipeline Services designs and manufactures a variety of pig styles to address specific pipeline maintenance needs, which are determined by the desired application and pipeline configuration.

- Inline Services Inc. is a manufacturer and supplier of pigging equipment to the pipeline and process industries. Their Pipeline Cleaners Inc. (PLC) division designs and manufacturers heavy-duty ring, strip and block brushes for aggressive cleaning of deposits, specialty brushes for cleaning pits caused by corrosion, and tensile brushes used on electromagnetic inspection pigs.

- Pipeline Engineering offer a combination of consulting services, CAD design technology, advanced production processes, test facilities, comprehensive project management and deployment services. Their capabilities include manufacturing foam, metal bodied (mandrel) and solid polyurethane pigs, and pig launchers and receivers, as well as engineering and field services to develop and test pipeline cleaning programs.

- Rosen pipeline cleaning tools are designed to remove any kind of pollution, whether heavy debris, black powder, paraffin or scale deposits. Rosen offers standard disc and cup-type cleaning tools and special configurations to address progressive removal of wax and scale, product removal with nitrogen, dual-diameter pipelines, and gate valves.

- TDW Offshore Services specializes in developing pigs that can handle multiple pipeline induced pigging challenges combined with requested functionality. These challenges include varying pipeline diameters, restricted valve borings, varying pipeline temperatures, long Y-pieces, T-pieces, tight bends, and launching/receiving limitations.

3.6 Maintenance Pigging Conference Evaluator Comments

Thirty-two completed evaluation forms were received from the approximately 185 individuals, not including organization staff, who attended the Maintenance Pigging Conference. Overall, 77% of the evaluators rated the conference good (52%) to excellent (25%). For future conferences, the evaluators suggested that the following topics be included:

- Pig launchers/receivers and propulsion of pigs through pipelines;
- Three-phase fluids;
- Regulatory issues;
- Criteria for choosing configuration of pigs;
- Corrosion monitoring;
- Microbiologically influenced corrosion;
- How reservoir depletion, production, and pipeline design affects pipeline pigging programs; and
- More technology transfer.

Following the Maintenance Pigging Conference, the pipeline integrity conference Steering Committee requested that presenters for the November 13th Conference incorporate the above suggested topics into their presentations. In addition, the February 12 through 14, 2007 NACE Conference in Anchorage incorporated corrosion monitoring and microbiologically influenced corrosion as topics for presentations and continued the series of pipeline integrity conferences.

4.0 INTELLIGENT PIGGING TECHNOLOGIES

The Intelligent Pigging Conference began with opening remarks by representatives of ADEC, BP, and CPAI. Larry Dietrick, Director of ADEC's Division of Spill Prevention and Response, commented on the purpose of the conference, offered a brief recap of the October maintenance pigging conference and participant feedback, and emphasized the continuing potential for oil recovery on the North Slope.

Sandy Stash, BP Vice-President for Regulatory Affairs and Compliance, provided a discussion of several initiatives BP is undertaking to improve performance of their pipeline management systems. BP anticipates a continuing presence on the North Slope of Alaska and has programs geared toward renewal of their infrastructure there. They have also undertaken internal organizational changes with the creation of a technical authority to provide a standard-setting body within BP and to provide additional checks and balances for their facility operations. BP has also partnered with the DOT to put 122 miles of pipeline on the North Slope under the DOT integrity management program.

Paul Dubuisson, of CPAI, welcomed the conference participants and presenters, and provided brief comments on the objectives and expectations for the Intelligent Pigging Conference.

Tom McCloskey moderated the Conference and introduced the speakers, presenters, and the Industry and Regulatory Panel members. The Industry and Regulatory Panel for the November 13, 2006 Intelligent Pigging Conference was comprised of the following eight individuals:

1.	Greg Swank	BP, Manager of Regulatory and Technical Services
2.	Chris Dash	CPAI, Corrosion Engineer
3.	Sam Saengsudham	ADEC, Pipeline Integrity Section Manager
4.	Dan Cutting	Pioneer, Senior Facility Engineer
5.	Louis Kozisek	ADNR State Pipeline Coordinator's Office, Chief Engineer
6.	Tom Maunder	AOGCC, Senior Petroleum Engineer
7.	Tom Johnson	BLM Joint Pipeline Office, Corrosion Engineer
8.	Bill Flanders	US DOT-PHMSA-OPS, Engineer.

Six intelligent pigging presentations were delivered during the November 13, 2006 conference. The conference was videotaped and audio taped for purposes of developing transcripts of the presentations and Q&A sessions. Each of the presentations is summarized below. In addition, abstracts and transcripts of the presentations and Q&A sessions are included as appendices. Supplemental information such as complete presentation reports, photographs and/or diagrams provided by the individual presenters is also included in the referenced appendices. Video recording tapes and DVDs of the conference presentations, Q&A sessions, and Exhibit Hall were provided to the Steering Committee.

4.1 Presentation 1: Inline Inspection Using Magnetic Flux Leakage Technology

Frank Sander, a Non-Destructive Testing Research Analyst with BJ Pipeline Inspection Services (BJ), provided a brief description of the different types and functions of MFL tools. The abstract and transcripts corresponding to his presentation are included in Appendix F. In addition, a copy of the power point presentation *Inline Inspection Using Magnetic Flux Leakage Technology* was provided by Mr. Sander and is included in Appendix F.

This presentation began with a description of MFL technology, followed by a discussion of how to evaluate the success of a pigging run, types of anomalies that can be detected by MFL, current uses of the MFL technology, and how BJ presents the results of an in-line inspection run.

Three technology types were discussed – MFL, transverse MFL, and high-resolution MFL. While each method employs the same basic technology, they differ in the methods of pipe magnetization and anomaly measurement. MFL magnetizes the pipe in the axial direction and measures anomalies along the pipe circumference. Transverse MFL magnetizes the pipe circumferentially and measures anomalies in the axial direction parallel to the pipe's length. High-resolution MFL in-line inspection pigs have increased sensor density and sampling frequency and may be equipped with tri-axial sensors to detect magnetic flux leakage in the axial, radial and circumferential directions.

The success of a pigging run is measured by the ability of the pig to safely complete its passage through the pipeline and to properly collect the desired data. The ability of a pig to complete its run is affected by mechanical features such as bore diameter, bend radius, and flow velocity. These parameters are functions of the pipeline rather than the pig itself. MFL pigs have tool drag, resulting from friction forces of cups and brushes riding against the pipeline wall, as well as magnetic forces. Insufficient pressure in the pipeline can cause the pig to slow or stop, followed by a pressure buildup and resulting high velocity travel. This can result in inadequate data collection as well as damage to the pig.

The MFL tools are designed to detect both internal and external metal loss due to corrosion. Transverse MFL is also used to detect thin axial cracks or crack-like defects. Both tools can detect deformations such as dents, wrinkles, laminations, occlusions, and weld-related anomalies. Once collected, this information is interpreted and reported to the client.

While the MFL technology has always been used to detect dents, current developments are being used to size the depth of the dent, and to determine if there is a stress concentrator within the dent such as cracks, corrosion, gouging, etc. The MFL inspection pigs also have inertial navigation systems to map out the pig's progress through the pipeline and obtain GPS coordinates of anomalies and above ground markers.

A BJ inspection report represents the conditions of the pipeline at the time of the run. The pipeline operator may be given the viewing software to view all the defects detected in the line. Technical support for the software and for viewing the defects is also available.

4.2 Presentation 2: Ultrasonic Tools in Pipeline Inspection

Jon Wharf, Analysis Technical Leader with GE PII, presented a discussion of the use and function of Ultrasonic Technology (UT) for in-line inspection of oil and gas pipelines. The abstract and transcripts corresponding to this presentation are included in Appendix G. In addition, a copy of the power point presentation *Ultrasonic Tools in Pipeline Inspection – A Review of the Technology* was provided by Mr. Wharf and is included in Appendix G.

Mr. Wharf's presentation began with a brief description of ultrasound technology, followed by a discussion of data analysis and interpretation and strengths of UT tools and inspections. Within the range of ultrasound technologies, there are two basic liquid-coupled approaches: wall thickness measurement methods and crack detection methods. Liquid-coupled UT technology relies on a single liquid phase product in the pipeline. Three-phase pipelines, containing oil, water, and gas, can be inspected with liquid-coupled UT technology if the mix of liquids is fairly consistent. Two uncoupled, non-liquid technologies, Elastic Wave and Electro Magnetic Acoustic Transducer (EMAT), are used for crack detection.

The wall thickness measurement method uses product in the pipeline to inject the ultrasound from the tool perpendicularly into the pipe wall. The UT tool fires an ultrasound pulse through the medium into the pipe wall then looks for two echoes. The first echo is from the ultrasound meeting the inner pipe wall and the second echo represents the ultrasound hitting the outer pipe wall. This process generates data on wall thickness through the pipeline and can identify anomalous areas. Crack detection is accomplished using similar liquid-coupled methods, though the ultrasound pulses are fired at an angle to the pipe wall in both clockwise and counterclockwise fashion. As the ultrasound pulse passes along the inside pipe wall it hits obstructions such as cracks or other reflectors, then bounces back to the sensor to be collected and analyzed. UT tools are being developed that combine both the wall thickness and crack detection methods.

Elastic wave uses fluid-filled wheels in contact with the inner pipe wall. Ultrasound waves are injected into the pipe wall at an angle and are reflected by pipe features such as laminations and cracks. The echo is detected by the sensor probes mounted in the fluid-filled wheels. The EMAT system delivers electro-magnetic waves to the pipeline which produce sound directly in the steel. The ultrasonic signal generated by the steel is then detected by sensors. The EMAT system is a crack detection and wall thickness measurement tool.

Pipeline characteristics that need to be considered prior to running UT tools are similar to those described for MFL inspections (e.g., bore diameter, bend radius, flow velocity, etc.). Pipeline cleanliness is a major consideration, as material buildup on the pipe wall can interfere with UT transmissions. UT tools can perform through minor accumulations of smooth scale or hard wax. However, soft wax or deposits tend to soak up the ultrasound pulses and prevent effective inspections. Multiple cleaning runs are often required to reach inspection conditions.

Reporting of UT runs is similar to MFL. UT reports include illustrations of features such as general corrosion, channeling/grooving corrosion, narrow axial external corrosion, pitting corrosion, gouging, cracks, dents, and manufacturing-related wall thickness variations.

4.3 Presentation 3: Geometry and Deformation/Caliper Tools

Pat Vieth, Senior Vice President for Integrity and Materials with CC Technologies, Inc., presented a description of Geometry and Deformation/Caliper Tools. The abstract and transcripts corresponding to this presentation are included in Appendix H. In addition, a copy of the power point presentation *Geometry and Deformation/Caliper Tools* was provided by Mr. Vieth and is included in Appendix H.

The presentation summarized the integrity threats to pipelines that can be addressed through the use of deformation and caliper tools; described tool design, capabilities, and limitations; and discussed the application of survey results. The focus of the integrity threats was on mechanical damage, dents, wrinkles, and buckles. Mechanical damage is often the result of construction or excavation activities hitting pipelines. This type of damage can result in dents or cracks in the pipeline wall. Dents can be described as either constrained or unconstrained. Constrained dents are commonly on the pipe bottom, where the pipe sits on some object such as a rock. Unconstrained dents are typically found on the top of the pipe, and could be the result of a pipe manufacturing defect or mechanical damage. Field bends were once used in pipeline construction, resulting in wrinkle bends. Pipeline buckling is seen due to pipe displacement or subsidence.

A number of tool designs were described, from manufacturers including TD Williamson Magpie, BJ Pipeline Services, Tuboscope, and Rosen. Geometry, deformation, and caliper tools have sensors mounted within cups, paddles or wheels that contact the inner wall of the pipeline. The sensors are tightly spaced, about one to two-inch spacing, around the pipe circumference. The cantilever-supported sensor rides over the deformation and measures the maximum deflection of geometric changes in the pipeline.

4.4 Presentation 4: Regulatory Requirements and Standards for Smart Pigging

Jon Strawn, Senior Engineer/Project Manager, Alaska District represents the U.S. DOT-PHMSA-OPS. Mr. Strawn presented a discussion of the regulatory environment surrounding the operation and maintenance of hazardous liquid pipeline segments. The abstract and transcripts corresponding to this presentation are included in Appendix I.

The integrity management program administered by DOT (49 CFR 195.452) goes beyond pigging technologies and in-line inspection programs. Its focus is on managing the integrity of pipelines in high consequence areas. A high consequence area is defined as a high population area (>50,000 people), other populated area (>25 people), an unusually sensitive area (drinking water and/or ecological resources), or a commercially navigable waterway. Only pipeline segments of oil transmission lines operating at greater than 20% specified minimum yield strength (SMYS) are currently regulated under the integrity management program. The four goals of the integrity management rule are:

1. To accelerate the integrity assessments of pipelines in high consequence areas;
2. To improve integrity management systems within operating companies;
3. To improve the government's role in reviewing the adequacy of the integrity programs and plans; and
4. To increase public assurance in pipeline safety.

An integrity management program includes: (1) identification of pipeline segments that could affect high consequence areas; (2) establishment of a baseline assessment schedule based on risk factors; (3) baseline assessment(s); and (4) continual or on-going integrity assessment. The baseline assessment can be performed using in-line inspection techniques, pressure testing, or other technologies.

An operator must take action to address all anomalous conditions discovered through the baseline assessment, addressing the highest risk segments first. The timeframe in which an operator has to conduct repair activities is dependent upon the severity of the identified condition. The identified conditions from a pigging inspection are classified into three types: immediate repair; repair within 60 days; and repair within 180 days. An example of an immediate repair would be for the discovery of metal loss of greater than 80 percent of the pipe wall thickness. The timing and method for subsequent assessments are determined based on risk analyses but, at a minimum, must be conducted within 5 years following the baseline assessment. Jon indicated that DOT statistics show that pipeline operators use high-resolution MFL most often to assess the integrity of their pipelines.

4.5 Presentation 5: Pigging the Unpiggable

Mark Olson, President and CEO of Trinity Pipeline Assessments, LLC, presented a discussion of the varying degrees of unpiggable pipelines and recent and near future advances in pigging tools used to inspect unpiggable pipelines. The abstract and transcripts corresponding to his presentation are included in Appendix J.

The term "unpiggable" is not well defined; the presentation began by exploring that term. Is a pipeline unpiggable because it has never been pigged before, or it has no launching and receiving facilities, or multiple diameter changes, low pressure, or is the pipeline constrained by features that tools can't navigate?

The presentation approach emphasized that in-line inspection techniques can be developed for almost any combination of unpiggable pipelines. A limited discussion was presented on multiple diameter pipelines due to the prevalence of inspection companies capable of managing that type of pipeline. Pipelines with no launching and receiving facilities may require that the inspection be performed off-line. The lack of flow in an off-line inspection requires alternative locomotion methods, such as aero-nitrogen pressure, cable-tethering, or remote-controlled robotic movement. Another possibility for pipelines without launching facilities or with in-line obstructions is to deploy and capture the pig by attaching a portable launcher/receiver to an access point on the pipeline such as a valve or flange or through hot tap fittings. Pipelines with mitered bends or in-line obstructions can be inspected from both ends of the segment to be pigged using similar access points. Mark showed a film featuring a remote-controlled inspection tool, the Explorer, which uses video observations to navigate and inspect the pipeline. Explorer II also uses video observations to navigate complex pipeline systems but is equipped with high–resolution MFL and geometry/deformation/caliper tools for performing off-line inspections.

4.6 Presentation 6: In-Line Inspection on the North Slope

Greg Swank of BP provided an overview of a comprehensive Integrity Management Program (IMP) for BP's North Slope operations. The abstract and transcripts corresponding to this presentation are included in Appendix K.

Greg began his presentation with a review of progress related to the DOT-regulated oil transit lines in Prudhoe Bay. In-line inspection tools were run on the Lisburne pipeline and two 34-inch pipelines in the eastern operating area and western operating area. The Lisburne line inspection found no anomalies, suggesting that no repairs are required on that segment of pipeline. Results of inspections on the other two lines were being evaluated and were not available as of the conference date.

Integrity management was described as a continuous improvement process applied throughout the design, construction, maintenance, and operation of pipelines. BP currently maintains separate integrity management programs for each of its regional divisions but is in the process of integrating them into a single program. A description of the integrity management program plan covered similar topics to those presented by Jon Strawn of DOT and mostly emphasized the risk management strategies of BP's program.

A qualitative risk assessment approach is used to evaluate the information collected during the baseline assessment. Key risk factors to consider are the proximity to high consequence areas, the type of product within the pipeline, fate and transport analyses, leak history, pipeline operating stress versus design limits, natural hazards, and pipe safety design. Managing data from different sources can be problematic when it is collected and stored in different forms, formats, and locations. The Pipeline Open Data Standard (PODS) system is relied upon for storing specific data from each pipeline segment. The information from the PODS is used to produce a Geographical Information System (GIS) overlay and relative risk scores for individual pipeline segments. Relative risk scores and the consequences related to those risks for each pipeline segment are used to develop risk mitigation and repair plans, as necessary. The methods and data utilized to generate the relative risk scores are continuously reviewed and updated to establish the frequency of subsequent pipeline integrity assessments.

4.7 Intelligent Pigging Exhibitors

Twelve exhibitors representing intelligent pigging product and service vendors attended the conference. Following are brief summaries of the services provided by each exhibitor. In addition, informational brochures provided by the exhibitors for the conference are included in Appendix L. The information provided by BJ Process and Pipeline Services and TDW Offshore is presented in Appendix E.

- A. Hak Industrial Services designed the ultrasonic Piglet system, an intelligent versatile tethered pig which is attached to a fiber optic "umbilical" to inspect the interiors of non-standard piggable pipelines.

- Baker Hughes PMG offers a variety of pipeline inspection tools. The CPIG™ line of high resolution MFL in-line inspection tools and experienced staff of intelligent pigging experts provide the pipeline industry with advanced and cost effective in-line inspection services.

- BJ Process and Pipeline Services (PPS) offer a wide range of services to the oil and gas pipeline industry. These services are designed to provide specific solutions to pipeline construction, installation, and operating companies, and include designing and implementing intelligent pigging programs.

- BJ Pipeline Inspection Services' products include the GEOPIG, a mechanical caliper tool used to assess pipeline curvature strain, dents, wrinkles, buckles, and other in-line features.

- GE Pipeline Solutions offer intelligent pig inspection products and services including MFL, ultrasound, and shear-wave inspection techniques for pipeline crack detection, seam weld defects, axial flaws, and third party damage.

- NACE International is a membership trade organization for the corrosion engineering and science community. They serve members by: setting standards for the corrosion industry; disseminating the latest technology worldwide through peer-reviewed journals and technical papers; hosting and managing the most important international conferences, exhibits and topical meetings in the corrosion industry; recognizing distinguished achievement in corrosion through the presentation of well-respected awards; and promoting the interests of the corrosion science and engineering industry through government relation activities in Washington, D.C.

- NDT Systems and Services AG provide a full range of pipeline inspection services using a range of in-line inspection tools based on ultrasound technology. Applications of NDT tools include inspections for wall thickness, metal loss, laminations and mid-wall flaws, pitting, cracks, corrosion, and cracking.

- ROSEN provides a range of high-resolution in-line inspection tools to evaluate pipeline geometry, corrosion, crack and coating detection, leak detection, and optical inspection of pipelines. The ROSEN Electronic Geometry Tools were designed to check pipeline construction quality, to locate undetected third-party damage, and to confirm free passage for other tools.

- Enduro Pipeline Services provides in-line inspection services using MFL technology to conduct metal loss, deformation, and inertial surveys, and geometry inspection using caliper survey equipment to log pipeline anomalies.

- Smart Pipe offers a pipeline liner designed to restore a pipeline to its full pressure service rating and renew the projected service life of the pipeline to like-new or better-than-new condition. Pipeline restoration is performed without diminishing the flow rates through the line despite the nominal reduction in inside diameter of the pipeline that occurs due to the presence of the liner.

- TDW Offshore engineers, fabricates and tests pipeline pigs to solve multiple pigging challenges for their customers. TDW Offshore has a line of products ranging from receivers, launchers and pig tracking products to pig handling equipment.

- Tuboscope Pipeline Services is a global pipeline inspection company, with a record of more than 650,000 miles of pipeline inspections worldwide. Tuboscope provides data acquisition tools, analysis, and visualization technology.

4.8 Intelligent Pigging Conference Evaluator Comments

Of the approximately 238 individuals who attended the Intelligent Pigging Conference, 45 completed evaluation forms were received. Overall, 87% of the evaluators rated the conference good (50%) to excellent (37%). Some of the evaluator suggested topics for future conferences include:

- Case studies on pipeline corrosion including: types, protective strategies and effectiveness, detection techniques, identification and avoidance under insulation, microbiologically influenced, and evaluation in excavations;
- Integrity management “holistic approach”;
- Comparison of integrity assessment methods including: in-line inspection, hydrostatic testing, and direct assessment specifications and performance;
- Data analysis and management;
- Examples of practical integrity assessment decision processes;
- Case studies on “impossible pigging” lines that were thought to be too difficult to pig, and how these issues were resolved; and
- Pipeline leak detection.

Many of the topics listed above were incorporated into related presentations at the NACE February 12, 13, and 14, 2007 pipeline integrity conference.

5.0 SUMMARY EVALUATION

The October and November, 2006 pipeline integrity conferences provided state-of-the-art information about maintenance and intelligent pigging technologies. World experts discussed the latest advances and best practices in maintenance and intelligent pigging and provided examples of how proven or promising technologies could be applied to Alaska's North Slope pipelines. Pipeline integrity management programs have been established by the two main North Slope pipeline operators, BP and CPAI, to continuously evaluate pipeline conditions and to prevent pipeline failure.

The pigging technologies and practices presented at the conferences may or may not be applicable for use on any given segment of pipeline. It is the task of the individual operators to determine how to incorporate the best pigging technologies and practices into their integrity management programs and into the design, operation, and maintenance of these Arctic pipelines.

5.1 Maintenance Pigging

Maintenance pigs are used to clean active pipelines to improve pipeline flow efficiency, remove undesirable material or debris such as wax, sand, corrosion by-products, carbonate scale, and water, and prepare the pipeline for an in-line inspection tool run. Both CPAI and BP have ongoing maintenance cleaning programs for pipelines they operate on the North Slope as part of their integrity management programs. There are no regulatory requirements to perform maintenance pigging, although maintenance pigging is a very important element of a successful pipeline integrity management program.

Only pipeline segments of oil transmission lines operating at greater than 20% specified minimum yield strength (SMYS) that could affect high consequence areas are currently regulated under the integrity management program administered by DOT (49 CFR 195.452). Low stress pipelines, such as an oil transit line operating at less than 20% SMYS, are currently exempt from DOT regulation. BP has agreed to include low stress pipelines into their integrity management program. The State of Alaska has proposed regulations requiring that about 1500 miles of flow lines on the North Slope, currently exempt from DOT regulation, be included into the BP and CPAI integrity management programs. DOT-OPS has also proposed regulations requiring that low stress oil transit lines on the North Slope, that are not currently regulated by DOT, be included in the integrity management programs.

The proposed regulations will affect pipeline segments that may not have been cleaned with a maintenance pig for many years. Increasingly corrosive fluids (i.e. increasing proportions of water and sediment) are being produced from the North Slope fields and are being transported by the pipeline system. CPAI, BP, and ADEC are committed to ensuring that these fluids are transported in a manner that prevents leaks and protects the environment. A baseline assessment will need to be performed for these new segments of pipeline that are to be included in the integrity management programs. The pipeline segments will need to be cleaned prior to performing the in-line inspection tool runs.

Information presented during the Maintenance Pigging Conference can be used to design a cleaning program for these new segments of pipeline. Critical design information includes pipe characteristics and the type and estimated volume of material to be removed. As discussed in the presentations, caliper tools and gamma ray scanning of above ground pipelines are techniques that can be used to develop estimates of debris quantities. Maintenance pigging experts also recommend obtaining a sample of the materials to be removed, preferably with a cut-out section of the actual pipe, to determine the appropriate pig design and evaluate the need for chemical solutions to enhance the mechanical cleaning efforts. North Slope operators currently use the concentration of total suspended solids in the pigging returns to determine the frequency of maintenance pigging.

Some of the new pipeline segments to be included in the integrity management programs may be unpiggable due to: the lack of launching and receiving facilities; low pressure and flow; or the pigs are unable to navigate through a tight or mitered bend or valve restriction. Best practices for preparing an unpiggable pipeline for an in-line inspection were also presented at the Maintenance Pigging Conference. Although it is possible to access the inside of the pipeline with special tools to dislodge debris from the pipe walls, it may not be possible to remove this debris without the use of a cleaning pig. Maintenance pigging experts at the conference recommended that under these circumstances, the pipelines should be equipped with pig launchers and receivers. Similarly, if cleaning pigs are unable to navigate through a tight or mitered bend or valve restriction, maintenance pigging experts recommend removal of the tight or mitered bends or valve restrictions to render the line piggable. Under low pressure and flow conditions, it may be possible to propel a cleaning pig from the launcher to the receiver using water, air or nitrogen gas.

5.2 Intelligent Pigging

The integrity management program administered by DOT (49 CFR 195.452) focuses on managing the integrity of pipelines in high consequence areas. A pipeline operator's integrity management program must identify which segments of their pipeline are in high consequence areas, and must entail a baseline assessment. Scheduling baseline assessments for the various pipeline segments is established based on risk factors.

BP's integrity management program utilizes a qualitative risk assessment approach to evaluate relative risk scores and the consequences related to those risks for each segment of pipeline. These relative risk scores are used to schedule baseline assessments, develop risk mitigation and repair plans, and establish the frequency for subsequent pipeline integrity assessments. The baseline assessment can be performed using in-line inspection techniques, pressure testing, or other technologies.

The main internal inspection pigging technologies use MFL, UT, and geometry/deformation/caliper tools. DOT statistics show that pipeline operators use high-resolution MFL most often to assess the integrity of their pipelines. MFL identifies and measures metal loss and detects cracks by inducing a magnetic flux at different orientations to the pipe wall. High-resolution MFL in-line inspection pigs have increased sensor density and sampling frequency and may be equipped with tri-axial sensors to detect magnetic flux leakage in the axial, radial and circumferential directions.

UT tools are very accurate and precise in-line inspection tools which use compression and shear waves to measure pipe wall thickness and metal loss and to detect longitudinal cracks, weld defects, and crack-like defects. The EMAT (Electro Magnetic Acoustic Transducer) system is a newer, highly-accurate crack detection and wall thickness measurement tool that is used in a non-liquid pipeline environment. Pipeline cleanliness is a major consideration for UT tools, as material buildup on the pipe wall, especially soft wax, can interfere with UT transmissions. In addition, UT tools operate best in a single-phase liquid line but can be batched in three-phase lines.

Geometry tools use cantilever-supported sensors to measure the pipeline bore and to identify dents, deformations, and other changes in the pipe circumference. In-line inspection pigs have inertial navigation systems to map out the pig’s progress through the pipeline and obtain GPS coordinate of anomalies and above ground markers.

Some of the pipeline characteristics that need to be considered prior to running MFL, UT, and geometry/deformation/caliper tools include bore diameter, bend radius, flow velocity, etc. In-line inspection techniques can also be developed for almost any combination of unpiggable pipelines. Explorer II is a remote-controlled inspection tool which uses video observations to navigate complex pipeline systems and is equipped with high–resolution MFL and geometry/deformation/caliper tools for performing off-line inspections. Prior to performing the in-line inspection tool runs, however, the pipeline segments will need to be cleaned. As discussed in the previous section, it may not be possible to adequately clean the pipeline for an in-line inspection tool run without the use of pig launchers and receivers and removal of tight or mitered bends or valve restrictions.

A pipeline operator must take action to address all anomalous conditions discovered through the baseline assessment, addressing the highest risk segments first. Excavations, known as digs, are used to verify and confirm the type and extent of a metal loss or physical damage anomaly. The priority for conducting digs and repairs is determined based on the severity of the anomaly and consequences associated with pipeline failure.

6.0 REFERENCES

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Enduro's Standard Scraper Pig - Standard Scraper Pigs are available in diameters ranging from 2-inch to 36-inch. It utilizes a heavy-duty cup which imparts extended wear life, good sealing ability, and excellent scraping action. The Standard Pig is equipped with four cups and can also be supplied with cleaning brushes and blades, gauging plates and magnets.

Pipeline Engineering's Pig Launcher and Receiver - The purpose of a pig launcher or receiver is to introduce or retrieve pigs, spheres or inspection tools into and from a pipeline. Launchers and receivers are built to suit the specific requirements of a pipeline and may consist of simple barrel launchers and receivers, to complete skid-mounted units that include actuated valves, instrumentation, pig signallers, and control systems.

2006 Maintenance and Intelligent Pigging Conferences Anchorage, Alaska	
CLEANING PIG AND PIG LAUNCHER/RECEIVER	
February 2007	32-1-17073
bp ConocoPhillips DEC	**Fig. 1**

PIG TRAP DESIGN GUIDANCE NOTES

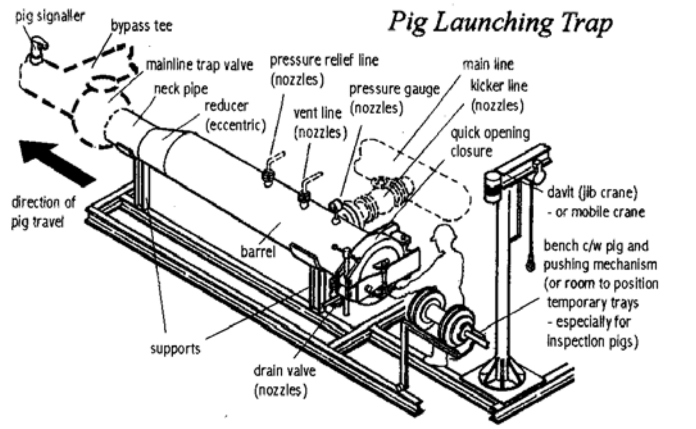
The main purpose of a pipeline pig trap system is to provide, in a safe manner - and without flow interruption - the means to both insert and launch a pig into a pipeline and receive and retrieve a pig from a pipeline.

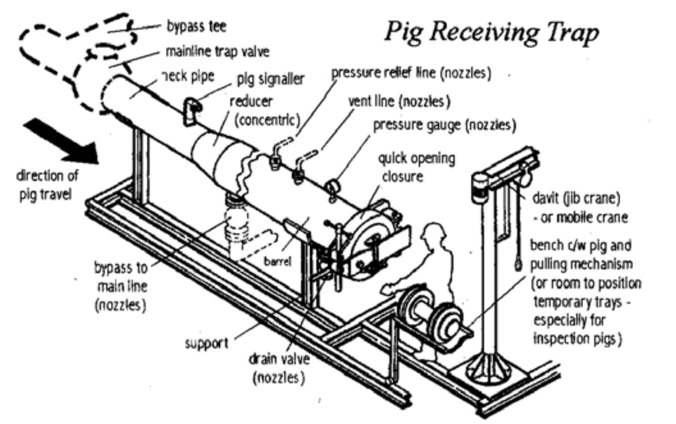
The essential difference between a launching and receiving trap is:

- **Overall length** - the receiver is longer
- **Position of bypass** - closer to the reducer on receivers
- **Location of pig signallers** - sited on the neck pipe of receivers

In pipelines where spheres are to be used, the traps have a small incline for launchers and a decline for receivers.

Minimum requirements with regard to design parameters, components and configurations are as shown in the table below:





		CONVENTIONAL PIGS		INSPECTION PIGS	
		LAUNCHER	RECEIVER	LAUNCHER	RECEIVER
BARREL	Diameter	2"> Neck pipe dia.		4"> Neck pipe dia.	
	Length	Neck pipe dia. x 4	Neck pipe dia. x 6	Tool length + 10%	Tool length + 10%
NECK	Length	≤24"ns: 500mm >24"ns: 1000mm		Tool length + 10%	Tool length + 10%
NOZZLES	Bypass	Neck pipe dia. x 25%		As Conventional Pigs	
Pipeline dia/nozzle dia Note: All diameters are	Vent	≤12"/1"; >12"/ ≥2"			
nominal size (ns)	Drain	≤12"/2"; >12"/ ≥4"			

DESIGN PARAMETERS to be considered:
Design code; Working pressure; Temperature; Testing & Inspection requirements; Welding requirements; Line product; Materials of manufacture; Type of pigs to be used; Paint finish

Important note! The above information is not intended to be a recommendation, but simply a guide to pig trap design. It will be applicable in some cases, but in many others, the design will have to be tailored to meet specific requirements. It is therefore essential that discussions are held with a PPSA member company before finalising any design.

Figure courtesy of Pigging Products and Services Association

2006 Maintenance and Intelligent Pigging Conferences
Anchorage, Alaska

PIG LAUNCHER AND RECEIVER TRAPS

February 2007 32-1-17073

bp ConocoPhillips

Fig. 2

BJ Services VECTRA Magnetic Flux Leakage (MFL) Tool. The VECTRA MFL tool utilizes an integrated gas bypass system with active speed control which allows all large diameter VECTRA tools to inspect a pipeline at optimum speed for high-resolution data collection while the pipeline maintains full product throughput rates. The VECTRA tool has a unique tri-axial sensor head configuration: circumferential, axial and radial. The addition of circumferential sensors is key to the accurate detection and characterization of metal loss, providing high-resolution length, width and depth information for internal and external metal loss defects. VECTRA's sensor configuration facilitates the detection and accurate sizing of long Narrow Axial Corrosion (NAC) features. A state-of-the-art inertial navigation system is also an integral part of the VECTRA tool design. Inertial mapping is used in combination with GPS reference points to accurately locate defects in the field, resulting in cost-effective dig programs.

GE Oil and Gas' UltraScan™ WM. Ultrasound Technology (UT) differs from MFL in its ability to deliver precise, direct measurements of pipeline features. UltraScan™ WM can detect and measure precisely mid-wall anomalies such as laminations and inclusions. To deliver its full potential, ultrasound must be coupled to the pipewall by a liquid medium. To inspect a dry pipeline, UltraScan™ WM is run in a liquid batch.

ROSEN Electronic Geometry Tool RoGeo. RoGeo possesses a fully computerized measuring system designed to inspect the internal geometry of pipelines. In addition to detailed information about geometrical features, such as bends, ovalities and dents, the geometry inspection also provides data about speed and temperature.

ExplorerTM represents the state-of-the-art in remote-controlled pipeline inspection systems. The battery-powered Explorer can perform long-range, extended duration visual inspections and can inspect thousands of feet of pipeline from a single excavation point. An operator controls Explorer through a wireless link and can monitor pipeline images in real time. Explorer II has high resolution MFL sensing sections and caliper sensors available.

APPENDIX A

MAINTENANCE PIGGING CONFERENCE PRESENTATION 1

UTILITY PIGS AND APPLICATIONS TO NORTH SLOPE PIPELINES

GARY SMITH OF INLINE SERVICES

ABSTRACT OF PRESENTATION 1

Utility Pigs and Applications to North Slope Pipelines

Speaker Name:	Gary Smith, President
Company Name:	Inline Services
Website URL:	www.inlineplc.com
Type of Business:	Manufacturer and supplier of pigging products for commissioning and maintenance of oil and gas pipelines

Pipelines are the most economical means to transport oil and gas, and one of the most valuable assets in the industry. Pigs are used in the maintenance of pipelines to maximize flow and minimize operating costs and, more importantly, to enhance chemical corrosion control efforts. Utility or cleaning pigs are commonly used during construction, maintenance and pre-inspection cleaning of pipelines. Proper selection of pig designs is a key element for a successful pigging program. Topics of discussion will include:

- Goals – using pigs to maximize efficiency and pipe integrity and to safeguard assets;
- Pigging Equipment Designs – Mandrel and foam pigs for sealing and cleaning;
- Conditions – application of pigs to control debris, remove liquids, separate products in onshore and offshore pipelines and pre-inspection cleaning;
- Corrosion prevention – minimize corrosion factors and prepare pipe for application of corrosion inhibitors;
- Operational benefits – reduce operating costs and extend operating life of pipelines;
- Limitations – due to lack of pig launching and receiving traps, tight bends, multi-diameter pipes, etc.

TRANSCRIPT OF PRESENTATION 1

The first presentation is by Gary Smith, who is making his way to the front of the room here. Gary is the President of Inline Services Pipeline Cleaners. Gary has 30 years of experience in the pigging industry. He has been involved primarily in maintenance of pipelines and pig manufacturing and teaches the section on pipeline maintenance at the annual pigging conference. Gary is familiar with the North Slope's pipeline layout and operating conditions at Kuparuk. In April 2006, Gary spent five days in Prudhoe Bay reviewing BP's anticipated cleaning procedures. Without further delay, here's Gary. Gary?

Gary Smith: Thank you. Can you hear me? Yes? First of all, I'd like to tell everybody that there is no way that we can--and I think I'm speaking for the other panel members in our industry as well as the vendors here--that we can teach you and tell you everything you need to do in several 45 minute sessions about pigging. So, please understand these are some overviews of this.

The next thing is that having been in the industry for so long I can assure you that pigging is something that nobody wants to do. It's messy, it's expensive and the trend in the industry is not to do it unless you absolutely have to. Several years ago we got kind of a resurgence in the industry because of regulations. People had to start inspecting pipelines. And there's where we really saw where some of the lack of maintenance was. You did not pig a pipeline unless you had too much wax or too much liquid in it. You really only did it for those reasons or unless you had to inspect. And now that we have to inspect as much as we do, it has become a major, major industry.

To begin with, there are two basic categories of pigs that we talked about. One of them is utility pigs. The other is the in-line inspection pigs. The in-line inspection pigs basically are any kinds of pigs that have electronics in it or tell you something once they come out of the pipeline. This is going to be discussed, I believe, at a future conference in November.

Today, I'm going to talk a little bit about cleaning pigs and what they do. There are three basic functions of cleaning pig. To clean the pipeline, to separate liquids or remove liquids, and to dewater pipelines of its condensate, produced water and so on. We call it the dumb side of the industry--the non-intelligent side.

There are several historic pictures of what pigs used to look like in case you are not that familiar with what pigs really are. Here are some pictures that were taken back in the 40's and 50's. It shows you a little bit about how pigs were developed over the years. The one that I just put up there actually has a leather disk on it as opposed to urethane and neoprene cups. This is a homemade pig from a contractor. It shows some blades on springs which were used to drag through the pipeline to remove material. And the one on the lower left-hand side is a pig that's accumulated a little bit of wax. My favorite is this one. We have never figured out exactly where this came from--whether it was used or not or for what purpose--but it does look like it would be a great cleaning pig. But the industry has come a ways since then.

The next thing is why you pig a pipeline. To begin with, pipelines are the best way to transport oil and gas from production areas to markets. And pipelines are operated in extremely harsh conditions, a lot of which we cannot see inside. So we have to make some assumptions that we have to do some internal maintenance in these lines. In a lot of cases we don't do anything as much before until we absolutely have to do it and that point even though it is too late.

Again, the pipeline is the most efficient method of transporting liquids and gases. There are three basic requirements: It has to run all the time, it has to be continuously operated; the throughput of the line has to be maximized with the least amount of capital expenditure; and cost, operating cost; and, last but not least, you need to maintain the integrity of the product. If you look at the last two on there they don't add up. Because if you're trying to operate a pipeline with the least amount of cost and expense, it's very difficult to maintain the type of integrity that we have to have.

Some of the practical applications are pigging during construction, pigging during operation and pigging during the pre-inspection cleaning phase of the life of the pipe. During the construction side, the trans-Alaskan pipeline was probably the biggest thing that's ever happened to the pipeline industry. So most people are interested in exactly how all that came about and what was done during the construction of that. But during the construction side, we have three different phases. One is that we are trying to remove debris and the surface rust that's on the pipe. Anything that could potentially get inside the pipeline during construction needs to come out, including rust. The reason for that is pretty obvious. Rust can be a good environment for future corrosion. It can also plug filters in pumps and compressors and so on. And it's a good time to get it out of the pipeline.

The next part up is gaging the pipeline, hydrostatically testing the pipeline and, again, the second part up is commissioning. And commissioning can be anywhere from just dewatering the pipeline to actually cleaning and driving when you took it through the system. What do we remove during construction stage? Anything that you possibly would see on the pipeline site: buckets, welding rods, spacers, in between welds. Personally, the strangest thing I ever gotten out of a pipeline was a cat that wandered into a piece of pipe overnight in a construction area. But these are things that we have to get out, because these will play havoc in the future and also have the potential to be things like galvanic cells that may cause destruction of the pipe.

I showed this picture for emphasis purposes. This is two parallel 12-inch lines that begin putting in. The one on the left has not had a pig through. The one on the right has had one. This shows the effectiveness of running a pig through a pipeline during the construction stage. It is very, very important. In a lot of cases, the contracts are to put out--the contractor has to run a pig through the line and that is his individual responsibility. But, as you can see, cleaning the pipeline during that stage is a great operating environment to do that and access to it is--it doesn't have hydrocarbons in it, so it's a great time to go in and clean it.

This is a typical picture of a pig being put in for a hydrostatic test. It is a standard-type pig. And this is what it looks like when it comes out. And note the water quality that you see. This water's dirty. And this shows all the debris that gets inside the pipeline during construction whether it is sitting out in the pipe yard getting rust, perhaps water quality that has been put in for hydrostatic tests but it shows the effectiveness of what we're trying to do regarding pigging during construction.

During the operation there is a number of different stages. One of them is to remove material on the inside of the pipe--which is something that is of concern every day. Debris such as wax, sand, corrosion by-products, scale, in faulty water lines, liquid removal in condensate from gas lines, and also liquid removal from water lines where you got high parts of water and the other is corrosion control. The corrosion control is obviously the most important, I think, and what is the main emphasis of this conference.

Getting scale out of a pipeline, wax and so on, is extremely important as well because of the efficiency. Another thing, which you have seen today with having to do some inspection work, is that some of this material can accumulate in a pipeline over time and become so much of a volume that it's very difficult to get it out. There is a concern about running a pig and getting it stuck. The other thing is where to put all this material.

Pigs are relatively efficient, so even if you run an inefficient pig it's going to remove a lot of this material. Periodic pigging of this is necessary so that you maintain control over the amount of material that is in the pipe. It is something that is manageable. And that goes with whether a scale or wax, sand, condensation, and so on. Scale is very difficult to get out because sometimes it requires very tough, hard pigs which can be difficult to get through pipelines. Wax can be a problem because it, too, can be thick and hard to remove, and also have large volumes.

If surface deposits are not removed, water will collect under it, which can cause corrosion. It can prevent inhibitors from reaching the affected area, and also decrease throughput in raising differential pressure. There was a comment made earlier about the amount of material that is in the pipe and whether or not this perhaps was some concern during some of the leaks. And if you think about it, any kind of chemical you would put inside your pipeline is being absorbed and eaten up by something consuming it. If there is nothing in the pipeline, this is going to treat the surface. If there is sand, if there is wax, if there is water. These consume the amount of inhibitors, wax solvents, and so on, which go inside the pipe. It is very important that the material come out. Not only, again, for flow reasons, but also the fact that it can be a great agent for corrosion.

I have some pictures here of just some stuff in pipelines, things that have been removed. In this particular case it is some corrosion byproducts from the pipeline that has not been pigged in a while. This is a line that's got a lot of water in it. It's got some carbonated scale, which can be extremely difficult to get out. And I believe there are some lines on the Slope that have similar problems to this. This is another pig pushing out some corrosive material. And I would like to note on this--this is a pipeline that is regularly pigged. But it is pigged with the wrong type of pig, and trying to come up with logic about different pig designs and what you need to use cannot be dealt with in this period of time. But in this particular case there is a particular product called conical cup. Conical cups are very, very good for certain applications. In this case it's not very good for removing scale. This particular pig was run before an inspection pig, and it's a problem where we got material outside of the pipe. So, the type of pigs you use in these applications are equally as important as the fact that you are pigging your pipelines to begin with. In other words, you can pig it with pigs that don't do anything--that don't do much inside the pipe.

Wax control: Wax control. All pipelines that have any evidence of wax whatsoever should be pigged on a very, very regular basis. Even if you have temperature in your pipeline which would normally keep wax from building up on the inside, periodic pigging needs to be done just to ensure that you don't have any pockets where you may have lost some temperature or someplace in the line where this wax may have tried to accumulate. It increases pumping costing requirements. In a lot of cases when we talk at functions like this, the sheer fact of the efficiency of pipelines in regards to pumping costs never comes up. It's primarily the focus of the corrosion side. With that said, water can collect under the wax and be very difficult to get inhibitors to the affected areas.

This is a picture of a piece of wax that came out of a pipeline. And this is a pipeline, as a matter of fact, this is in Indonesia. And this line had regular solvent put through the system, but as you can see it did not work. They did not put enough quantity in it to get to it. Underneath this section of wax was a piece of pipeline that was corroded. Even though we were putting inhibitors inside the pipe, it never got to the affected area. The deposits and debris that you have in the pipeline are extremely important to remove if you have any kind of corrosion problems at all in oil lines.

Condensate removal: Condensate removal in gas pipelines is extremely important. Not only can it cause a restriction in flow rates and the efficiency of the line, it can also be a great avenue for corrosion. Corrosion inhibitors are placed in pipelines with liquid on the inside need to be very specially formulated in order to treat the water itself, to get down to the very bottom. You also find issues with this in bacterial corrosion. It is great evidence--a great place for water to accumulate and for it to occur. Another one is condensate removal with the pig. We use pigs to remove condensate on a regular basis in gas lines.

This is a crude drawing to represent what I think some of the problems are in the North Slope. And that's in your oil lines where you've got a lot of water. You've got a lot of mechanical issues with your lines with regard to the design. You've got a lot of caribou crossings. We don't have those in Texas. You have a lot of road crossings, but most of the time you have a tremendous amount of bends in the system, whether they are 45 or 90 degree bends. Which means you have a lot of elevation changes. If your flow rates are going down, velocities are going down, it's very, very easy for this water to try to go uphill but flow right back down to gravity. It's also a good area for sand and any other kind of material to try to accumulate. It's not going to get out unless you have higher velocities to push this out. Pigging is the only way to remove this material from the system in order to be able to get in and try to treat potential corrosion areas. Again, corrosion control--once an area is locally corroded, it is very difficult to control it after that point. Pitted corrosion is even more difficult. It creates the best and the worst of the situation over time if it is not pigged. Secondly, it greater requires drastic and costly inhibition programs to contain it. One thing we say in the pig industry is once you got it you can't get rid of it.

Here are some pictures that were taken, again, of corrosive material out of pipelines that were inhibited. And we still had issues with the line corroding because of this material laying at the very bottom of the pipe where we could not get corrosion inhibitors and biocides. From a maintenance pigging standpoint, one of the most difficult things to do is clean corrosion in pits. Here are some examples of some larger pits and some smaller pits. I would like to explain to you a little bit of why this is such a difficult thing to do. If you look at most of the pig manufacturers, you're going to see heavy-duty brushes. And these are very, very good for cleaning surface deposits. But if you take those brushes and you mash them down on the pipe wall, you are not going to get penetration of these heavy-duty brushes into the pits. Because in most cases, the pits are small. So for years and years and years, the industry said if you've got corrosion, run a lot of heavy-duty wire brush pigs. And it's true that you need to because you need to get this material off the surface. But the real problem is not that material. The real problem is what's in the pits. And they're extremely difficult to clean because they're so small and so irregular.

This is a little example of a heavy-duty brush over some pits. And we have block brushes, and there are a number of different types of design of these things which are good for different applications. In most cases if you have a pig and you are running it in the system and you have corrosion in your pipeline, and you are running really heavy-duty brushes, it's going to ride straight over these areas of corrosion. You've got active cells, you've got biocide on top of it, and unless you abrade that you cannot get biocides to the affected areas.

So even if you pig your pipelines, if you don't pig them with the right pigs and if you don't understand how these pits have to be cleaned, the maintenance pigging of this line cannot necessarily result in corrosion rates--to put a stop to them.

What we're trying to do is get small brushes down inside these pits to abrade them. In cleaning the pits, you do not have to have the pits completely cleaned. You just need to abrade them enough to where biocides and corrosion inhibitors will penetrate down in these active areas. The problem is not abrading the bio-film at all.

This is a picture of a gas pipeline that was corroded. The size is similar to the examples or applications of pigs. In this particular case, this was a 12-inch gas line, and I show this because I want to show the effectiveness of corrosion removal. This is the line that blew out on the top. And in this particular case we had some water accumulate over the very top and we were treating the very bottom portion of the line. And if you can see this, it's so definitive as to the effectiveness of corrosion inhibitors if you've got smooth clean pipe as you move to the side it becomes rougher and when you get to the top it becomes very pitted. And this line was regularly pigged with brush pigs and we still had a blow out.

We estimate that it takes approximately twice as much corrosive inhibitor to treat a line properly, even if it has a very, very thin film of debris on the very bottom of the pipe. So in addition to potential corrosion rates increasing, your cost of treating this could be double, triple whatever, if you have any kind of material on the pipe wall.

Another thing we saw up here was problems with material inside the pipe. And in some cases, unknown volumes and what to do with it and how to get it out. There was some concern on some of the BP lines about this, and we came up with, in the industry, something called progressive pigging which is coming in and using different types of pigs with different hardnesses and aggressiveness to gradually move this material out. It shows a line with come uneven distribution of material. This is one of the pigs that has been selected for this progressive pigging program. And I use this--this is the most aggressive that they are going to run. But if you take off some of the cups, you take off some of the disks, you take and change some of the brushes--this will get you down to a pig that's not very aggressive and would have a tendency to leave more material in the pipeline to gradually move it out. And, again, this happens to be a picture of the most aggressive pig you are going to use.

This is another pig that can be recommended. It's a foam pig. There is one displayed in the exhibition hall. This is a foam pig that's very, very soft, it's very similar to the foam that you're sitting on. This is the gray material. The white material in the very front is a harder density material, and we use this because we knew that this would not remove very much sand and sediment in the pipeline. So, several of these were run through the line in order to make sure that there were no large volumes. This is a very safe way of entering into a pigging program to where you know what you've got inside the pipeline.

Pre-inspection cleaning: We did some inspection runs that have been done. These are extremely sophisticated tools; highly sensitive; very expensive. But getting a good run through the system is very, very important. Cleaning pigs and maintenance pigs have a great importance in this. First of all, a dirty pipeline will affect the data, if you get the data at all. It can also damage parts of the pig. Sensors and magnets are very, very close to the pipe wall these days, compared to some of the older technologies. In a lot of cases what we are going to do is called pre-inspection clean. We are doing it after the line has not been pigged in a long time. We use very, very aggressive pigs. In some cases more aggressive than what we do on a regular maintenance program. And also your vendor should have something to say about how clean your pipelines are.

You have to remember in these contracts that if you leave the line dirty they run a pig and they don't get any good data out, you're going to pay to run it again. If the line is clean, they have a bad run, most cases they are going to make them rerun them on their own dime. So it is very important that these lines be clean.

This is a picture of a pig before it went into the pipeline. You notice that it has a lot of brushes, it has magnet sections, battery sections and sensors. And this is what can happen to a pig when it comes out even if the line is not real dirty. In this particular case you just have some surface material on one of the sensors or magnets. Whether they got good data runs or not, don't know. But in a lot of cases if you run through some crude lines like you have today and you do get it pushed through, you will end up getting a massive amount of material on those pigs, and that needs to be alleviated. Two things I can tell you about this is, number one, the best cleaning pig that has ever been built is an inspection pig. It is also the most expensive. So, if you have a vendor and have a dummy pig, this may be one thing you want to do to try to clean your line.

The other thing is how clean is clean? I think there are different opinions about this depending upon the technology. From the cleaning pigs people side, the lines cannot be too clean. So how clean you do it and where you stop it, if you have to run an extra pig, it's something that should be between you and your inspection vendor.

This is another pig that was run right before an inspection. You see some of the material that the pig brought out.

Here's another pig that was run right before an inspection pig and, basically, we have what looks like used coffee grounds on the ground. It's corrosive material from the pipe. This line is another line that's also pigged on a regular basis, but it was pigged with spheres which are very, very inefficient pigs.

This is another pig that was run on the line. In this particular case, a line with wax, right before an inspection pig that shows wax on the brushes.

This is another pig that was run prior to inspection. You see the dirtiness of these lines and what material that's got to come out of the line before we run an inspection program. Not only that, if you can think about this material being in your pipe and you put in something like corrosion inhibitors in it, it's not getting to the affected area.

A little bit quickly about pig designs, there's all kinds of different pig. Every pig in a different color, different shapes, different sizes. In most cases, all these pigs do something valuable inside the pipe depending on the application. This happens to be a cross-section of a four-cup mandrel pig. This is a disk pig. For those who are not real familiar with what disk pigs are, they're basically slapped with urethane or neoprene that act kind of as a weight as you go through the system. And there are all kinds of combinations of these anywhere from two disks, to six disks, eight disks and so on, depending on what you are trying to do with it.

This is a scraper cup pig. It's a little bit more aggressive than conical cup pigs to remove material.

These are foam pigs. Foam pigs have been around since the early 60s. They basically are very, very expensive furniture and they have great tear resistance. A very good tool to use in the rehabilitation and some aggressive pigging of your systems, and they come in all different types of design these days which can be utilized in a lot of good cleaning. These are some pigs that are good for removing sludge, sand, liquids from the line. We have one pig that's shown out in back that has razor wire on it and can cut through calcium carbonate scale.

This is another pig. This particular one is an all urethane-type pig. Again, there are so many different pigs. These are all urethane pigs as well. One-piece pig. Which a lot of operators like to use because simply put they are easy to get inside the pipe, take it out, there is no building to it. They're more expensive but the labor involved in them is a lot less than getting parts out.

Clean pig applications: Cleaning pig depending on type of debris and deposits. When you go in and start inspecting pigs, you need to take a look at this. Just don't buy pigs. There's a large number of different pig types, there's a lot of qualified vendors that can help you out with the type of pigs that you need to use for your application.

In this particular case, cleaning pigs--there is different cleaning elements, brushes and urethane parts that are like blades. I particularly don't care for the urethane blades because they have a tendency to take material such as wax and just move it to the side, not really try to get it out of the line. Your brushes are going to be your better cleaning pig.

These are some pictures of several different types of cleaning pigs. This particular one with blades, with brushes, and I would like to note something. When you're looking at some of the pig developers. There are several types of brushes and springs. We have what's called cantilever springs. Cantilever springs are attached to the pig body on one end of the spring. They bend very easily. They can go right over hard scale. This particular type is what's called a leaf-spring. It's connected at both ends. This will not give you the flexibility that cantilever type--which is a better type of arrangement when you are trying to remove scale from the line.

These are green brushes. Again, there's so many different varieties of maintenance pigs. It kind of boggles the mind. But all these things do have their own purpose depending on what your application is.

A little description here of cantilever springs that--although the guy that did this did it upside down. This is a cantilever spring. This is one reason why selection of a maintenance pig is so important. A pig, a spring that is so flexible it will go right over a hard deposit, will not necessarily clean. So just because you're running a pig through the system, don't get false hopes on it.

A leaf-spring brush will not have that flexibility and it cuts through deposits. So it is important when you select your pigging program that you select a pigging design and take this into consideration.

We also have things that we can put on such as take a hard disk and put slots in them, to help cut wax in material to disrupt it off the pipe wall. Put on circular brushes. We also have foam pigs that are perfectly clean pigs with a variety--we've run out of names of pigs. This is called a stud pig because it has studs embedded in it. It is good for calcium carbonate.

And, last but not least. Here is some of the areas where I saw some pigging concerns on the Slope. One is if you don't have--not every line has good pigging facilities on it for launching and receiving. That's a very, very high investment--capital investment. It's very difficult in the abilities that you have to just go in and start putting new launchers and receivers in. The other is tight radius bends. We do have issues, especially running mandrel pigs through the line and big brush pigs through the line on short radius bends. This can cause problems not only with pigs hanging up, but also the type of pig that you can run. There are certain limitations. That's something that your pig vendor needs to know.

The other one is the volume of debris removed, which in some cases can be enormous. So you have to take that into consideration. You don't want to run a pig that is so aggressive that it's going to remove too much material at one time and get stuck. Also, some multi-individual lines which is in itself a lot of major problems. Anytime you have dual diameter lines something is going to sacrifice. Either your larger diameter, or smaller diameter.

Just a little bit about dual diameter pigs, dual diameter pigs have to be flexible enough to go through both sizes. There's some enormous technology and development that's been done in the Gulf of Mexico in the last three or four years. On the Mardi Gras and Thunder Horse projects with dual diameter pigs going multi-multi-sizes. It's incredible technology. There are people here from BP and the Gulf that can explain if you are interested in dual diameter lines. You can also see where it's a problem with brushes if you've got dual diameter because brushes have to be flexible enough to go through the smaller diameter. And these are some of the pigs that we use today to do that type of work.

In designing a pig program, I'll leave you a little on this--analyze the history of the pipeline. Look at every single thing. I think a lot of the things that's happened in the Slope since March has caused people to go backwards and take a look at some of the things they've done, some of the things that they should have done in regards to their pigging program. These things need to be taken into consideration from how much debris you have in the line to what the hardness is, how are you going to get it out, contingency plans for stuck pigs, and so on.

Sludge and clean pigs: Once you get the line clean you should run the rest of the pigs that you can run and run them as often as you possibly can. And I do this for a little while. Everybody knows what pig signalers are? And pig signalers are known for not working because they're intrusive, they go inside the pipes, they're subject to everything that goes on inside the pipe: corrosion, scale, wax, abuse, something that moves inside the pipe that always---- This is what I would consider a mediocre pig detector. This is much better. (Laughter)

I thank you for letting me speak for a few minutes. Again, you cannot cover this stuff in 30 minutes. I am here this afternoon and there are several other vendors--maintenance pig vendors here that will probably help.

TRANSCRIPT OF QUESTIONS FROM PANEL

Moderator: Thank you very much. Great presentation. Now we're going to have 15 minutes for questions from the panel that we have in front. I would appreciate your doing two things. If you have a question, first raise your hand, and I'll recognize you so we don't have five people speaking at once. And, second, we need you to speak into a microphone. So, if you're not speaking into a microphone, that's not good. People will not be able to hear. So, does anybody from the panel have a question for Gary?

Yes, please.

Q: You alluded to----

M: Can everybody hear? You just need to speak directly into the microphone. And speak up just a little bit, please.

Q: You alluded to----

M: I'm sorry. Could you just introduce yourself by name? I will be introducing the panel to you this afternoon. But, please start with your name, please.

Q: I'm sorry. My name is Cathy Foerster. I am with Alaska Oil and Gas Conservation Commission. You alluded to increased regulatory requirements for pigging and we're aware of Federal requirements and State requirements. But could you give us a description, of examples, of increased State requirements elsewhere across the country that we might learn from?

Gary: I'm not an expert in that subject. A couple of the inspection companies that are here probably are more in tune with those regulations. In the State of Texas we have DOT, Railroad Commission, regulations that cover certain lines in Texas and are probably not covered elsewhere. But we operate under the main guidelines and everybody is operating right now with OPS and DOT. What I meant by that comment is that now that we have to inspect the lines more often, the cleaning side or maintenance side is becoming more of an issue. So a lot of these pipelines have not been cleaned in a long, long time. And in some cases they didn't really need to be cleaned. It's just that they had to be cleaned prior to inspection. As far as other regulations, I think there are at least three inspection companies here and I would encourage you to speak to them because they're fairly knowledgeable on the regulation side.

M: Thank you. Does that answer your question?

Cathy Foerster: Yes.

M: Any other questions from the panel? Yes, please.

Sam Saengsudham from the ADEC: Have you seen any more projects done on the flow lines or other kind of lines? I know you've done some oil line and gas lines. How about flow lines?

Gary Smith: The flow lines we have here are a little bit different than the ones we normally have down in the lower part. You have much bigger flow lines, and from our standpoint, the flow lines are basically from the well head to the tank somewhere. In most cases those are not pigged other than the lines that have a lot of wax in them. So, I don't think the tendency has been to actually go out and pig those lines. Your definition of a flow line is different, and the closer to the well head probably the more susceptible you are to a lot of trash in the line, also causing bacteria problems. So I would think that is something that needs to be addressed. And this stuff is coming from somewhere. But as far as a lot of cleaning in the United States with flow lines, the regulations really have not gotten to that point, and most of what we've got are 2-inch or 4-inch and would never build. They are threaded fittings. It would be a big deal if they start maintenance cleaning flow lines.

Sam Saengsudham: Do you have any large diameter flow lines?

Steve Sauer: We have a lot in the Gulf of Mexico and they are being pigged.

M: Does that answer your question? Okay. Other questions from the panel? Yes, please.

Dave Hart with Pioneer Natural Resources: Can you speak to any nuances of pigging subsea pipelines or buried or above-line pipelines. Are there any differences there?

Gary Smith: There is a lot of mechanical differences. There's a lot of fittings difference. In the Gulf of Mexico, and I'm sure it's like that here as well--it's all around the world. The type of risers, the type of flexible hoses, manifold, and so on that we have to deal with are so much different than it is above-ground. As far as different types of pigs. I think that you would find that some pigs are being developed for offshore in Louisiana recently are just very, very unique things, and are a lot different than what you've seen on the screen. A lot of dual diameter stuff. But with regards to the type of pig itself, we have to take into consideration diameter changes, because you have a lot of in-wall fittings and so on. But when you get past that, you really don't see that much difference in exactly what we're trying to do inside the pipe with regards to the major function of the pig. But it is a big issue with regards to pipe i.d.'s and if they change quite a bit. It's also a lot harder when you get one stuck. There's a lot more concern in more for-thought put into pigging a sub-city line.

M: Are there any other questions from the panel? The questions are a dollar a piece, so go ahead.

Cathy Foerster: You don't have to pay me for my knowledge. , AOGCC, again. Two questions. Are there any upper or lower I.D. limits on what is being pigged?

Gary Smith: Yes.

Cathy Foerster: And what would that be?

Gary Smith: Well, there is a gentleman that's on the panel with you who would be a good one to answer that question. But, I think some of the stuff we've got now is 50%-- difference. What's your biggest change now?

Steve Sauer, BP Mardi Gras: We have 24, 28 and even go onto 30-inch.

Gary Smith: It's a wide variety. At the same time, when you go into a 30-inch pipeline and you've got half-inch wall or one-inch wall--these are things that a pig vendor would like to know just to make sure the pig is designed for that. But when we know that there is large changes, those pigs are specially designed and tested to go through those diameter changes.

M:	Does that answer the question?

Cathy Foerster: Yes. My second question is--are there any chemical alternatives like slugs or gel or foam, that you can run through for maybe a less aggressive pigging operation?

Gary: Yes, there is, but you have to remember that all of these chemical operations still have to have maintenance pigs or brush pigs running with them. They can be used to help dissolve material and to help put some things in suspension. Some of the gel technology--which there is a vendor here today which specializes in gel. Those gels can do incredible things with regards to moving large quantity of solids in the pipe. Yes, they are a good consideration from a maintenance side.

Cathy Forester: Thank you.

M:	Does that answer your question? Other questions from the panel? Yes, please.

Sam Saengsudham from ADEC again: Please comment a bit more on this pitting--you briefly mentioned---

Gary Smith: I'm sorry----

Sam Saengsudham: Can you comment a little more on this pit cleaning?

Gary Smith: Pit cleaning. The first time I got involved with it was on a 42-inch oil line in the Middle East where we had high corrosion breaks in the line that had been put in in a year. They had high corrosion rates. We started--we actually went through a vendor, an inspection vendor, and bulk purchased some tensile brushes that are used with a fine wire, very, very tight construction density. And we mounted them on a pig and within six months we saw corrosion rates go down--bacterial corrosion. So we know that it works. Irregularity of the pits is there is no guarantee of it.. There are several different designs of these pigs out now. We do see promise with these. The only way you can really tell is to have such good monitoring systems, you can actually see a decrease in corrosion rates, with everything else remaining the same. To answer your question, yes.

M:	Does that answer your question?

Sam Saengsudham: Yes.

M:	Okay.

Cathy Foerster: and this will be my last question, I promise. You say that you can't over-pig, but when you've got active corrosion going on if you pig too often or too aggressively can you not run the risk of stripping pipe off the wall? Stripping iron and actually accelerating the corrosion?

Gary Smith: There is an argument that you put a film on the pipe wall with corrosion inhibitors on, and theoretically you can't pig the lines too much to wipe it off. But, I don't know if there's anyone in this room right now that could say that other than they didn't want to do it--that ever had any kind of concrete evidence that the line has been pigged too much. There's arguments in maybe keeping a thin film of something like black powder, or something on the line to protect it, but I think that's just an excuse not to pig.

M: Does that answer your question? Other questions from the panel? Yes, please.

Mark Peterson, BP: Do you see any really emerging technology coming out lately? I know a lot of pigging is pretty old technology. Has anything new come out?

Gary Smith: On the cleaning side, not much. Improvement in urethane material is to give us longer-lasting. Maybe some new technology in the design of cups. I know there's some technology going on right now to try to improve brushes. But from our standpoint there's not a lot of glamour and glory in high technology in what we do on our side. Module pigs so you can run two sections through a line at one time, that are joined by a joint. And there's a lot of specialty-type things. There's some tether tools, tubing tools, but I think that would probably go in more to the specialty side. Derek's going to give us a little bit of an idea of some of the stuff that is on the market for that.

M: Okay, five more minutes allotted for questions. Any more questions? Does that answer your question, by the way? Other questions from the panel? Okay, I don't see any. Thanks a lot, Gary.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

The first question I have is, "Please discuss the problems with--" this is for you, Gary. "Please discuss the problems with the launcher recovery corrosion wear and damage." A pretty general question. Okay. "Please discuss the problems associated with launching and receiving the pigs, corrosion, wear and damage." Kind of a general type of global question.

Answer by Gary: As I understand the question, what are the issues with launching and receiving pigs, corrosion and damage? On the launch and receiving side, it's probably the most dangerous aspect of the pigging industry. It's where you are intervening on each end of the lines, and more than likely you are between yourself and death as the valve may or may not be holding correctly.

I personally in the years I have done this I've seen two dead people and one here in Alaska. Fifteen months almost dead, all on the launcher. So, that's the dangerous part of our business is intervention on either end of it.

I think everyone here that's in the operator side has got a procedure for launching and receiving pigs. And it's probably fairly common, safety-oriented, and but from the standpoint of the pig side the only thing that we really have major issues with is to make sure that the launchers and receivers are designed to meet the pigs, have proper bypass, proper drains. Long enough for inspection pigs. As far as the pig side, launching and receiving, pigs are pretty ignorant and they really don't know much about what's going on except for we are sending a lot of pressure to it. So there is really not a lot of damage when it comes to launching and receiving pigs unless when you are launching and receiving pigs you get a cross-relation of a reducer which--maybe you don't have a valve completely open. And that does happen more often than you'd think where a pig is damaged when it is launched.

I'll give you an example. Recently we had a 30-inch mandrel pig that these things had equalization ports around the main body and collapsed the body. It's a piece of pipe that has plates on either end.

We also have little plugs in the back so you can flow through the body and have bypass through the body. And an operator welded plates on the holes and mounted some temperature probes. And when he launched the pig he called and said, "Your pig has exploded." And after traveling 200 miles and we got it out the front plate was blown out. Actually, the front plate was inside the pig. And what had happened is that after you welded those parts and applied pressure to it, it imploded. And the weakest part of it was the front plate and it came out. This is the types of things that we sometimes see.

We also see some of the things when launching and receiving when you have a pig like that where it's pressurized on the inside. And when you take it out of the line it's actually got pressure in it. It's not all that common, but it does happen where someone will unscrew a plug and try to take the pig apart and it's actually a pressurized vessel. That's about all I can say about the launching and receiving side of it. Intervention with the pig manufacturer would probably alleviate those kind of design issues. I guess one thing that can be said was that reducers for launching and receivers--it's good to have some specific types in order to be able to have a smooth transition to get the pig in and get the pig out. And you want a flat surface basically to scoot it into a reducer and to seal it off as opposed to something like a specific reducer where we have to go up a lift.

Other than that, from the pig damage standpoint, pigs are damaged by a number of things. Wear is probably our biggest concern--where we spend our time and effort on a urethane problem. But other things can damage pigs--anywhere from coupons, bent pig bars--a lot of debris in the pipeline and things like this.

M: Okay. Anything from the other presenters that you want to add to that answer that was given?

David Newman: I would like to add that every time the launcher and the receiver is open it is supposed to be metal to oxygen in otherwise entering the system that it doesn't have oxygen in it. And I believe through our chemical vendors that started using basically a bag with oxygen scavenger and corrosion inhibitor in it.

For a couple of reasons, mainly the launcher and receiver to open it up. And that has reduced the corrosion rates in the launchers and receivers to a fairly good extent. Because we've had a lot of corrosion at the face of the doors on the launchers and receivers, and getting a tight seal is a very important aspect of launchers and receivers. Maintaining the pressure, especially on water injection lines that are running around 2500 pounds.

M: Anybody from the panel have anything that you can add based upon your own personal experiences in terms of problems that have not been addressed so far? Yes, please.

Bill Hedges, BP: I think Gary made a good point in his answer. That we're here today to talk about pigging. And a little bit like Maureen, this morning I felt a little bit awkward being here, because I don't see why I have to talk to you about maintenance pigging. But we do run a bunch of pigs every day. And we see much that sort suggested, that you've got to think twice about pigging. You just grab a pig and put it into a high pressure system. Actually there is a lot of risk associated with putting a pig in a high pressure system. They just mentioned nothing light--2 to 3,000 pounds of pressure. And some of the old lines are--all we against to block us from those high pressure outputs is one safety valve. So what people like to do is try and use two valves to meet at a point in the middle so you can pretty well isolate the right but all of normal equipment only has one safety valve. So, pigging itself also is very useful in reducing some types of risks. Also it has a certain amount of risk associated with it. In our conversations about pigging we should never forget that. I thought maybe we should remember there are risks involved in pigging.

Gary, when you opened your pigging traps to let the air in we've seen some internal corrosion on our pig launchers and receivers due to ingress of oxygen, and again the more you pig the more oxygen you let in. And so the problem becomes a bit more difficult to manage.

M: I apologize for ignoring you as being someone who speaks with the right English as well.

Derek Clark: I'm not sure if that's exactly the right English. Pigging operations are routinely conducted by us and I would say it's a very controlled operation, and we all observe pig's procedures. A couple of other things I would like to talk about. We would normally purge the pig trap with nitrogen prior to opening the trap to make sure there was a safe atmosphere in there.

And the other main consideration for me is the type of material you are going to remove. Hydrochloric materials have a tendency to combust and you also have a chance to have normally are going to react to. So you really need to know before you go in there to think about the safety of the guys that are handling the pigs when they come out.

It really is not unusual to get hydrochloric material. I don't know if you have that on the North Slope or not but it is quite commonly found, and you'd better have a system to---- Pigs can go on fire literally 12 to 24 hours after they come out of the line--they will just combust. So you need to be very, very careful about how you handle the pigs when they come out.

M: Okay, next question, and once again, Gary, this will be directed to you and then we'll open it up to others. "Could pigging brushes pack solids (product) in the valves or other pockets, possibly enhancing the corrosion potential?"

Gary Smith: I'd have to say that your exertion and outward pressure on any pig that is being run and including brush pigs, and if you've got voids in your line during pigging--bellies and valves or sidetaps, such as T's--any place that you could potentially put your material it will go, including pits. And from that standpoint if you've got a material that has a potential of corroding metal, it could get in there in the dead space.

But I'll know that when you pig for that. You just have to know your system and be able to exercise the sensitivity. You can flow through these areas or put chemicals or something in the areas where a pig could potentially put material. And, yes, it will.

M: Other comments from the panel? Other presenters or panel members?

You've got to be careful here, you put your arm out I'll call on you. Any comments anybody?

Please.

Bill Flanders: Those pipeline valves are through conduit so there's not an open void in the bottom of the valve to push the debris into, but there is a slight gap there, and so water can drop out and form a corrosive environment in the bottom of the through conduit valve.

M: Any comments?

Gary Smith: Procedure for running valves on a periodic basis and I've seen corrosion inhibitors actually pumped through valve seats and when you know you have that corrosive system with liquid in the valves, it is actually displaced with some types of inhibitors.

M: Any other comments? Okay. The next question for you, Gary. "What definitions of 'clean' are there related to different product pipelines?"

Gary Smith: Okay.

M: Good question. You stumped Gary.

Gary Smith: Well, as somebody said before, it's--I guess there's two ways to look at this. One is operational clean and one is inspection clean. So we'll take the inspection clean away for a minute. We've seen stages of the gas lines being cleaned and cleaned on an extremely regular basis.

One thing that Derek mentioned is hydrochloric material. I don't know if you've got that kind of problems here. What we saw for years, decades, of light dust in the gas lines is now considered dirty and you've got to get it out. With product lines, I don't know if you're familiar with any of the pipeline in the states, but I rode around a plant in Houston with the aviation fuel director from Texaco, and I showed him some of the pigs that have come out of Centennial line with jet fuel and various other things, and it's surprising how much rouge and bacteria we have in these lines. But I would imagine that the standards on that is not to have any at all.

But with regards to crude lines, I don't know that there is that much standard other than trying to alleviate corrosion problems and then your water issues. So is there a specific specification on this other than sampling--internal sampling? Pig run today with contaminants or sediment in it. All I can tell you is in the pipeline industry today, pigging has suddenly become a big issue and they pig lines that normally would be considered okay and now they're considered dirty. They try to get the standards a little bit tighter. There's no definition of clean.

M: Other comments from the panel? Do you have a question? Okay. Just a quick follow-up on that, Gary is going to be related to this. "Other than output ahead of the pig, how do you measure when a pipeline is 'clean'?"

Gary Smith: Other than what comes out in front of the pig?

M: Yeah. Output ahead of the pig.

Gary: There are some devices, there are some data loggers than can be run and measure the vibration if you've got some luck with before and after doing these projects. There are some caliper pigs and, as Derek mentioned, there's some deposition pigs that are being developed. But one good thing is that a lot of time you have a cleaning program and you are getting ready to do an inspection run. And as I mentioned before the best cleaning pig is the inspection pig. So, how do you gage whether or not you've actually cleaned the line after the pigs come through? We recommend pigging again using the most aggressive pigs you can use, and normally if you've got material in the line you'll see some sort of sign in and on the pig--brushes or on unclean disk removes or in your receiver. It is a very difficult thing to actually measure. We haven't come up yet with an instrument to tell us whether or not a pipeline is dirty or clean.

M: Any other opinions on the panel? Yes, please.

Bill Hedges: There's some very clean service lines. I have seen actually some work done here in Alaska where they take and they put cameras onto it and look inside pipelines to visually see if they are clean. But for crude oil lines, particularly large diameter lines, I think you really have to rely on what you see on the pig. We have tried x-raying through lines, we've used various radiation techniques to look for sediments and it's not an exact science. I would suggest in crude type lines, you would need to rely on the pig to tell you how clean the line is.

M: Any other comments?

Gary Smith: I'd like to make one more. Even though pigs have a certain amount of wear, just friction wear, when you run it through a system. Maybe it's a gas line with high speed, or it's a crude line with scale and things like this and you've got weld seams. For people that are eaten up with this pigging stuff like we are, we can usually tell from a pig when it comes out what it's been through. And if you've got a pig that's chewed up we normally know that there's some place in the system where there's still scale, there's still material in it. It's a--these things kind of tell a story when they come out.

M: Any other comments from the panel? Okay. I'm working on having this projector moved out of the way, so you'll have an unobstructed view of the panel. Yes, please.

Mark Peterson: I just wanted to clarify one more thing, the--sometimes it is a misnomer of what's--they say well, how much do you get out of the receiver. Well, what you get out of the receiver depends. There's a huge variety of reasons you do and you don't get stuff out of the receiver. It depends on your out take, it depends on your flow velocity. You can bring in a very dirty line and show very little on the receiver. On the other hand if you have a good set-up for your out take or your flow line, it just depends on the diameter of your out take lines, your outlet lines. It will be an indication of how much there is in there, but it can be pretty deceiving.

M: Okay. Any other comments? The next question for you, Gary. You used some photos this morning in your presentation of actual pigging operations, and the question is, "Especially in regard to the pig receiver operations and brushing cleaning, were these photos from the North Slope or were they taken somewhere else?"

Gary Smith: None of these pictures were from Alaska.

M: I think we're done with that question? Okay.

Next question for you: "You said the pigs push out 'corrosive material.' Is the material actually corrosive or is it more a corrosion by-product?"

Gary Smith: That's kind of a plus term that we use in the industry--it's corrosion by-products, not actually corrosive material.

M: Does anyone have any comment on that? Is everyone in agreement? Yes, please.

Bill Hedges, BP: I would just add that some of the reports associated with the crude oil spill there were suggestions that we had viciously corrosive stuff in our platforms and very corrosive stuff in there chewing away at the lines, and actually I think the follow-up was "inactive corrosion products." And so they were not themselves corrosive--but what they did do was provided an environment where they could promote corrosion. I think everybody in the room is familiar with those subtle differences, but to many people seeing that we've somehow allowed corrosive solid acids or whatever to get into our lines is very disconcerting.

M: Any other comments? Anybody want to elaborate? Yes, please.

Tom Johnson: On some of the maintenance pigging when it displaces the water, the water's going to be a corrosive species so in a sense when it displaces then it is a really corrosive species on the line.

M: Okay. I see people going this way, so there seems to be agreement from the panel on that. Any other comments? Okay, Gary, you're doing a good job. Here is the next question for you: "What is the difference between dual and multiple diameter lines?"

Gary Smith: It's kind of one and the same, but at one time in our industry, dual diameter and multi-diameter lines were the same--it was like 18 to 20 inch. But from the advent of most of the stuff in the Gulf of Mexico, one of the other panel members down there, now they do it where there is more than two sizes, so I think that dual diameter pretty much indicates two, and multi-diameter means that we've got more than two.

M: Okay. Agreement amongst the panel? Any comments? Okay. Next question: "What is the typical cost to install a pig launcher and receiver?"

Gary Smith: From $1000 to $1 million. It really depends on how long it is, all the parts and pieces that are bolted and welded on to it, the rating. I would not have any idea of the cost. In some cases I would imagine the steel may not be the major problem, the with actual installation, especially if it's an existing line.

M: Okay. $1000 to a million is quite a range. And somebody said something more. Does anyone want to elaborate on this, or----

Bob Gray of ConocoPhillips: I think we have to say that a most typical North Slope launcher and receiver would run over $1 million. I don't know the exact range, but it's a lot more than that.

M: Okay. You don't have any of the $1000 variety on the Slope? You can't even get a consultant for $1000 on the North Slope. Just trying to defend my trade here. Just another quick question from the same asker. "How fast does a pig travel down a pipeline?"

Gary Smith: How fast does a pig fly? I think that anywhere from a basic crawl--inches per minute. The fastest pig that I can remember actually having documented is 40 meters a second. Which is in a line that's owned by Aramco. But normally we try to recommend that you go to 3 to 10 feet per second, that's a good clean, safe speed. It's fast enough to entrain solids in front of the pig, but not too fast to have something that is kind of uncontrollable in regards to receiving it, but in most cases especially on conventional pigging we are going with the flow. No one is going to slow down production of the pipeline or probably add anything to it just to run a cleaning pig. Whereas on the inspection side, they do have some more--they have some constraints and restriction on the high end side. But I'm not too sure exactly what the common speed of flow is on the North Slope--between maybe two to five feet per second--does that sound about right?

M: I see heads going this way again. Anybody have a further comment? Please.

Mark Peterson: You are allowed a wide variety. We smart pig the full length of the Flow 2 line at .4 feet per second which is really slow for a smart pig, but I guess handing it to BJ, their technology is to get rid of what all is in there. But normally we try to keep it as Gary was saying, three to seven feet per second is kind of our range, what we like. But with the downturn in North Slope production you can't always get that, but that's what we shoot for. And it depends on what kind of environment you're in. A solid fluid environment for a total line, like an oil transit line, you can travel slower. If you have a mass behind you. You want to be a little more careful about doing that with gas--a three-phase line or gas line. It will give you a corner and then build pressure and it'll shoot forward, so it depends the type of service you're in and what you're trying to accomplish with it, but it's anything from 1/2 foot per second up to 10 feet per second--that's about the fastest I've ever seen on the Slope.

M: Okay. I have about 15 more minutes for this first panel discussion. So just keep that in mind, as you give your answers, we have about 5 or 6 more cards to go through here. Okay? "How quickly should a natural gas line be pigged for cleaning purposes?"

Gary Smith: How frequently should a natural gas line be pigged for cleaning purposes? If you've got some historical records on the pipeline if it's producing wet gas or does have some corrosion problems--it's got some highs and lows, any kind of buildup on the inside, I'd have to say every month. You're asking someone like a tire salesman how often do I need to change my tires? Every week? So, from a standpoint of asking someone in the cleaning industry, as I said earlier, you can't pig it too much and the more often you pig it the better off you're going to be.

I can't see anybody that is going to run into a financial problem by running cleaning pigs. But on a gas line I would probably say anywhere from once a month to once a year. And we have some situations where you are producing so much liquid that they are pigging more often than that. We have a case right now in Trinidad on a 56-inch gas line that they're running once a week because they are producing so much liquid. So it's a case-by-case situation.

M: Okay. Any other comments on that question? Okay. "Earlier in the day it was stated that 'flat' wire brushes do not adequately clean pitting defects. What type of brush is recommended and how do you get adequate brush tensile strength to sufficiently clean the pit?"

Gary Smith: In the brush business we've always tried to go with the more heavier duty brushes, which is common flat wire brushes. It gives you a better scraping job and is stouter. With a spring-loaded brush your pressure is against the pipe wall, and if you took a typical cleaning brush--a six by nine inch brush--and took a piece of pipe out here in front and put a little pit in it and the heaviest person stood on top of it--the bristles would not go into the pit. The whole brush is trying to lift that whole thing off the pipe. And we found this by pigging lines very routinely through the years and we still have corrosion problems, and we find that we have pits. We also know that when the advent of tensile brushes came in from the inspection industry that there was comments made by people who ran these pigs that their corrosion rates went way up when the pig came in, and then periodically went down afterwards. So we started--people on the cleaning side started getting smart when we started demonstrating that this type of brush would get down in the pits.

And unfortunately I have a 3-1/2 hour presentation, I have a video of all this, but I don't have it with me. But when you take fine wire brushes, they are kind of independent of each other and they are not trying to hold the entire brush up on the pipe wall. They would likely go down into pits as you pass a zone, and again you don't have to completely clean pits out to have a good application for the corrosion inhibitor or biocide. You just need to make sure that you abrade the top surface or part of it and perhaps if you pack anything in it, just widely abrade it in order to just penetrate.

So, from a flat brush standpoint, they're good for surface cleaning. And we recommend in a lot of cases that you put green brushes on pigs with the heavy wire brush in the front of thin wire or fine wire brush in the back to kind of get full cleaning action.

In regards to tensile strength, I'm not too sure exactly what you mean by that. Tensile strength of this wire is pretty incredible. With regards to tensile brushes, the way it's encapsulated is either glued, soldered or crimped together, so we really don't have issues with it coming out of the brushes. It's very rare. And very rarely we would ever find any that break if they are good-sized brushes.

M: You and I can talk about tensile strength after we're done.

Any other comments? Okay. Next question: "Regarding launcher receiver barrels, is there a recommended practice to pickle them between shipping pigs to help reduce corrosion?"

Gary Smith: I think there's a comment mentioned earlier about actual cases here and they are getting some surface corrosion in launchers and receivers on pig runs with oxygen exposure. So, from the standpoint of pickling it or you're not getting nitrogen or putting some inhibitor inside, that is probably a good practice in the fact you have that environment. Perhaps somebody could just look and comment about what they are actually doing on their lines to begin with.

M: Any comments from either the BP or ConocoPhillips representatives?

Bill Hedges, BP: From BP we certainly see what I mentioned earlier, oxygen corrosion in our launchers and our receivers and we've used a variety of methods to try and control it; and I'd say that we're not on top of it at this moment in time, and continue to look for the best way to control corrosion in these areas. And that presently excludes the chemical options that I think we used. But we haven't excluded the use of corrosion-resistant elements to get around this problem.

Dave Newman from ConocoPhillips: Just to reiterate, we have had a lot of corrosion problems in our pig lines receivers and so we do use the inhibitors added and oxygen scavengers. We also on most of them have sacrificial ends that are used to prevent corrosion on these launchers. I guess another thing is pigging frequency and the more that launchers and receivers are opened and exposed to oxygen, the more there is the chance of more oxygen and more need for protection for those units.

M: Any other comments? Okay. Next question, Gary. "On your presentation you touched on economic and operational benefits of pigging this morning. Can you speak further on economic and operational benefits such as (1) reducing pump compressor horsepower; (2) reducing chemical costs; (3) lowering the risk of spill clean-up; and (4) lowering the cost of in-line inspections."

I will give you the first one--in terms of reducing pump compressor horsepower----

Gary Smith: There have been some cleaning projects in the states over the last few years primarily for cleaning black powder out of gas lines where they've actually been able to go back and prove that they paid back the cost of the cleaning projects just with the efficiency of getting gas through the pipe. And I think when you're looking at perhaps a pumping situation in the North Slope where your production is down, you don't look at the pumping costs as much as you did when you were trying to put more fluid through these lines.

In regards to pigging, it does not take a lot film on the inside of the pipe wall to increase your friction rate. So, keeping the pipe clean is going to be the most optimal. As far as putting a figure to that, I couldn't do it, you'd have to sit back and actually look at your pump and your compression cost. But if you think about it, the most effective, efficient part of the life of a pipeline is when it is brand new.

So, theoretically, if you can keep it in as clean a shape as possible, if you don't have any film, any material, any liquid build-up, your pumping costs--compression costs are going to be just by pure economics would be less expensive than it would be if you started to build up material on the inside of the pipe wall, or had to compensate for that and so on.

So, with regards to chemical costs. I used an example in my talk about a thin film of material on a pipeline and the estimated cost of inhibitor--it takes three mills to properly cut a clean pipeline and five mills to treat a line that has a slight amount of material. That's actually a figure that was developed by Amoco's corrosion department years ago and is supposedly fairly accurate as far as estimating, but you have to remember that anything that's inside the pipe is going to consume liquid--whether it's wax or whether it's corrosive materials--anything. If you put liquid in there, this stuff is being absorbed. In some cases you want it to be absorbed, in some cases you don't.

If you have a dirty pipeline, or if you've got a pipeline that's got a lot of wax in it, what you're putting inside of there is in a lot of cases just treating the surface and going along through. So, in order to get a good effective corrosion inhibitor, or something that's going to treat wax, you have to put more and more in it.

So, does pigging reduce the quantity of chemical cost? Absolutely. Again, the best surface to treat is one that is just metal--it has nothing on it, no sand, no wax, no liquids. That's one of the reasons why people pig is to prepare the surface for better chemical reaction.

M: How about the question about lowering the cost of in-line inspections?

Gary Smith: The answer to that question, I think we discussed several times today. I'm not too sure exactly what a ILI run costs these days, but if you look at the cost of running and if you have to make a rerun, you start looking at the cost of every time you put a tool through. Not to mention if the line is dirty that if you damage the tool, which does happen, it's on your own dollar. So does maintenance pigging reduce the cost of inspection runs? Absolutely. Because the cheapest way to go is to run it one time and not damage the tool. And if you've got a clean pipeline you've greatly reduced the possibility of that.

M: Any other comments now from the panel on any of those comments? Okay. "How is pigging frequency determined for, first, wax build-up, and, second, debris build-up?"

Gary Smith: I think that operators of pipelines have to have some intelligence with regards to the operation of the pipeline and the product that's in it. With regards to debris build-up, we look at again the material that is pigged out of the line, we look at sometimes we can actually find material in the receivers just from flows that have gone through it. Sampling points, low spots, valves--there's a number of different ways to be able to see if you've got any kind of debris in a pipeline and whether or not you know where it is and how thick it is is a different story.

In regards to wax, from a chemical standpoint you should know that you've got a waxy content crude and that you've got an operating environment such as temperature that will allow this to build up. And I think that you have to have some common knowledge--some intelligent knowledge of your pipeline to know that you have those conditions available.

When and where to start pigging? I would recommend that if you have a pipeline that you know is going to have any kind of evidence of wax or scale, that you pig the pipeline on an extremely frequent basis until you have a good idea of the deposition rate of this material and then you can adjust accordingly.

M: Okay. Any other comments from the panel? Okay, Gary, thanks.

Wonderful job. Let's have a hand for Gary.

APPENDIX B

MAINTENANCE PIGGING CONFERENCE PRESENTATION 2

GREATER KUPARUK AREA FIELD PIPELINE MAINTENANCE PIGGING

DAVID NEWMAN OF CONOCOPHILLIPS ALASKA, INC.

ABSTRACT OF PRESENTATION 2

Greater Kuparuk Area Field Pipeline Maintenance Pigging

Speaker Name: David Newman, Corrosion Engineer

Company Name: ConocoPhillips Alaska, Inc.

Website URL: http://www.conocophillipsalaska.com

Type of Business: ConocoPhillips is the third-largest integrated energy company in the United States and second-largest refiner in the United States based on market capitalization, oil and gas proved reserves and production. Worldwide, of non-government controlled companies, ConocoPhillips has the fifth-largest total of proved reserves; and based on crude oil capacity, is the fourth-largest refiner.

The Greater Kuparuk Field on Alaska's North Slope uses a system of pipelines to economically transport oil, gas, and water to processing facilities. Cleaning pigs are used during routine maintenance of pipelines. Tracking Key Performance Indicators is an important element for managing a successful pigging program. Topics of discussion will inlude:

- System overview;
- Current practices;
- Types of pigs used;
- Pigging Rationale;
- Key Performance Indicators (e.g. solids removed, bacteria activity, etc.).

TRANSCRIPT OF PRESENTATION 2

As I'm introducing David, he will be setting up his materials in here. David Newman is a corrosion engineer for ConocoPhillips here in Alaska. David has 25 years of experience in the oil industry at Prudhoe Bay and Kuparuk, and is currently working in the Kuparuk chemical and monitoring program. And maybe he has a cat story, too. I don't know. We'll see.

If you want to just take a moment to stand up and stretch, this might be a good idea to do that. Please don't leave the room because we're going to get started here just momentarily. Just one stretch, that'll be great. For those of you who are standing in the back, if you would like to have a chair we have the front row open. To eat here at lunch time, you need to buy a ticket. And we were hoping all of you would do that as you registered and hopefully most of you have done that. If you don't have the little card, if you didn't prepay, and you don't have a little card to present at the door you can buy a lunch ticket out at the registration desk. Is that correct, Jim?

Jim Lagomarsino: I don't think so anymore. I think lunch is not available anymore.

M: Yes. I should have read what you gave me. I apologize. So, if you don't have a ticket, there's a McDonald's right down the street. All right. Without further delay, we turn it over to you. Thank you.

Dave Newman**:** Good morning. I'd like to talk this morning about the greater Kuparuk area maintenance pigging program. That program is mainly performance-based, and we will be talking a little bit about the monitoring of that program.

The Kuparuk Field is comprised--the greater Kuparuk area is comprised of the Kuparuk Field, Carn, Melt Water, Tobasco, and Palm in addition to the Kuparuk Field. The Kuparuk Field is comprised of 47 drill sites and over 1100 wells, 640 of those wells are production wells, 490 injection wells in the field. There are 530 miles of insulated pipelines and over--approximately 225 cross-country lines.

Through the lines in the field every day run approximately 600,000 barrels of produced water, 250,000 barrels of seawater and over 300,000 barrels of crude oil--pipeline spec crude oil.

The layout of the Kuparuk operation--which is on the sea coast between Alpine and Prudhoe Bay--the production starts at the well heads and flows to the drill sites. The drill sites are associated with the CPFs, of which there are three central production facilities. At the central production facilities, three-phase flow is separated. The water being ejected--that at the drill sites--the oil--sales oil moves to Pump Station 1 and the gas is used for fuel gas and is re-injected. Seawater is taken in from the Beaufort Sea at the Seawater Treatment Plant, and distributed to the CPFs for injection as part of the water flood project.

Service types of the pipelines at Kuparuk can be broken down into five different types. Production lines carry oil, water and gas, three-phase flow, from the drill sites to the central production facilities, the CPFs. Wet oil lines carry production that is not the first-stage separation at CPF-3 to CPF-1 and CPF-2. Water injection lines are lines that carry the produced water and seawater to the CPFs for injection at the drill sites. Seawater pipelines distribute seawater from the seawater treatment plant to the CPFs and to Alpine--to the Alpine Field for injection. And the common carrier lines which carry sales oil from Alpine to CPF-2; CPF-2 to CPF-1; and CPF-1 to Alyeska at Pump Station 1, including Noman Point production.

Looking at the water injection lines in a little bit more detail. Those water injection lines carry produced water and seawater from the CPFs, separated from the three-phase production. That water is used for enhanced oil recovery or water flood. Cross-country lines with water injection lines are generally pigged on a monthly basis. The pigging program on the water injection lines has been standardized across the field to a standardized pig configuration which is cup/disk/brush on the pig. And then each one of those water lines is pigged in triplicate each time it is pigged.

Seawater lines--the main seawater lines distribute seawater from the STP--the 30-inch water distribution line to the CPFs for injection. That distribution system network is pigged weekly, general and biocided weekly. This is a photo of the STP right on the Beaufort Sea.

This drawing shows the water distribution system at Kuparuk. The light blue line is the seawater line from STP to CPF-3, CPF-2 and CPF-1. And the darker lines are the produced water injection lines that radiate out from the CPFs to the drill sites for injection.

As you'll notice, there is also the seawater line that runs to Alpine from CPF-2 area.

At Kuparuk, as I mentioned, the Alpine production sales oil line enters the Kuparuk from carrier lines at CPF-2 and along with the sales oil from CPF-2, travels to the CPF-1 area and then to Pump Station 1. We have wet oil lines from CPF-3 to CPF-2 and CPF-1.

The frequencies for pigging the lines at Kuparuk and the types of pigs, other logistics as part of the pigging program, are based on the field and industry experience, the type of fluids that are handled in each of the lines.

The lines and the pigging that's done on these lines is also based on known conditions and histories of those lines. Whether they've been used for seawater or produced water, mixed water conditions. Whether the pigging returns for the total suspended solids are increasing or decreasing over time, the composition of those solids. Whether they're bacterial in nature or reservoir solids, or scale. Bacterial activity in the pigging returns, the biocide performance if those lines are biocide in conjunction with the pigging, and then the relevant inspection data. Whether there is known corrosion activity taking place in these lines.

The actual pigging operation is handled by pigging crews that are dedicated to each CPF. And instead of using field site maintenance personnel, we have dedicated pigging crews for each facility that handle the launching and the receiving of all the pigs. We also have a dedicated sampling crew that does the sampling of the pig returns for each of those pigging routes to monitor the effectiveness of the pigging runs. The scheduling of all the pigging in the field is done by the field site lead technician, based on operational considerations. And we have a pigging coordinator that works out technical issues and seeks new and improved pigging techniques. And we have a maintenance planner--or maintenance planners--that keep our pigging supplies stocked and maintained.

To keep track of all the pigging that we do, and we do over 120 pig runs in our lines a month, we have an automated tracker. And this tracker is set up on our data system that allows easy input and puts the information from each pig run into a database. So we can keep track of that information over time and use it for our performance monitoring.

Part of this monitoring program that we have, we track pigging solids, where samples are taken on each pig run and those submitted solids is measured and the total amount of solids is calculated from the solids removed. The pigging effectiveness is based primarily on the solids removed and on most of the pigging runs we do analyze the solids, and this is a general schematic of a pig launch and receiver system.

The bacteria tracking that we do with the pigging returns is done using serial occlusion. We are mainly looking at sulphate producing bacteria in those returns and the biocide and pigging frequency rates are adjusted based on the bacteria composition of pigging returns.

Here is a picture of serial occlusion technique for monitoring bacteria in the units. This is a picture of an actual pig launcher with the door to the launcher on the left there and all of our pigging facilities launchers and receivers are inside buildings. That's kind of due to the weather as well as we have secondary containment provided by these facilities being in buildings.

This is a picture of a pig receiver and a tool for removing the pig. The barrel of this pig receiver was 14-inch and the line is a 12-inch line.

This is a picture of a pig, urethane disk, cup disk pig that had been used, a less aggressive pig. This is a picture of a scraper pig that we would consider using in some of our pipelines that do develop paraffin over time.

This is a more aggressive cleaning pig that we have pretty much standardized for use in our water injection lines with the brush, two brush sections. And in some of these we include a magnet because we use magnetic pig sigs on some of our lines also.

And so overall the program is monitored using key performance indicators. The pig runs on a schedule based on the number of pigs and the number of lines that are to be cleaned over a period of time. That is kept track of by our pig tracking system. The total solids, the composition of those solids are monitored for each pig run. Bacterial activity is monitored, and the biocide residuals are measured to determine whether we need to adjust the biocide rates in those particular lines. And then mitigation of corrosion, which is determined by inspection techniques on each of these lines.

So, in conclusion, we think we have a good, robust pigging program at Kuparuk, and use key performance indicators to monitor that program. And thank you.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: Do we have any questions from our panel? Yes, please.

Dave Hart with Pioneer Natural Resources: ConocoPhillips' most recent drill sites over the past five years you talked about Carn, Palm, Melt Water and Alpine CDs have employed pig valve with the launching and receiving. Have you found any limitations on the pigs available to run due to that reduced length available for you?

David Newman: Yes, as a matter of fact, we are employing some--a number of pig valves. And we have found that in certain configurations of pig valves, the valves are slightly damaged by running compression pigs through them, and so there is a limitation there. In general, the operators like using them apparently because they are easy to remove the pigs from and so, you know, we are still evaluating those valves. But, yes, there are some possible limitations.

M: Does that answer your question? Other questions from the panel?

Tom Johnson, BLM: Of the various lines that you have, which require the most aggressive pigging cycle?

David Newman: By far the water injection lines do require the most aggressive pigging. And we do have corrosion inhibitor in all of those lines and biocide. So most of those lines are pigged on a monthly basis, and that is being monitored with the program that we have set up.

M: Does that answer your question? Okay. Other questions from the panel? Yes, please.

Cathy Foerster, AOGCC: Have you noticed any impact on your corrosion program and your pigging requirements due to the changing reservoir fluid characteristics through the introduction of your satellites and from maturing your EOR and water flood?

David Newman: That's a good question. Okay, I guess we can break that down. As far as the changing of the fluids from the different reservoirs that are being produced from--we do see additional solids production from some of these reservoirs. We also see additional or increased paraffin in most of these, some of these satellite reservoirs. And those do require, you know, different types of pigging. As far as corrosive fluids, we haven't noticed any increased corrosiveness of the fluids from any of the reservoirs.

M: Does that answer your question? Okay. Yes, please.

Bill Flanders, of DOT: How do you determine the time for performance evaluation. Is it done on an annual basis? Is it done after every pig run? How often do you determine your performance criteria to determine if the frequency should be adjusted?

David Newman: In fact, we have--it's kind of more of a monthly type evaluation. We have increased the frequency of pigging and biociding on our seawater distribution system based on bacteria that we have found in that line. Although when we smart-pigged that line this summer, we found very little damage, very little corrosion. And so we are continuing on the increased frequency of pigging on that particular line, but it's a continues process we evaluate the on pretty much continues, but at least once a month.

M: Thank you does that answer your question?

Tom Johnson, BLM: What's the driver of your maintenance pigging program--is it prudent business practice or Federal and State regulations?

David Newman: It's actually mainly integrity preservation, or asset preservation, I should say. And to keep these assets operating and to prevent the leaks and spills as well as to maintain the production.

M: Does that answer your question? Okay.

Cathy Foerster, AOGCC: You said you analyzed solids composition on most of your pigging runs? Why would you not analyze the solids composition?

David Newman: Generally, unless the service of the line is changing over time and it has the same fluids from the same reservoir flowing through it and we have seen no change in the composition of the solids, then we might not analyze the solids on every pigging run. But, usually it reaches a kind of a steady state on most of these lines.

M: Does that answer your question? Any other questions? You guys over here are allowed to ask some.

Sam Saengsudham with ADEC: Dave, do you have lots of T's to deal with when you pig the lines? T's.

David Newman: T's in the lines?

Sam Saengsudham: Yes.

David Newman: Yes. As a matter of fact, the configuration of the piping system does include T's and so there are sections of the lines that the pigs have to be able to bypass.

Steve Sauer, BP: Real, real quick. Do you track each pig?

David Newman: Yes, sir.

Steve Sauer: And magnetic pig-tracking work for you?

David Newman: Where we have used it--actually we use a magnetic pig stick, so we're not tracking the pig the entire length of the run. But we have got suggested some of these styles of pig sigs and the nice thing about them is that they are portable. And so you can move them from location to location and use them wherever a pig is coming in instead of having them permanently located.

Steve Sauer: From a sub-sea perspective, the magnetic did not work out for us very well. The ROVs tend to trip them off.

David Newman: We have had fairly good luck with them. It's not 100 percent.

M: Does that answer your question? We all wish we were with Mardi Gras. Other questions? Okay, thank you very much.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

David Newman: Okay—The common carrier lines at Apline and Kaparak are pigged on a monthly basis. Widow oil lines are also pigged monthly. The line from Kaparak to Pump Station 1 also maintenance pigged monthly. The line from Alpine to CPF2 and the line from Kaparak to Pump Station 1 has been smart pigged several times over the lasts five years.

M: Okay, anything to add from the ConocoPhillips side or BP?

Bill Hedges from BP: It is quite well known that on our oil transit lines our pigging frequency varies from every two weeks to every fifteen years. As Maureen mentioned this morning, the two weeks was through the more wax depositions, so that's why that was pigged every two weeks. The other oil transit lines that leaked on the western side of our operation, we pigged it clean in 1990 and again in 1998, so after eight years we removed virtually no debris at all. So we were sort of comfortable with an 8-year frequency. In hindsight that was totally wrong. And I think one of the lessons for me is you maybe can't talk about pigging frequency. It needs to be, as mentioned just now, you probably need to spend more time looking at what we get and making decisions on when we should run the next pig.

M: Any other comments from anybody on the panel? Next question: "How is pigging effectiveness currently calculated?"

David Newman: As I mentioned, we use the performance indicators which include the total amount of solids or debris removed with each pig run, the bacterial content of the material that is removed with each pig run and then if the line is also biocided, the residual biocide that's detected at that point in the system. And, so, those are the main ways that the frequency is determined.

M: How about effectiveness?

David Newman: The effectiveness?

M: Of the pigging operation. How do you calculate that?

David Newman: Well, it's a good question. I guess ultimately it's based on the inspection of pipe. And whether the line is remaining free of damage. So, inspection is the ultimate way that we can determine that. So, if the corrosion--if there's any active corrosion and corrosion rates are under control, then the pigging program is effective.

M: Any other comments from either ConocoPhillips or BP on this problem? Anything from the government panelists? Any comments? Yes, please.

Bill Hedges: I just wondered if you ever used a pressure drop on the line to check the effectiveness of any program? You have the pressure builds up and builds up and you see the line flex in the drop of pressure or friction pressure in the line?

David Newman: Actually we really don't have that much solids build up. We really don't have a pressure build-up problem, at least on the water injection lines.

M: Yes, please.

Bill Hedges: I haven't seen that technique used here in Alaska. We certainly use that technique in Trinidad for the lines that have a significant quantity of debris. I would agree that you need a large quantity of debris in order to see a significant pressure problem. We don't I suppose have that here in Alaska.

M: Any other comments?

Steve Sauer: I am aware that on some of the Gulf of Mexico they have done some mathematical models of predicting the amount of wax with pressure drop, and they adjust their cleaning frequency based on a certain pressure drop and then they correlate that with the amount of solids they brought in.

M: Okay, David, this is going to be directed to you, but obviously when you hear the question it applies also to our agency representatives here. "Does the state or industry maintain an inventory of all (oil, gas, water, etc.) pipelines on the North Slope along with pigging histories that can be used by regulators for analysis."

David Newman: I don't know whether they maintain that inventory of the lines. And as far as I know they--we have not provided information on specific pigging operations.

M: Okay.

Sarah Pate: On our common carrier lines we are reporting to the regulators on those, but beyond the common carrier lines, the field lines, we don't provide that information.

M: Just so everybody in the audience is familiar with the difference between the two types of lines, can you explain the difference between an infield line and a common carrier line?

Sarah Pate: Infield lines are the ones that go from the well heads up to the factory facilities, and the common carrier lines are the ones that take the sales crude so that's the line for us from Alpine to the crude processing facility down at Pump Station 1 and those are DOT regulated. And the other line is not under DOT jurisdiction.

M: How about from the government side? Any comments, please? This is my friend, Sam.

Sam Saengsudham: To answer this question, I would say not yet. Well, not yet that I'm aware of, but since now we are going to have flow line regulations become effective hopefully soon that might be one of the options or a starting piont.

M: Okay. Any other comments from the government side?

Bill Flanders: The federal side. The regulated lines--we keep an inventory of all regulated lines and of all smart pigging runs. The maintenance pigging runs we do not.

M: Okay. Other comments from anybody on the panel?

Sam Saengusdham: I'm not sure about mileage to mileage as far as the common carrier line, but we do have thousands of miles of flow lines. I'm assuming the question is regarding all lines.

M: Okay. Another other comments from the panel? Yes, please.

Bill Hedges, BP: Yes, we maintain an inventory of all our pipelines, whether they can be maintenanced or not, whether they can be intelligent-pigged or not. Some lines can be maintenance pigged but the pig launchers and receivers are not big enough to hold intelligent pigs. We keep records of when they maintenance pig and when they smart or intelligent pig.

M: Any other comments? Yes, please.

David Newman: As I mentioned this morning, we do have a database of all the pig runs that we do as well as all the lines and their configurations as far as whether they can be maintenance pigged or smart pigged.

M: Any other comments? Okay, next question. "How long has Kuparuk had their pigging program and practices in place?"

David: The maintenance pigging program at Kuparuk has been in existence for more years than I have been working in this position. So, for the last--I just speak from my position working in this area for the last year. And the pig program's been in existence during that time. And I possibly Chuck could help us better.

M: Would you speak up just a little bit, please?

Chuck Knecht Conoco Phillips: I have been in operations for almost 20 years and it's evolved ever since I've been in operations.

M: So we have a one-year and a 20-year. Can I hear more? It's been a long time. Okay, from your perspective, how effective has it been? Any of you from ConocoPhillips. How effective has the pigging program been?

David Newman: At least in the last year it has evolved to the point where we are monitoring and adjusting the frequency based on that monitoring. And are continuing to improve and to change the program as seen from the results of the monitoring program.

M: Okay. How about a BP perspective? From your side? How long has it been around and how effective has it been?

Bill Hedges, BP: There may be better people than myself to talk about how well. Many of the facilities were designed for pig launchers and receivers, so I'm going to speculate --I really don't mind if someone says I'm wrong here--I'm going to speculate that pigging in some form or other has been around since the beginning of the field. I think as conditions have become more corrosive or fluids have changed to produce more solids, or become more waxy or paraffinic, I believe programs have evolved to where they are today. We do pigging because we know it's very effective, and I would say pigging is an important tool in your toolbox of control techniques, particularly for corrosion. And where we've done it it's been very effective.

I would also say there are many of our lines that we have that naturally flow at very high velocity and are self-cleaning. And we don't need to pig them. They operate under multi-phase flows and we don't need to pig them. We have good control of those lines. But here we need to pig, we do pig and it's a very effective tool.

M: Okay. And then one last question for you, David. "What can you do with the water pigging returns?"

David Newman: In almost all cases those are injected down into the injection wells, so all of the solids which can vary from 100 pounds to, I think, 1000 pounds per pig run, are injected down the hole. If we're pigging a line that we know has a lot of extraordinarily high amount of solids, we may pig to a tank, but for the most part it is injected down into the injection wells.

M: Okay. How about BP?

Mark Peterson: Basically the same situation. We have just recently gone to a program where we are going down all the primary usage tanks. And the same thing, we had one down for awhile because of a bad launch door or receiver door and it so it was down for quite awhile for both of those tanks to get cleaned up so we don't take a chance of plugging up an injector.

M: Other comments? Panel? Okay. This is actually a question now that is going to be directed at BP and I'll invite any of you to chime in and, David, if you want to add anything then please do. "Does BP have a pig-tracking database program similar to Conoco? And, if so, please give a general description of the BP pig-tracking program."

Mark Peterson: Yes, we do. We have a pig-tracking that's been in place since Mr. Dan Hale (?) here in the audience I think started it way back in the late 80s, early 90's. But, yes, we do have it. We track it. We have quite similar parameters than they do. I would be interested to talk to someone at Conoco. But ours is in an older database, keeping it updated, but it works really well and we enter all of our maintenance pigging runs into that and ILI runs so we can have good historical data.

M: Before I ask if anybody else has any comment, would you introduce the gentleman in the audience again?

Mark Peterson: Mr. Dan Hale. He is actually at Valley Point now.

M: Dan, can you just stand up for a second?

Mark Peterson: He's more or less one of the originators of the pigging program on the west side and now he's doing the same thing over at----

M: The reason I asked you to stand up is that if anyone has a question they want to check with you during the break, there's the man to talk to. Okay? Okay? Any other comments on that? From anybody from BP or ConocoPhillips?

David Newman: I would like to mention a few features of our program the fact that it is automated it's very easy to use and the operators or the pig crews can enter that information. It collects the current flow rates, collects velocities, so all that goes into the database and there's a place for comments for the relative condition of the pig, whether there were any problems with the pigging line, so all that data is collected and it's very easy to use.

M: Okay. Any other comments from anybody? Okay. Once again, this is a question directed at BP representatives. If you could field it and if ConocoPhillips has anything to add, that would be great. "Has BP been finding large quantities of debris?" (other than cats, I hope) You had to be here this morning, I guess, huh. "Large quantities of debris in their pipelines that have not been maintenance pigged for awhile?"

Mark Peterson: I think we've experienced pretty much typical debris. We've been helping on the--our crew, primarily I guess for the audience--our pig crew primarily worked on the west side recently. We've now expanded to the east side of the field to help with the oil transit lines. We haven't experienced really high amounts of solids on any of these lines that we've recently done. Yes, we have found cats in our lines, or caribou, for that matter--we do tend to find a lot of files and welding rods, so it is there other than your normal pigging material.

M: Okay. Any other comments from BP representatives, or anything from ConocoPhillips? Please.

Steve Sauer: From a mission perspective, when we push out some pry bars and you said welding rods and other debris that the installation team has left behind, it just makes it a little more challenging sometimes. Some of those pry bars cost $1 million by the time we get them out.

M: Any comments? Please.

Jim Lagomarsino: Just to elaborate a little further on some of the pigging returns that we see. As the line velocity slows down and the temps of the oil cooled a little bit, we are seeing an increased buildup of sediments in the bottom of the pipe. And this is kind of a natural occurrence. It happens. So, like I said earlier, when we pigged the Flow Station 2 to Flow Station 1 line, we saw significant volume in returns--but about just a little bit over what we projected. We just completed a campaign between Flow Station 1 and Pump Station 1 at Alyeska and we got significantly less than we projected. And we're constantly analyzing these returns and the patterns we're seeing. But the contributing factors are that it is not unexpected to see returns in a pigging situation. We had scanned the lines in advance with some gamma ray technology to determine how much sediment buildup was in the line, ranging from zero to a couple of inches for the most part. So, it wasn't an abnormally high level of sedimentation in the line. It is what you would expect to see in an oil transit system.

M: Other comments, please?

Bill Hedges, BP: On the run that Jim was just referring to, we were very fortunate to have the cooperation of Alyeska to let us use one of their tanks, so even though the solids were not as many solids as we expected, we actually fed them all into one of Alyeska's tanks to avoid putting any of our solids into the trans-Alaska pipeline. And now that's done we are going to clean those tanks to help to remove the solids.

M: Any other comments? Okay. I have two more questions and they seem to be related, so I will probably ask both of them. If I covered it with the first one we can move right through. "So far we have seen discussion that seems to center on single-phase lines. How has the introduction of three-phase change the discussion, or are the different considerations in terms of the pigging program tailoring it to the three-phase type of line?"

David Newman: The three-phase flow compared to the sales oil or water. Generally we have more gas and potentially more solids in it. And possibly more corrosive and requiring more frequent pigging of the lines. I think from a corrosion standpoint, I think those systems require additional attention as far as corrosion monitoring because of the nature of the fluids. With some systems it is more difficult to get that corrosion that are distributed throughout the system with the solids in the water.

M: Other comments? Please.

Mark Peterson: Just from a pure pigging standpoint, a three-phase line is quite a bit different than a single-phase line in the fact that you have a massive--say an oil line--you have a massive fluid traveling along. You can travel a pig at a fairly slow speed and it will be constant. A three-phase line is somewhat more dangerous in the fact that it will surge. Three-phase lines are more difficult to run a small pig through because you need to keep a constant speed on the pig. You can run a smart pig at a very slow rate as long as it is a very constant rate. If you start surging it, it's when you are going to have problems with data. Normally you get the speed spurts. And the same thing with maintenance pigging, if you--the pig will push some material into a corner and it will build up over the gas behind and then the pig gets a surge and it will actually run up over the material, leaving it in the pipe.

So there is considerations in three-phase lines. It is a bit more difficult, and just be more consideration you need to think about before you do it.

M: Any comment? Bill?

Bill Hedges, BP: I would just agree with David that for us that the multi-phase lines are generally more corrosive than oil transit lines. And you have high pressure gas in them and a lot more water. And that's typically where we've focused most of our corrosion programs. Mark just said there are a lot more risks involved in pigging, but we do it when we need to do it. I would repeat what I said earlier and that sometimes these lines run under conditions known as slug flow. And the very fluid regime itself actually acts as a kind of pigging for the line and will sweep out certain amounts of solids and debris from the lines. Sometimes you don't have to pig them.

M: Other comments? Just a little bit of a nuance in the last question that we have on this, "How directly applicable are single-phase pigging practices in multi-phase environments?" I mean are there significant changes, differences? ConocoPhillips, BP, anybody?

Chuck Knecht: With three-phase flow, obviously it's again what was mentioned here. In the operation of these you are faced with slugging. I don't know the particulars but obviously you have to factor in the gas rate versus the production rate. It is definitely different.

M: Any other comments, please.

Mark Peterson: Just one clarification to that. We have one of the largest three-phase lines probably in the world that we know of on the North Slope, and that's a 36-inch line which is a very large three-phase line, so we deal with a wide range of situations and even these three-phase--our three-phase lines, again, are not difficult. It's just a matter of setting up for it, doing it properly.

M: Okay. Other comments from the panel? Okay. We have now finished the first two of the discussions.

Greater Kuparuk Area
Field Pipeline Maintenance Pigging

Maintenance Pigging of Pipelines Conference

October 19, 2006
Hilton Hotel
Anchorage, Alaska

ConocoPhillips
Alaska, Inc.

Kuparuk Field

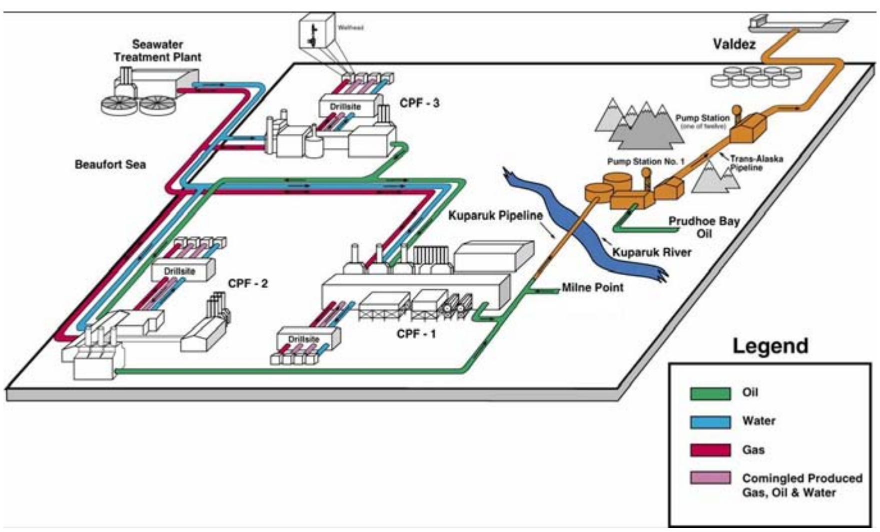
- 47 drill sites
- 1,100+ wells
- 640 production wells
- 490 injection wells
- 530 miles of insulated pipelines
- ~225 cross-country lines

ConocoPhillips
Alaska, Inc.

Kuparuk Pipelines

Pipeline Conference
October 2006

Greater Kuparuk Operations



Pipeline Conference
October 2006

Kuparuk Pipelines

- **Production Lines** – Oil, water and gas three phase flow lines from drill sites to CPF's.
- **Wet Oil Lines** – Production fluids from first stage separation at CPF-3 to CPF-1 and CPF-2.
- **Water Injection Lines** – Produced water and seawater from central production facilities (CPF's) or gathering centers to drill sites.
- **Seawater Pipelines** – Carries seawater from Seawater Treatment Plant (STP) to CPF's and to Alpine.
- **Common Carrier Lines** – Sales oil lines are from Alpine to CPF-2, CPF-2 to CPF-1 and CPF-1 with Milne Pt to Alyeska Pump Station #1.

Water Injection Lines

- Water injection lines run from CPF's to drillsites – produced water and seawater
- Cross country water injection lines generally pigged monthly
- Pigging program standardized field wide with cup/disk/brush pigs
- Each pig run consists of three separate pigs

Seawater Pipelines

- STP to “CW Skid” 30 inch seawater transfer line generally pigged and biocided weekly
- “CW Skid” to CPF-1 24 inch and CW to CPF-2 24 inch seawater lines are generally pigged weekl

Pipeline Conference
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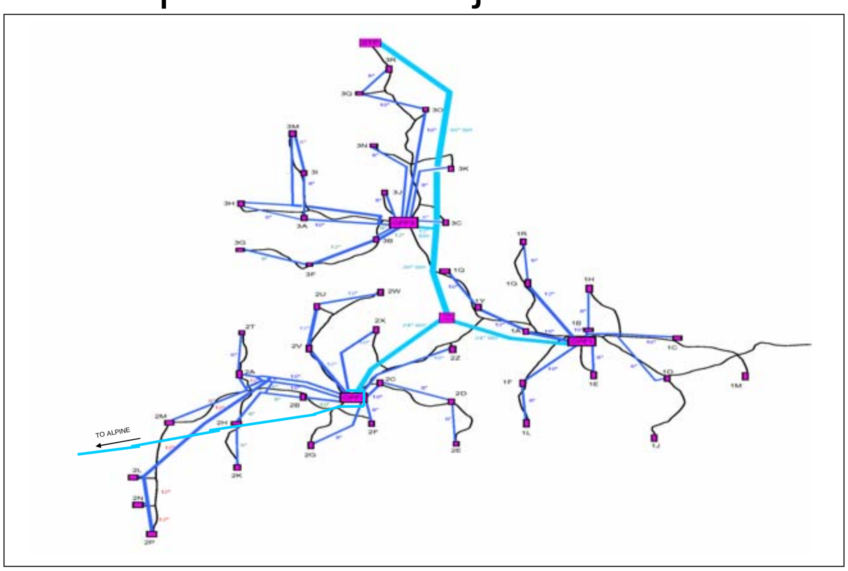
Kuparuk Water Injection Lines



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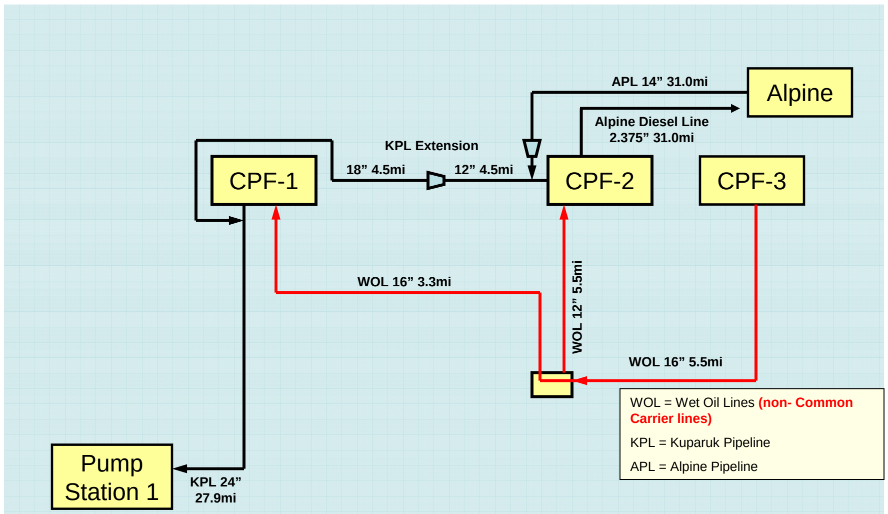
Common Carrier Lines & Wet Oil Lines



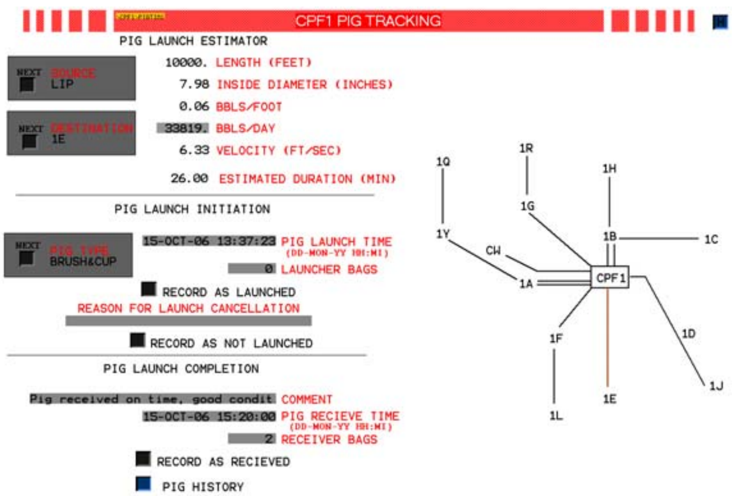
Maintenance Pigging Rationale

- Pigging frequencies, types of pigs, and other logistics are based on field and industry experience, type of fluids handled and measured performance such as:
  - Known condition and history of the line
  - Pigging returns or total suspended solids
  - Composition of solids
  - Bacterial activity
  - Biocide performance
  - Relevant inspection data

Pigging Operation

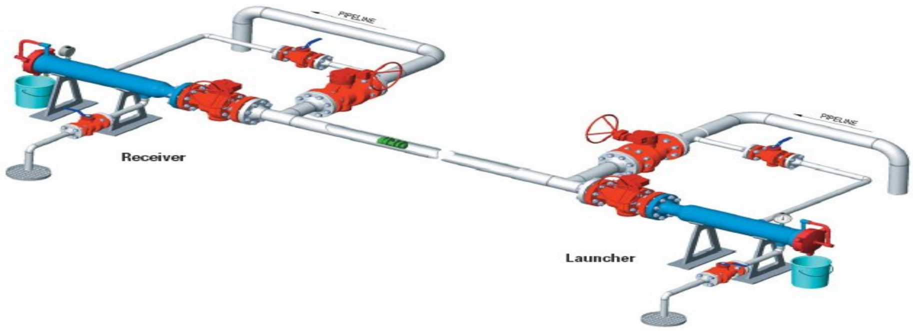
- Pigging crews handle all pigging at each CPF
- Drill Site Lead Technicians schedule pigging at each CPF
- Pigging Coordinator works technical issues
- Maintenance Planner orders and keeps pigging parts supplied

Pigging Operations Tracker



Tracking Pigging Solids

- Water injection line pigging returns are monitored for Total Suspended Solids (TSS)
- Pigging effectiveness is primarily determined by total solids removed
- Pigging solids analyzed for composition



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Tracking Bacteria

- Monitoring of viable bacteria in pigging envelope such as Sulfate Reducing Bacteria (SRB)
- Biocide rates and pigging frequency are adjusted based on bacteria activity

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Pig Launcher

Pipeline Conference
October 2006

Pig Receiver

Pipeline Conference
October 2006

Cup and Disk Pig

Pipeline Conference
October 2006

ConocoPhillips Alaska, Inc.

Scraper Pig

Pipeline Conference
October 2006

ConocoPhillips Alaska, Inc.

Combination Cup-Disk-Brush Pig
(More Aggressive Cleaning)

Pipeline Conference
October 2006

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Pigging Program Key Performance Indicators

- Pig runs on schedule
- Total Solids and Composition
- Bacterial Activity
- Biocide Residuals
- Mitigation of Corrosion

Pipeline Conference
October 2006

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APPENDIX C

MAINTENANCE PIGGING CONFERENCE PRESENTATION 3

RECENT AND NEAR FUTURE ADVANCES IN MAINTENANCE PIGGING TOOLS AND TECHNIQUES USED TO CLEAN PIPELINES

DEREK CLARK OF BJ PROCESS AND PIPELINE SERVICES COMPANY

ABSTRACT OF PRESENTATION 3

Tools and Techniques Used to Clean Pipelines

Speaker Name:	Derek Clark, Business Development Manager USA and Latin America Region
Company Name:	BJ Process and Pipeline Services Company
Website URL:	http://www.bjservices.com/website/pps.nsf
Type of Business:	BJ Process and Services provides a range of commissioning, precommissioning and maintenance services to the Process and Pipeline Industries including online and offline cleaning of pipelines and smart pigging services to verify pipeline integrity.

This presentation deals with the issues of cleaning pipelines, which have been in service but have not been subjected to a regular maintenance pigging regime. It highlights the range of cleaning solutions now available and, through consideration and evaluation of these solutions, emphasizes that the way to tackle cleaning is through a systematic and structured engineering approach. The presentation also discusses pipelines which are not piggable and offers a range of techniques, some of which are field proven, others that are not, that could be adopted for this situation. This presentation looks at pipeline maintenance pigging from the standpoint of the service provider. Topics of discussion will include:

- Factors that determine cleaning techniques and tool selection
    - Given conditions and parameters associated with a pipeline or pipeline services
    - Type and volume of material to be removed
    - Reason for cleaning (level of cleanliness)
- Cleaning Techniques and Tools
    - Mechanical Cleaning
    - Chemical Cleaning
    - Cleaning with Gels
- Other Potential Techniques

TRANSCRIPT OF PRESENTATION 3

Derek Clark is standing here right to my right. He is the business development manager of the USA and Latin America Region, for BJ Process and Pipeline Services Company. He is a mechanical engineer with 35 years of experience in engineering, including five years as an educator. Derek has worked the last 18 years in the oil and gas industry gaining hands-on practical experience and has been involved in project design and engineering, operations, supervision and global product line management. It's all yours, Derek.

Derek Clark**:** Thanks. Thank you very much for the opportunity to address you today. Just to re-introduce myself a little bit. My name is Derek Clark, I am with BJ Process and Pipeline Services, and we are a division of BJ Services Company.

I want to talk to you today about recent and near future advances in maintenance pigging tools and techniques used to clean pipelines. I would like to kind of split this into two areas. In the first part of this speech, I'm going to go through all of the parameters and considerations that you take in account when you are designing a cleaning train or coming up with a cleaning solution.

I will split this into three areas. That's the conditions and parameters associated with the pipeline itself; the type and volume of the material to be removed; and the reason for cleaning or the required level of cleanliness.

I'm going to deal with that first before we get onto the cleaning techniques. I'm not going to go over these individually. There is a number of parameters associated with the pipeline itself that need to be taken into consideration. Some of them are fairly obvious and some of them a little more subtle. But, to a varying degree we need answers to all of these before we can come up with a pigging solution. And what I'm talking about here is lines that have not been pigged for a considerable period of time. I'm not talking about routine maintenance pigging that's conducted day in and day out, week in and week out. I'm talking about the condition where you've got a line that hasn't been pigged for an extended period and you've got a lot of unknowns about what's in that system. Some of these are internal to the pipeline and some of these external.

This is really the critical point for me--the type and the volume of the material to be removed. With us it's incredibly important when you are thinking about the situation where we don't really know what's in the pipeline, we don't really know what the material is, we don't really know how these materials adhere to each other, or adhere to the pipe wall. Before we can get into this designing a solution process, we need to fully understand what these materials are. Getting a sample to the lab is an absolute critical part of this for us. In fact, what we really like is to actually get a section of the pipe, complete with materials in it, so we can work with how they are bonded to each other. And normally, we are talking about more than one material in there and how they're bonded to the pipe wall.

We typically split these into two types of materials: organic and inorganic. And the organic are obviously mostly hydrocarbon residues that come in all shapes and forms and degrees of softness and hardness. Inorganic which are typically more of harmless products like calcium carbonate, corrosion products like iron oxide or sand or other well finds. The solution that we come up with depends entirely on the type of material in the line and the volume of material in the line.

I just want to put this up there. This is very typical of what you're going to find in a pig track once you do in mechanical fitting once you run a pig through the line. And as we go through this, and we talk about some of these solutions, it's important to go back and remember what this looks like. This is a wax with sand and a little bit of rust in it. And you can see the consistency of that. You imagine you have sixty miles of 24-inch that has this material adhering to the pipe wall. You start getting to scale the problem that you may have in front of you.

So, reasons for cleaning: For lines that are already in production there is basically three main reasons for cleaning. The easiest for us to deal with is efficiency gain, which is really a non-critical situation where you just want to increase the throughput through the pipeline or reduce the energy required to push the product through the line. In most cases then everyone's a winner. If you take some debris out of the line then it's in a better condition than when you started.

For inspection runs, I wasn't sure if everybody in the room knew what an inspection tool looked like. This is an MFL tool. Although they are relatively fast and they are adapted to go into environment, you can see this is essentially a scientific instrument. It really can't cope with large amounts of debris in the pipeline. So it's important that you get the pipe clean to a level that will allow this tool to run through the line.

The success rate in these runs is about 80 percent. One in five of these tools fails. I think about 80 to 90 percent of these failures comes from debris in the pipeline. So it is extremely important to get that line clean.

One of the difficulties that we have is that there isn't an international standard for cleanliness in a pipeline. It's always a matter of some debate between the inspection company and the operator of the pipeline whether the line's clean enough to allow an inspection to go through the line. There are international standards for surface roughness, for surface perforations, for hydraulic systems, but there isn't standards you can go to that will tell you how clean the pipeline would be. And obviously it would be quite a difficult thing to do.

This is potentially one solution to that. This is a deposition tool. These aren't readily available on the market just now, but I think they're going to be introduced fairly soon. And for those of you who know what a caliper tool is, this is basically a weakly sprung caliper that has 32 sensors or fingers around the pipeline. And as this cuts through the debris in the line, the sensors come out and record the deposition profiles. So you can use this tool to measure how much deposition you have in the line before and after cleaning and it may lead to some kind of specifications for cleanliness.

So that pretty much deals with all the variables associated with the cleaning specification. I'm going to deal now with cleaning techniques. And I split this into four: Mechanical cleaning, chemical cleaning, cleaning with gels and other potential techniques. And the other potential techniques is the request of the organizing committee to look at a situation where a line is unpiggable and see what kind of solutions are out there for unpiggable pipelines. That's what we call "dead legs." That is a leg where there is no flow through the pipeline, and obviously you can't run a pig down there.

Mechanical cleaning can be described as using a solid object to scrape and push pipeline trash and debris from the line. In most cases this is some form of pig, although spheres and other objects have been used. And a pig can be displaced with wide product or other displacement medium such as water, air or nitrogen. For pipelines that have a significant volume of debris, or where there is a potential of significant flow restriction, a procedure known as progressive pigging is adopted. I think Gary mentioned a little bit about that area.

Actually this involves confirming some level of flow communication through the pipeline and then gradually increasing the aggressiveness of the adopted cleaning regime until the desired level of cleanliness is achieved. Progressive pigging can be applied to any of the cleaning techniques that I'm going to discuss here. Basically all that is saying is you really don't know what you can get through this pipeline, or how you can pig for a considerable period of time. You know, you've got a decision to make about the first device you put through that pipeline. What you really are trying to avoid is this situation here. This is one of the disadvantages of pigging. And that's where you're pushing a pig through the line, and especially if you've got softer wax or debris. You tend to get debris building up in front of the pig until you get to the stage where the displacement pressure to move that pig forward is no longer available. Either you punch out of head pressure, or you are out pressing the line where you can't go above. And this is the biggest news in knowledge of mechanical pigging. It's a great device for removing material from the pipe wall, it's a great device for breaking material up. But it isn't the best system in the world for removing debris out of the pipeline. Especially if you have significant volumes of debris in the line.

One of the other issues, which is kind of the opposite of that, it depends on the nature and the scale of debris that you have in the line, is that pigs have a tendency to ride over the debris in the line as well. And you can take a pig out of the line and it can basically remove very little material and the pig's in great condition. But the line can still be full of a significant amount of debris.

I want to talk a little bit about enhanced cleaning brushes. Again, Gary mentioned this earlier. Over the last few years there has been a move towards what we call enhanced cleaning. For a long time, people were using these single leaf cantilever brushes that are very easily deflected. The brushes themselves are very easily deformed. And if you run these every day or once a week, they are reasonable tools for taking debris out of a line. But if you've got a lot of hard scale in there or if you've got a significant amount of scale in there, these are not the best tools--not very efficient. There seems to be a consensus of opinion now that the best way is to direct the amount of these brushes onto the mandrel of the pig. And put all of the flexibility into the actual wire brushes themselves. So they've got a real elastic memory, and they're forcing themselves onto the pipe wall.

And that's a far better system than having something that is easily deflected and bounces off and misses a lot of the debris. This is the inline pit master. This is the one that Gary was talking about that is good for the microbiological influenced corrosion or most commonly known as pits. These are--this one's got a little more flexibility than most of the enhanced brushes. And the tips of the brush is designed to scour out the pits in the wall. I think this is a tremendous designed brush and a great solution for getting at pits.

In addition to having brushes, there are a number of other designs of enhanced cleaning tools. Gary showed you some of these earlier in his presentation. These are extremely useful tools, and utilization of these has allowed cleaning of pipelines to a level which would previously have been unobtainable. And that's the kind of good news. The bad news is that you've got to be extremely careful when you run these pigs.

This is a picture of the internal diameter of a 36-inch pipeline that has some very particular problems and I know this line reasonably well, and it has some quite hard scale in it and for a long time it's had a very aggressive cleaning pig run through it. And with great success. And this is to run inspection runs. I'm not exactly sure what happened, but they obviously got a little bit aggressive when they were running the tool and I don't know if you can see clearly here in the picture here or not, but these are longitudinal scratches along the length of this line. This is over 100 miles of pipe that was damaged with this tool, so they're good tools, they have their place, but you have to be extremely careful on how you apply them.

I thought I would share this with you. We have a five-year maintenance cleaning contract in West Africa with a major oil and gas company. And this is a kind of a unique solution to the particular problem they have. We normally wouldn't do maintenance pigging like this--it's something the operators would do themselves. In this particular occasion they have a tremendous problem with wax fallout, an incredible amount of sand in the lines; in a very short period of time they accumulate enormous volumes of material in the line. This pig here--and this is a slightly better picture of it--there is no driving disks on this pig whatsoever. It's a production pig; it goes through with fluid in the line, and all we do with this pig is we break up the debris that's in the line. It's back to how these materials adhere to each other and how they adhere to the pipe wall. And breaking that up is the secret to removing material from the line. You can see this particular one has got a circular brush in the back. It's sized not to touch the pipe wall, but just to remove the debris. So all we do with this here is we just loosen up the debris and we follow up with a gel train--I'll come to that in a minute--and gel technology really is the best way to move large volumes of debris out of the pipeline.

I have a number of slides here, just some typical mechanical pigs. This is the single-leaf production pig that's normally run through the line for an enhanced cleaning situation or situation where you haven't pigged for a number of years. This is not a particularly attractive pig. I need to show the range. This is untypical of how they come out.

The pig on the left-hand side is a little bit of an interesting one. It's what you call a jetty pig. And part of the line fluids bypass through the center of the pig. And it kind of fluidizes or puts the area in front of the pig in a slight area if turbulence. If this pig loses velocity and stops, the DP builds up over the pig and it tends to jet out from and can be an aid to removing differential pressure that accumulation of debris that I showed you in that other slide.

I'm moving on to the chemical cleaning now. And I'm going to discuss three types of chemical cleaning: cleaning with solvents, reactive chemistry and surfactants. And as Gary said, you always run solvents or surfactants or any of these chemicals between batches of pigs. So this doesn't do away with pigs, we just use them in conjunction with pigs. Solvents are typically diesels or alcohols or napthas--any kind of hydrocarbon material. And what we typically do is, we've got a sample in the lab, we will run some solubility tests and determine which is the best solvent to use. And this is a typical example of a lab test we did for a client of ours who gave us an actual section of pipe. It's a little difficult to see, I really don't have a decent tool picture, but if you look here, right in this area in here, this material here is adhering to the pipe wall along the circumference and all along the length. So you run some solubility tests, get the best solvent for this particular debris, and all we do is we fill up the line. We don't run a pig through the line. And we leave it in there for about two minutes to reflect contact time that we would get in the field and then we simply drain it off. You can see how effective, how clean this line here is all around the circumference.

There are some disadvantages with solvents. Solvents are not particularly effective in the temperature ranges you typically find in a pipeline. They are better at high temperatures. Contact time is also an issue. You need to have enough time to work. They work by dissolving the light end hydrocarbons. That's really what they're effective for doing. And they're really great to sludge up again, so you have to use it in conjunction with mechanical pigs and you still can have issues with handling a large amount of debris. But solvents can and are an excellent solution for cleaning pipelines and we use them on a fairly regular basis.

Reactive chemistry is interesting. To be absolutely frank with you, it's not something we would normally recommend in a pipeline. We use this chemistry all the time. We use it in utility boiler fitting, we use them in refineries, petrochemical plants, but we use it in a controlled situation where the volumes are smaller, you can see one end to the other basically. If you are going to treat 10% hydrochloric acid into your pipeline and you're going to run it 100 miles, it takes a certain level of bravery.

It has the same kind of problem, in fact all the chemicals have the same problem, but none of them are as effective at temperature ranges. They are all better at higher temperatures. The problem with solvents--one of the things you can do in reactive chemistry--is you can increase the concentration so that there is usually a solution around the temperature effect, so if you are going from 10% hydrochloric to 50% hydrochloric, the fluids tend to get really nervous. I guess the message here is, it has its place, but be extremely careful in how you use this.

Surfactants are surface-acting agents. This is like chemical Velcro. It's kind of like solvents, but solvents dissolve. What surfactants do is they hold it in solution, and again it's the light end hydrocarbons. So, it really just depends on the debris you have in the line, it gets back to knowing what you've got in the line, whether or not solvents or surfactants are the best solution.

It is a little bit easier on disposal side sometimes when solvents are hard to handle. With a slight caveat, that they are solution-form so a lot of the debris is held in solution, and it could take a little bit of time to break that. But, again, an excellent way to wash out a pipeline.

Cleaning gels: First of all, to describe what gels are, this picture on the end shows the typical consistency of a gel. Gels are highly viscous general liquids that have a number of applications in the lifecycle of a pipeline. In terms of pipeline cleaning techniques, the primary application is in the transportation of unwanted material out of the pipeline. The gels typically do not clean a pipeline but are a very effective way to increase the efficiency of the cleaning process by removing large volumes of materials from the pipeline.

All of the gels that I'm going to talk about now are either water-based or hydrocarbon-based. In other words, we take water and in a very simple process we turn that into a gel. Simply you will make jello with gelatin to do that and one or two other ingredients crosslink for those of you who understand gel technology. Or we take diesel and gel diesel, or even crude oil and gel up crude oil.

This is a typical gel cleaning train and it's moving across the screen in this direction here. Typically you will have a leafed pig that is standard bidirectional pig, and you will have the same two standard bidirectionals on the back and three brush pigs in the middle. The separator gel does exactly as the name suggests. It is used to separate the debris-pickup gel from the line product both in front and behind of the train.

All types of gel can pick up and transport debris with varying degrees of efficiency. And I'll show you that in the next slide. Debris-pickup gel is usually a high viscosity shear thinning plastic. It is high viscosity at low shear rates and high yield strength, which ensures that the debris remains suspended even if the gel is stopped for a long period. That's a pretty important characteristic. Basically what all that stuff means is this is not a Newtonian fluid. It does not behave like water, it has different characteristics and we use these characteristics to our advantage to remove large quantities of debris out of a pipeline.

Typically we will design these to carry one pound of debris per gallon of gel. But we know and have experienced that will hold up to ten pounds of debris per gallon of gel. If you just think about physics and acid test, that gives you a tremendous comfort range there. This is a very forgiving system. If you miscalculate the volume of material you've got in the line, this system will handle up to ten times more than--you know, if you outline a factor of ten, it will still handle all that material.

Just to confuse everybody, this is actually running--it's a sig pig train. This is from an actual job. And it's actually running backwards--when we did this graphic for some reason it switched around. What we do is when a pig train comes in, we take debris loading samples from various stages along the train. And as you can see here the debris loading matched against the 12,000 foot length of this pig train. What it really shows if you think about it, it is almost reached here. If this line had more debris in it, we have all the spare capacity in here. You can see how forgiving the system is. Clearly pig loading can be put all the way along the back and whatnot, and all the way up there filled with debris. So it is a tremendously forgiving system.

We removed 56,000 pounds of debris from this system. And by its traveling the results of loading from the back of the train, we've calculated that there was another 2-1/2 thousand pounds remaining in the line. And that's another big advantage of this system--that you can calculate how much debris, or least estimate how much debris you have left in the pipeline from the loading in the back of the train. There really isn't another cleaning mechanism that will allow you the ability to do that.

Once you get the gel into the receiving side, to handle that gel we have break-up chemistry. So we can break this back to its original component parts. That means if it's a water-based gel, you can handle the water quite easily, it's biodegradable. There is no environmental impact to using this technology. If you gel up crude, then you can simply re-inject that crude into your fluid system.

But also, on completion of the gel run, we want to break and wash in the pipeline. The process of break and wash is to remove any residual gel from the pipe wall. And that has the added benefit normally of taking out that last 2-1/2 thousand pounds when you run the break and wash. Again, the break and wash is run through between a couple of batching pigs or at least a couple of pigs.

This is a typical gel train, and you've seen a lot of pictures today of dirty pigs.

I'm going to touch on this towards the end, but recovered volumes. A large amount of debris is removed from the traps and you've seen pictures of people digging in traps to remove debris. This is a very, very small percent of the volume of material that's recovered. Whether it's a gel system, whether it's a mechanical cleaning system, or any other cleaning system you find, you still have to handle these solids. And I'm going to touch on how you would typically do that.

A lot of that solid comes back in your product itself and you need to come up with a mechanism that's going to protect your parent facilities from all that debris coming back again.

Our clients don't always believe everything we say, and sometimes they come behind us and they check what we've done. This is a--throwing up these examples where we took out 56,000 pounds and then we followed up with break and wash and took out another 2-1/2 thousand. The client took two samples of the line where he estimated to have the most debris in the line. We cut a couple sections out and these are the pictures of these sections. And this shows you how clean you can get a pipeline. And it's huge. This is a very, very different pipeline. I think in total there is about 60,000 pounds of debris which was taken out of that particular line.

So, now I'm going to talk about other potential techniques. And I was asked to cover the situation where you have a valve, single valve and into a dead leg. And I don't know any of the other details about it. I'm kind of confused about the question. So, I kind of dug around and found a bunch of potential solutions for that that are out there. I'm sure there are some others, and we really need to get more details of the problem before we can discuss it even further easily. But things that I know that have been used in that kind of situation and have worked are coiled tubing snubbing units or hydraulic workover units. Then there's a couple of techniques that we have that you wouldn't really use in a line that's full of product. But are used in dirty spools, and that's clear shot and retrojetting. There is a very interesting technique called exothermic reactions. And I want to touch on another couple of points that I thought you might find interesting.

So, coil tubing. Available here in Alaska, standard coil tube equipment. As the name suggests, this is steel tubing that's coiled on a power drill and it can be fed or spooled into the pipeline through a special type unit that injects that tubing into the line.

One of the disadvantages of coil is that as it implies, as you spool into the line it takes a helix. It takes a spiral in the line. The way the pig works is you inject solvent through the coil as you are displacing it. And you have a jetting head in the front of the coil and you basically jet material off the wall.

You've got to pull that coil back, so there is a limitation on how far you can displace a coil to remove it out. And with a standard oil field coil, and this is about 1-1/2 inch diameter coil, you get about 6,000 feet--maybe 8,000 feet into the line and then you're going to have to bring that back.

There are systems out there that will go up to about 15,000 feet, so you can get a reasonable distance out in the line. Another disadvantage to a dead leg situation is all you're really doing here is you're moving material from the pipe wall and not removing material from the pipeline.

I don't have a show on the snubbing unit. But, again, I'm sure they're available here. It is not a service that BJ provides. But hydraulic workover units, or snubbing units, they work a similar way to coil. But they use drill pipe. They won't go around the bends, but you can extend them out to about 20,000 feet. And both coil and hydraulic workover units are used for hydrate blockages, and I know of at least one line that we've worked on this year in the Gulf of Mexico where we used the hydraulic workover unit to basically cover a line that otherwise would have been abandoned because it was completely blocked with wax.

I won't go into the details of clear shot or retrojetting. These are techniques normally used on spools that are dirty.

I talked a little bit about exothermic reactions. This is another one of these--this is from the last solution we're going to go to in the list of solutions. This is where you chemically heat. So you put in either--there's a couple of ways you can do this, but basically you are using chemistry to produce heat. And you can get up to 150 or more degrees Fahrenheit in this. And the intent is to spot it over an area where there's a build-up of wax, and there's very little flow through there. This system is used successfully. I have seen photographs using this system, as far as I know on a fairly regular basis on subsea flow lines that have a particular wax problem and they are rather than in your flow line. Okay, we'll go with the exothermic reaction.

I want to briefly talk about how you handle solids both in the gas line and an oil line. And typically what we do in gas pigging operations is we'll put a couple of temporary gas filtration units in parallel and we'll run the gas through our filtration system to protect the permanent facilities. And, you can see, as one side gets plugged up you switch to the other side. You punch out and we remove the cassettes and simply switch out the dirty filters for the clean filters.

And obviously for liquid lines or for lines where you are going to have three phases, we can put a three phase separator. These separators have pretty big capacity, or we can put a liquid in a liquid separator for situations where you are just removing solids.

So, in conclusion, maintenance pigging systems should always be designed into new systems. If you are building a new system, make it piggable. For existing systems, collect all the data and if you can possibly get us a section of pipe, get us a section of pipe and just do a lot of risk analysis. Design it to minimize risk to people, the environment and your pipeline. If you can reasonably make a system piggable if it isn't already piggable, then make it piggable. That's usually the best solution. Don't experiment with your pipeline.

Fit the problem to the solution, not the solution to the problem. There are lots and lots of clients who come to us with some preferred method for cleaning the pipeline. It's often based on their own experience in the past and not necessarily based on the problems they have in the line. So, it comes back to fully understanding the problem you've got in the line, all the materials that are in there and how they adhere to each other, and how they adhere to the pipe wall.

Lastly, pipeline pigging is not rocket science, but it is science and it is engineering, and I would encourage you to use them both.

Thank you.

TRANSCRIPT OF QUESTIONS FROM THE PANEL

Moderator: Okay. Any questions from the panel? Yes, please.

Mark Peterson, BP: On a waste management level on the gels, you say you break them back down. Do you run them into some type of separator when you break them down so you take the solids out?

Derek Clark: Not always. Sometimes we do through a separator, sometimes we do just through the back tanks.

Mark Peterson: Okay, so you run through there, break the solids out and then re-inject that crude.

Derek Clark: Exactly.

M: Does that answer your question?

Mark Peterson: Yes.

M: Any questions from the panel? Yes, please.

Chuck Knecht, ConocoPhillips: You talked about the deposition film? Is that available now?

Derek Clark: I think I expect we will probably discuss that on November 13 when we come up here. It is not exactly available now. I don't know where it is in the cycle, but it's almost available is how I would put it. I also don't know what the gamma range is either.

M: Does that answer your question? Other questions from the panel?

Sam Saengsudham: Based on what you've seen, what is the most common reason for an existing line not being piggable?

Derek Clark: For the line not being piggable? You mean some characteristic of the pipeline? I don't know what the most common--there is a number of reasons why it may not be piggable. It may not have launchers or receivers on it, it may be a bend problem--the really tight bends are an issue for us. It may be a valve problem. There is just any number of issues. Multi-diameter could be another one. I don't think there's any one specific common reason. I guess my point I'm making is if you just fit pig traps to make it piggable, then fit pig traps. It may cost you a little bit of money but it's going to be worth it in the end.

M: Another question from the panel?

Dave Newman, ConocoPhillips: Do you have any experience with gelatin pigs?

Derek Clark: Yeah, that's gel pigs as opposed to gels. Yes, there are a few areas where we run gelatin pigs through the line, not necessarily for a cleaning purpose but maybe a meltdown of a system or some other system. But I wouldn't typically use them for cleaning. It's kind of a separate product that's for solvents that is certainly an option and has been done.

M: Does that answer your question?

Dave Newman: Well, yeah. And then a follow-up. Have they been run in conjunction with the lines that don't have launchers or receivers?

Derek Clark: Yeah. It can be, but we still need access to the end of the line. It doesn't have to be a launcher or receiver but it does need to be isolated and recovered. You don't need an extended valve to do it.

M: Does that answer your question? Other questions from the panel? I have to ask Cathy. To ask her questions. I haven't picked her on her now. She is raising her hand.

Cathy Foerster: I was noticing the complexity and I assume that length associated with some of your multiple staging of gels and pigs. Have you found any instances where the operators have to go in and redesign, or redesign the pig launchers and receivers if that reinstall new pig launchers and receivers as technology advances is that a common or a difficult thing?

Derek Clark: No, not really. As long as you've got a valve beside your pig traps and you can isolate to load and launch you can do it in stages

Cathy Forester: But they haven't been getting so long that they exceed the length of your launchers and receivers.

Derek Clark: No because these systems I am talking about use individual mechanical pigs then the rest of the material is pumped in so we displace one pig by pumping in the fluid and then launch another pig and another pig it doesn't take an extended pig to do this.

M: Does that answer your question?

Cathy Forester: Yes it does, Thanks

Jim Lagomarsino, BP: You mentioned basically of the lack of standards associated with the ILI type of inspection. Is BJ currently working with others in the industry to establish standards to give us something to work towards?

Derek Clark: No. We're certainly not. And it's a very difficult to come up with a standard to follow. Because it's sight unseen really. And I personally believe the best option is that deposition roll-out tool, or some other tool to measure the level of depositions that is in there. And then from that we can build a standard. But right now you don't know what's in there, so how can you judge to make a standard or not. Because you can't see it. You have to measure it and right now that measurement tool is not available.

M: Does that answer your question?

Jim Lagomarsino: Just a follow-up to that. And also the ability to clean the line will affect the effectiveness of an ILI tool to do its job. Lack of standards, therefore, pose additional risk I assume to the ILI success.

Derek Clark: Absolutely. I agree. Like I said, one in five--I think it's an industry number--one in five inspection runs fail. Around about 80 percent of these fail because of debris in the lines. So, you know, it's a big issue and it needs to be addressed.

M: Does that answer your question? Okay. Other questions from the panel?

All right, Derek. Thank you very much. Appreciate it.

TRANSCRIPT OF QUESTIONS FROM THE AUDIENCE

Derek Clark: Okay what are the major risks to people, to the environment and to operations?

M: Right, on pigging operations.

Derek Clark: Wow. That's a pretty broad question. I don't even know really where to begin here. Any time you deal with pressurized fluids, particularly gases, it is a great hazardous situation, needs to be carefully controlled. And in pigging operations you would be running at reasonably high pressures, not tremendously high, but reasonably high. So I'd say that's really the most hazardous condition, just working in pressure, and I mean pressure on the lines. So you've just got to make sure that anytime you work on the line that the pressure drops and it's safe to open that to pick it out.

In terms of environment, and really just a spill or a catastrophic fuel leak on the line in some stage, I don't think that's happened more than a handful of times during the pigging operation where the line has failed catastrophically. But I guess it has happened sometimes, and that would be the biggest environmental impact that I can think of.

And operations itself, and easily the biggest risk would be if you managed to get the line blocked by getting a little bit too aggressive too quickly. Especially if you got multiple pigs in the line and that can get pretty ugly in a hurry.

M: Other comments from members of the panel? Yes, please.

Gary Smith: For those of us who do this for a living, we travel around the world and see pipeline operations and plants everywhere. And in a lot of cases it's not as organized and safety-conscious and environmental-conscious as Alaska. There are very few incidences in this industry. There's not that many hurt people, there's not that many explosions, there's not that many spills when you take into consideration the miles of pipe, and the amount of people that are involved in it, and the sheer fact that you're dealing with explosive products. So I think it's actually a merit to the industry that the environmental and personnel issues are not any worse than what they are. It's more dangerous driving a car out here than it is working around these pipelines or around pigging operations.

M: Any comments?

Jim Lagomarsino: Yeah. I'd like to kind of mirror those remarks. We're with a group that doesn't travel around very much. We are in a static environment up there, but at the same time we take our accountability and our responsibilities to our people and for the protection of the environment very seriously. We go through very detailed procedural development review processes before we initiate a pigging campaign. And we look at the safety of our people, we look at job safety analyses, task hazard analyses, and do all the steps you do to think through the job very thoroughly to ensure the protection of the people and the safeguard of the environment. None of us wants anything to happen to either one of those.

So it's something that I know BP and Conoco and any other crude operator, we all follow the same basic rules and protocols of analyzing our job very well beforehand and executing methodically to be sure they are safe at the same time.

M: Any other comments from the panel? Okay. Next question. "What are the techniques for measuring debris volume buildup in a pipeline?"

Derek Clark: It is extremely difficult to do. I don't think there really are any techniques up there for measuring the debris volume in a pipeline. The kind of classic measurable that you have is that suddenly you have an increase in pressure in the pipeline, and it's always extremely difficult and important to know whether it's a very short, restricted blockage or a longer slight blockage. And there's no real way to know that. You just have to come up with a solution to the problem that takes into account either of these possibilities.

If you are talking just, say, 60 miles of 24-inch pipe, for example, you're talking about an affected area somewhere in there that's only, I don't know, several hundred yards. It's very difficult from the information you get either side of that pipeline instrumentation-wise to know pressure flow to determine what the scale is. It's a very difficult problem.

M: Any other panel members want to comment? Please?

Jim Lagomarsino: I can't speak to any of the multi-phase lines or anything, but on the oil transit lines we've had recent experience with on the Slope with BP, we've used a number of techniques to try and establish what the sedimentation was in the pipeline.

We are not restricted by pressure, we have got back-pressure control on Pump Station 1, so if we were to pull pressure restrictions off, we wouldn't really see anything. So, we had a number of data points to work with up there. We had some coupon cuts in the pipe itself to take some little pieces out, and see if there was any buildup of calcium carbonate scales, something like that.

We also did some external, I think I mentioned earlier, gama ray scanning of the line in representative places where we thought we would have sedimentation to identify how prevalent that condition was. And based on that, we basically developed our estimates of what we expected to get from the line. And we also developed our approach to progressive pigging to safely and efficiently move that sediment out of the line and process it in conjunction with Alyeska pipeline.

M: Other comments from the front table? Next question. "During a cleaning pig run some material is carried downstream past the pig track. How do you measure the volume of the material removed by the pig?"

Derek Clark: Typically in a mechanical cleaning run we wouldn't. There is no real need for us to measure that volume. There are several ways you could do it, but all of them would involve putting in temporary equipment to kind of bypass to so you protect the parent facilities. And as I discussed in the presentation, with gas lines we put in inline filtration system to take care of any kind of solids that were coming down the line to protect the inline filter. And on three-phase lines you can use three-phase separators or just a liquid--you could use a straight liquid separator. But we typically don't even measure that. If it's a gel tree, we can and do measure the volume that's in there. But if it is product trapped, or if it's solids trapped in the product, then from a service provider standpoint the operator may want to measure that, but we wouldn't measure that.

M: Do we have some operators at the table? Any comments?

Dave Newman, Conoco: The technique that we use typically is that we monitor the flow in the line as where we are expecting the pig to be approaching the pig receiver. And basically we visually determine when the pig debris and the load arrives, and we take a representative sample of that pig return envelope. And then measure the solids content on that and calculate based on the flow rate the estimated amount of total solids removed.

There is certainly a lot of other factors involved with getting an accurate value of total solids. You know, how the receiver is handled and how many pigs have been run in succession, but it is possible to get a good estimate of the total solids removed.

M: Anybody else have anything to add? Yes, please.

Mark Peterson: We at BP, we do a real similar process. Our database has points in it for when the dirty water, particularly water during the water line when the dirty envelope starts there and we get solids and we put those points in time-wise and then we calculate from the flow rate how much solids there are. Is that run sample perfect? No. But you get a good representative sample and we can go back historically then and see if we are increasing or decreasing to know if we're having problems with increasing solids.

M: Other comments from the panel? Thank you. Okay. Derek, I'm going to give you a quote back from your talk. Hopefully this is an accurate quote. According to this question you said, "Solvents are always run between batching pigs." Okay? "What are batching pigs?"

Derek Clark: They're just a method of containing the really separate the solvent out from the product in the line. It's a matter they're running a slug liquid in the line to keep it segregated from the product in the line as needed to be introduced.

M: Okay. I have a couple more things apparently you said that needed to be clarified by this questioner. "What is an MFL tool?"

Derek Clark: That's a magnetic force linkage tool. That's a inline inspection tool. It's just a particular type of inline inspection tool. I think if you come back November 13th you'll get a better answer than that.

M: Okay. Will we get a better lunch?

Derek Clark: I don't know. You tell me.

M: Lunch was good. I'm just---- Okay. What is an ILI tool?

Derek Clark: Inline inspection. It's just an acronym. This whole business is full of them.

M: And then one last question, clarifying. "When gel is used as a cleaning agent is the pig train connected together?"

Derek Clark: No. I'm not really sure what you mean by that question. The entire pig train consists of individual mechanical pigs that are separated by different gel slugs, so they are not physically connected. But, I mean, it's just called a train because they're continuous.

M: Were there any other comments by anybody on the panel on those? Thanks for clarifications. Okay. Once again for you. "Please clarify ease of disposal of, first thing, solvent cleanouts which often can be pumped into produced oil after solids are removed."

Derek Clark: Yeah, I mean, it's very hard to answer that question. I mean a lot of these things depend on the specifics of the case. And the selection of the solvent for any particular case is going to be based on the product you have in the line and the material you are trying to dissolve. And it is the reaction of these that needs to be considered. And the disposal is a large part of the selection process. You know, that's all taken into account beforehand. It's not done after the fact. So you need to make sure that if you can use a solvent that you're not going to have a disposal issue. That is engineered before and not after.

M: Okay. Once again, "In terms of ease of disposal surfactant cleanouts which are difficult emulsions to break?"

Derek Clark: Well, that depends entirely on the surfactant. I mean, some surfactants are difficult to obviously break, and some are aren't. The most successful pipeline surfactants are actually very poor surfactants in the static condition. They are very good dynamically, so when they're moving they are very good muscle power. They're a very good surfactant. But once they're stopped they actually break out quite easily and there are a number of surfactants out there that are specific to pipelines.

M: And, finally, from the same questioner. "What type of cleanouts"---- No, I'm sorry--"C-H-E-L-A-N-T-S?"

Derek Clark: Chelants.

M: Chelants. I knew it. I just wanted to see if you knew it, Derek. "What do you recommend? EDTA or NTA?"

Derek Clark: That's just a type of reactive chemistry. We typically use EDTA's in utility boiler units. To my knowledge, we have run them as a company in flight plans. I just use that as an example of a reactive type chemistry that is used to clean pressure vessels, really utility boilers.

M: Okay. We have people at the table that actually have to dispose of materials after doing various types of pigging operations. Anything you want to add in terms of ease of disposal on any of those questions that were handled? Anything at all?

Okay, next question. "What is the status of pig---- There's a word here that I'm not sure I've---- plugging?

Okay. "What is the status of pig plugging technology? Isolation for cutouts and that sort of thing?"

Derek Clark: Okay. I can answer that. There is a technology out there that uses either a remote or a tether tool that you can position in the line and then deploy to provide a local isolation and there are a number of companies--or at least two that I know about--that I think provide it, but I think there is an exhibitor here today that has that technology and TDW has an isolation tool. I don't know if anybody in the audience wants to speak about that, but it's a relatively common used technique that has no real function in the cleaning process that I'm aware of. Although that is just another reason to clean the lines sometimes is to clean them for an isolation tool or plugging tool.

M: Next question. "What kinds of exothermic reactions are used in source water?"

Derek Clark: In source water. The only exothermic reaction that I know that is typically used in pipeline cleaning applications is a petrobrass system that is used down in Brazil. They have a particular problem with wax dropout in flow lines and they have a system where they basically mix a couple of salts together and they start to heat up, and it's a race against time to pump that to the location where the blockage is and it basically melts the blockage. Like I said, that's probably a solution of last resort for me, but it is a technique that's actually being used to clean pipelines.

M: Anybody else have anything to add? Next question. "Please provide further details on BJ's typical preparations for cleaning both crude and natural gas transmission pipelines. Can you estimate the leadtime required for cleaning a pipeline in Alaska?"

Derek Clark: Wow. To answer the first part of that question, it really depends how much data is available to us. We like a--I tried to emphasize, we need a complete understanding of the system. We also like to get a section of the pipe complete with a sample *in situ* so we can understand how everything is bonded together. Obviously that takes a little bit of time to get. It is very difficult to answer unless you have a specific something. In terms of Alaska, we actually have a base in Kenai and we are in the process of mobilizing a pipeline disposition training forum. This is really not even at our school. Our business is kind of split in two between process services and pipeline services. And we are, like I say, in the process of transferring people into Alaska so our response time depends on the size of the job and nature of the job. Pretty darn quick if it's a small job, would be my answer.

M: Anybody from the industry side have any comments on that in terms of your experience? Yes, please.

Mark Peterson: Typically, BPA is the preferred vendor for the MFL tools on the west--well the east side of Prudhoe Bay. And typically they send a crew up just short of doing the run, and we normally have the line clean, be it 1, 2, 5, 7, 10 runs--you know, whatever the line is, whatever the service is. And then they're there in time to run the gage tool.

Their gage tool is set up to measure the hard points of the tool in turns, and they can tell--we make sure that they're available when we pull that out so they can tell if they have any stage plates on the bend. So they can tell if the tools are hitting a hard point and sticking in the line. Anyway, so they are there to see that and then they run the MFL shortly thereafter. So it really is a wide variety. But we normally try to keep, when we know a run's coming, we try to keep it clean well in advance so, you know, the vendor's not there to run it. It shortens up the time to get the line clean.

M: Okay. Any other comments? ConocoPhillips, anything to add? Okay. Next question. "What would a typical cleaning program to prepare a pipeline for abandonment and demobilization take?"

Derek Clark: It depends on where the line is. Whether it's a subsea line, whether it's a land line. It depends on what the product is and it depends on what the acceptable practice in that particular area is. For example, it's not uncommon in subsea lines to simply flood them with seawater and let them corrode in place. Then there are other places in the world where you actually have to remove the pipeline completely for abandonment, and other places where they are snaked up. So it really depends on the local regulations for abandonment. In terms of the preparations for that, well it's pretty much the same as any other job. You take a hold of it, you need to engineer it, and the rest is there to the lead times.

M: Does anybody else have any comments on that? Okay. I have two more questions. Are you up for them?

Derek Clark: I'll try.

M: Okay. "Owners/operators appear to be passing responsibility of their pigging programs off to their vendors. Vendors are clearly staging their---" They say, "staging they pig per their contracts." I'm a little bit confused about exactly what that is.

Tim Terry: Stating. Stating.

M: Okay. "Vendors are clearly stating they pig per their contracts. Comment on how your CP programs ensure vendors comply with your code and lease requirements." This would, I think, probably be directed at the companies as well.

Derek Clark: I think it best if they answer that particular question. I don't see a trend in companies taking up responsibility for maintenance pigging. I mean, as a company, we only have one maintenance pigging contract globally. And I don't know anyone else that has one.

And that's because of very special circumstances in that location. So, I don't really think they are doing that. I think they best answer that themselves.

M: Please.

Dave Newman from ConocoPhillips: We do all of our own maintenance pigging at Kuparuk and the only services that we hire vendors for would be for inline inspection and smart pigging. But all of our maintenance pigging is done by our own crews and internally inhouse.

M: Any comments from BP, please?

Mark Peterson: Same thing with BP. We have BP operators that are charged with the pigging program and we have some contract help, but it's all done inhouse. With one exception. We had one crew come up recently for a very large campaign we had going. We had--but they were worked directly with us, under our supervision.

M: Any other comments? Yes, please.

Becky Libby: I think we as vendors are seeing companies hiring us out to prepare them for internal inspection more so than taking over the pigging operations. We have been involved in cleaning programs, but that's to prepare the lines for internal inspections, not for taking over the maintenance program.

M: Okay. Any other comments from the panel? Okay. Last question. "With lower flows, oil temperatures will more than likely drop. This will result in more wax deposition. Any idea what this will do regarding the frequency of cleaning pigs and how often they will need to be run?"

Derek Clark: I think it will increase them, but it depends again on the conditions, is the short answer.

M: Okay. Please.

David Newman: Actually, as fuels age, the water production generally goes up and the temperature goes up if production acid water cuts increase. So, if there is a paraffin problem and the water rate is going up and the temperature is going up, then it will somewhat counteract that. In Kuparuk we have very little paraffin problems, but do find that as the water production increases, the temperature goes up.

M: Any other comments?

Mark Peterson: Kind of equitable, same comments--that we don't see a lot of paraffin problems on the BP side. We have one fuel site that makes a little bit of paraffin, and then, of course, Northstar, Badami fields also make paraffin, but the main production facilities and the lines there don't show a large amount of paraffin.

M: Okay. Any other comments? Okay. With that question we finish the third round of questions.

Recent and near future advances in maintenance pigging tools and techniques used to clean pipelines.

Derek Clark
BJ Process and Pipeline Services

Maintenance Pigging Conference
October 19th 2006

Hilton Hotel
Anchorage Alaska

Organized by
Shannon and Wilson on behalf of the
State of Alaska

Recent and near future advances in maintenance pigging tools and techniques used to clean pipelines.

Introduction

The intent of this paper is to address the issue of recent and near future advances in maintenance pigging tools and techniques used to clean pipelines.

The paper considers circumstances where regular maintenance pigging and cleaning techniques cannot or have not been applied. However the paper develops the argument that where and when reasonably possible the most effective cleaning operation is the regular displacement, trap to trap, of an effective cleaning pig and that as a consequence maintenance pigging operations should be considered a fundamental requirement of any pipeline design basis.

Pipeline cleaning techniques vary with: -

- **Given conditions and parameters associated with a pipeline or pipeline systems**
- **Type and volume of material to be removed**
- **Reason for cleaning (required level of cleanliness)**

Developed solutions tend to be specific to a given situation; there is not a "magic bullet" that can be universally applied to any given pipeline or pipeline system. That is not to say that innovative solutions and techniques are not available but rather that the development and application of these techniques is usually for specific sets of conditions.

In all probability similar conditions exist in Alaskan Pipeline systems and some of the tools and techniques presented here today will have application in Alaska, it is equally likely that some of the issues in Alaska will in themselves require the application of yet to be developed solutions and techniques.

In addition the paper considers the advantages and disadvantages of the various techniques and tools presented. The paper, as requested, also advances some potential solutions for the situation where there is a requirement to "launch and receive from same barrel for dead leg areas".

The paper does not specifically deal with issues of economics or the time available for the cleaning operations, both of which are usually major factors in the decision making process.

Pipeline conditions and parameters relevant to cleaning operations

The following list is not exhaustive but rather is indicative of the number of variables affecting the selection of a particular cleaning technique: -

Internal

- Product
- Diameter
- Length
- Number, style and radius of bends
- End terminations
- In line valves
- Interconnecting pipe work
- Connecting pipelines
- Pigging history
- Differential pressure history
- Maximum allowable operating pressure (MOAP)
- Design pressure
- Compressor/pumping stations
- Pipeline in or out of service
- Internal coating

External

- Topography (ground profile)
- Environmental sensitivity
- Population density
- Ambient Conditions
- Disposal
- Location

Due consideration of these variables usually considerably narrows the available options for cleaning.

Type and volume of material to be removed

Fundamental to determining a cleaning strategy is fully understanding the nature of the problem. This can be very difficult to do, from the perspective of the scientists who operate the analysis laboratories at BJ Process and Pipelines I can tell you that they will always want not just a sample, but a section of pipe complete with adhering sample. Obviously this is not always possible to obtain. However for any of the available chemical solutions, getting a sample is imperative.

Safety and Environmental issues associated with materials found in pipelines must always be reviewed and considered, for example where there are Naturally Occurring Radioactive Materials (NORM) or pyrophoric material.

One way to categorize the materials typically found in pipelines would be: -

- Organic
    - Paraffin wax
    - Paraffin wax and asphaltene
    - Other Hydrocarbon residues
- Inorganic
    - Sodium Chloride
    - Calcium Carbonate
    - Magnesium Hydroxide
    - Barium Sulfate
    - Iron Sulfide
    - Iron Carbonate, Iron Sulfide, Iron Oxides
    - Sand

Again this list is not exhaustive.

Of equal importance to knowing the type of material, is knowing the potential volume of material. The classic dilemma is where there is an increase in the overall pressure drop across a pipeline during production. It is obviously some type of flow restriction, but knowing whether it is a short narrow restriction or a long slight restriction is of fundamental importance in determining an effective cleaning approach. In one case the volume of material could be very small in the other it could be much larger. This is important not just from a treatment perspective but also from a disposal perspective.

One other significant issue is how the material(s) relate/adhere to each other and with the pipeline wall

The available techniques and tools for dealing with these different types of materials are dealt with below but it is worth restating that the more we know of the problem the more effective the solution will be.

Reason for cleaning (level of cleanliness)

The required level of cleanliness is also a major factor in the selection of a cleaning technique. We will consider three basic reasons for cleaning: -

- Inspection Runs
- Efficiency Gains
- To Remove Hazardous/Corrosive Material

Even within these categories there are differing requirements.

For example if the need is to clean for an inspection tool run, then the level of cleanliness required is higher for Ultrasonic tools than it is for MFL tools.

Cleaning for improved efficiency is perhaps the easiest situation to deal with as any debris removed is advantageous and there is usually an economical cut off point on cleaning costs Vs efficiency gain.

Cleaning to remove corrosive or hazardous materials tends to be the most onerous level of cleaning, as some level of satisfaction must be obtained on the complete removal of the material in question.

Measure of Cleanliness
The measure of cleanliness itself remains a difficult and usually subjective measure.

International standards for pipeline cleanliness are not used in the industry and to the knowledge of BJ Process and Pipeline Services do not exist. There are a number of standards for hydraulic system cleanliness, surface roughness and surface preparation, but none that deal specifically with pipelines.

The normal method for cleanliness assessment, with mechanical pigging techniques, is to monitor the volume of debris removed and with decreasing volumes recovered, reach a determination on the completeness of the cleaning operation, based on the experience of the personnel involved. For pre-intelligent cleaning operations this is a critical decision as inspections vehicle sensor arrays are easily fouled with deposition material.

There are tools in the market place that can be used to measure the thickness of the deposition along the length of the pipeline. This tool operates in the same way as a caliper tool but has very soft springs, allowing the sensor arms to deflect thereby recording the deposition profile along the pipeline.

Cleaning Techniques and Tools

This paper deals only with cleaning pipelines, which are, or have been, in service.

For the purposes of this paper we will consider four basic techniques for cleaning pipelines and pipeline systems.

- Mechanical Cleaning
- Chemical Cleaning
- Cleaning with Gels
- Other Potential Techniques

High velocity flushing is not considered here as it is primarily applied to small diameter shorter pipelines and is normally applied at the precommissioning stage.

Mechanical Cleaning
Mechanical Cleaning could be described as using a solid object(s), to scrape and push pipeline detritus and debris from the pipeline. In most cases this is some form of pig, although spheres and other objects have been used. The pig can be displaced with line

product but equally another displacement medium such as water, air or nitrogen can be used
A prerequisite of mechanical cleaning is that the pipeline is piggable, however recent developments in pig and pipeline system design is such that systems previously deemed unpiggable can now be reclassified. These included: -

- Multi-diameter systems
- Gathering lines feeding directly into trunk lines
- Systems with wye connectors

One major disadvantage of mechanical cleaning is the transportation or removal of the debris from the pipeline. As the pig is displaced through the pipeline, material has a tendency to build up in front of the pig. This build up can get to the stage where there is not enough available displacement pressure to continue, or the required displacement pressure is higher than the MOAP or even the design pressure of the pipeline. For these reasons it is common practice during mechanical cleaning operations to limit the number of pigs in the pipeline at any one time.

Of key concern in mechanical pigging is the interface between the pipe wall and the cleaning attachment or accoutrement. In most cases it is the interaction of the cleaning brush with the pipewall. Brush design and pig design have evolved with more attention being paid to the effectiveness of the brush in debris removal. This is sometimes called enhanced pipeline cleaning.

In general terms the brush should be of a design that is rigid enough to remove the deposition but not damage the internal diameter of the pipeline. There appears to be consensus that direct mounting of the brush to the body of the pig and using the spring stiffness of wire bristles is the most effective design. Brush design where the entire brush is easily deflected or where the bristles are easily deformed should be avoided. Typical of this design is the Inline PLC Pit Master brush, which is used to scour out Microbiological Influence Corrosion (M.I.C) pits in the pipewall.

In addition to heavy duty brushes there are a number of other designs of enhanced cleaning tools. These are extremely useful tools and utilization of these has allowed cleaning of pipelines to a level, which would previously have been unobtainable. However care must be taken in the application of these tools both in terms of the blockage issues highlighted above and with damaging the internal wall of the pipeline.

Pipeline cleaning pig's range greatly in type and material of construction. The following list details some of these used. This list is not exhaustive and many combinations of these pig types can be used.

- Low density polyurethane foam c/w Brush
- Bi-directional scraper pig
- Standard bi-directional scraper pig c/w magnets
- Standard bi-directional scraper pig c/w brushes

- Cup pigs
- Solid cast polyurethane
- Jetting pigs
- Pin wheel pigs
- Bulldozer pigs
- Heavy duty bi-directional brush pigs
- Heavy duty bi-directional magnetic pigs

Chemical Cleaning

Chemical treatment for pipeline scales/deposits are numerous and often routinely applied.

For the purposes of this paper we will consider three categories of chemical treatments and review the effectiveness of each. It should be noted that in almost all cases chemicals are in slugs between batching pigs. Compatibility with pig materials and pipeline coating systems must be fully considered. The three categories are: -

- Solvents
- “Reactive” Chemistry
- Surfactants

Solvents

Typical solvents include diesel, terpenes, naphtha, and alcohols. Solvents are used to dissolve organic material, in particular light end hydrocarbons; usually deposits are a mixture of heavy and light end hydrocarbons. The solvents therefore break up the hydrocarbon depositions making subsequent mechanical pigging operations more effective.

There are several drawbacks with this approach. Solvents are less efficient at the temperatures typically found in pipeline systems. Contact time is also an issue, solvents require time to work and even in low flow situations the available contact time between the deposition and solvent slug may not be enough. Economic considerations may rule out extending the slug length and hence the contact time. Disposal can also be an issue.

Solvents do have a place and are worthy of consideration but need to be carefully engineered.

Reactive Chemistry

“Reactive Chemistry” is a very broad term for acids, complexors, chelants, and caustics etc. This chemistry works by reacting with the scale or deposit; typically this may be used on the inorganic scales or corrosion products. This is a high risk approach, very careful consideration needs to be given to the reaction between the chemistry, the material targeted for removal and products that are potentially in the line.

Liberated gas can be an issue and as per solvents this chemistry is less effective in the temperature range typically found in pipeline systems. In this case the concentration of the reactive chemistry could be increased to improve the efficiency, great care needs to be taken with this approach. Contact time is again an issue as is disposal.

This is a chemical reaction, which continues until the reactive material is spent, consideration needs to be given to the displacement operation stopping at any point and the interaction between the pipeline and the chemistry.

Typically corrosion inhibitors are mixed in with this reactive chemistry and these also can have a significant disposal issue.

This chemistry is better suited for plant situations where there is more control and the volumes are usually smaller. This chemistry should never be used unless there is 100% confidence in the integrity of the pipeline.

Surfactants
Surfactants or surface acting agents are essentially soaps that form a solution, in particular with light end hydrocarbons. As with all chemical treatments these do not work as efficiently at lower temperatures and contact time needs to be considered. This chemistry can be very effective in assisting with mechanical pigging operations. There is a disposal issue as with all chemistry, however there are surfactants that essentially work “dynamically” and where over time the displaced solution will separate. Surfactants are fairly commonly used in chemical cleaning applications and are usually easier to handle than the other options.

Cleaning with gels

Gels are highly viscous gelled liquids that have a number of applications in the life cycle of a pipeline. In terms of pipeline cleaning techniques the primary application is in the transportation of unwanted materials out of the pipeline. Gels typical do not clean the pipeline but are a very effective way to increase the efficiency of the cleaning process by removing large volumes of materials from the pipeline.

Most pipeline gels are water or hydrocarbon based.

Types of Gel Pig for Pipeline Cleaning

- Debris pick-up gel
- Paraffin solvent gel

Separator gels are commonly used in gel cleaning trains but are not dealt with here as there function is not related to cleaning or transportation of debris.

Debris Pick-up Gel
All types of gels can pick up and transport loose debris, but with variable efficiencies and loading levels. The debris pick-up gel is usually a high-viscosity, shear-thinning Bingham plastic. It has a high viscosity at low shear rates and high yield strength, which ensures that the debris remains suspended even if the gel is static for long periods. Both the

plastic viscosity and yield point increase as the debris-loading increases. The gel cleaning approach uses mechanical pigs to break up debris in the pipeline into small particulate. It then uses the viscosity of the gel to mechanically carry the particulate in suspension. The gel is normally designed to carry 1 lb/gallon of debris, but experience has shown that under adverse conditions it can carry as much as 10 lbs/gallon. As such the system is very forgiving. In addition, the suspension capability is independent of velocity, thus if the pig train gets stuck or slows down the debris will remain in suspension until the train resumes its normal progress

Paraffin Solvent Gel Pig

Gelled solvent penetrates and breaks the deposition from the pipeline wall. In all other aspects they work in a similar way to debris pick up gels, although the carrying capacity is reduced.

For disposal, if required, a chemical breaker can be injected into the gel as it is leaving the pipeline, causing the viscoelastic structure to be destroyed. In this broken state, the gel is easily discharged, collected and pumped away for further handling or the base fluid reinjected into the system, as would be the case with hydrocarbon base gel. Water based gels are fully biodegradable with no adverse environmental impact. In a similar fashion a breaker wash can be applied to the pipeline to remove any residual gel.

Other Potential Techniques

The intent here is only to highlight potential solutions to unique conditions, which would require unusual or alternative solutions. Whilst some of these concepts are field proven others are offered forward as potential solutions. This is particularly true for the situation where a pipeline system has a dead leg and it is not possible to engineer more conventional solutions. Dead legs are lengths of pipework that are blanked off and through which no flow is possible. It is not possible to pig true dead legs.

Other potential techniques include: -

- Coil Tubing
- Hydraulic Work Over (Snubbing)
- Clearshot™
- Retro Jetting
- Exothermic Reactions
- Automatic Multi-Pig Launching System

Coil Tubing

Coil tubing is commonly used in the oil field services business and as the name implies is steel tubing coiled onto large reels. Coil Tubing diameters typically are in the 1 to 2 ½ inch range. Coil tubing can and has been used in pipeline cleaning operations. The coil is introduced or injected into the pipeline through an injector head. The coil is fed into the line through the rotation of the reel. Simultaneously fluid is pumped through the tubing. The deposition is removed through a jetting action, if a jetting head is attached to the end of the coil, or simply through a chemical wash if solvents or surfactants are used. One major advantage of this approach is that coil can be displaced down a dead leg.

There are several disadvantages with this technique. Coil tubing units are heavy and very difficult to transport to remote pipeline locations. This is also a very expensive approach. Coil also suffers from a tendency to "helix lock". This is where the coil takes a helix position inside the pipe and there is not enough pull force to retract the coil. For this reason coil is normally limited to between 6,000 to 8,000 feet. The longest intervention on record was through the application of the Superior Energy Services CoilTAC™ system where 14,800 feet of 4 inch flow line was cleaned. Tractor tools can be used with coil to increase the insertion length but these have been developed for downhole application and the effectiveness of this in a pipeline application is unknown.

Hydraulic Work Over (Snubbing)
This technique utilizes a hydraulic work over unit (snubbing unit) to insert drill pipe rather than coil, this eliminates the helix lock issue but this technique is only applicable to straight lengths of pipeline and is again very expensive and difficult to transport to remote locations. The actual cleaning mechanism is the same as with coil. With both coil and snubbing the deposited material is removed from the pipewall and into the general fluid stream it is not positively removed from the system.

Clear Shot ™
BJ Clear shot is one of a number of techniques that utilizes hard spherical material (steel in BJ's case) entrained in a high velocity gaseous nitrogen stream to displace material adhering to the pipewall. Typically used on fired heaters in the Petrochemical Industry this technique has been utilized on pipelines. For this technique the pipeline has to be drained of liquids, and this application is only effective on hard deposits and the circumstances where this would be the preferred option are few and far between. Bend erosion can be an issue as can shot left in the pipeline.

Retro Jetting
This is sometimes referred to as line moling. This technique is used to clean existing pipe spools and works through the introduction of a retro jetting head into the pipeline the head is displaced by very high pressure liquid (usually water). The head has several jetting nozzles that are positioned to allow the head to remove all material from the pipewall and to displace the head down the pipeline in a helical path. The jetting head is much smaller than the pipeline ID and is not displaced down the center of the pipe but at the pipe wall. This technique is only used when the line is drained and is often used with open ended pipe.

Exothermic Reactions
An exothermic reaction is one in which a chemical reaction releases heat into its surroundings. There are several ways to do this; oxidation-reduction and acid base are two that are used. This technique is used where there is a localized build up of hydrocarbon residue and the released heat softens or melts the deposition. This can also be used in conjunction with a solvent or a surfactant to increase the efficiency of the

process. The oxidation-reduction technique releases large volumes of gas (Nitrogen), this needs to be carefully considered if this technique is to be investigated. The effect of internal coatings would be another consideration.

Exothermic techniques are not considered to have wide application and would tend to be a solution of last resort.

Automatic Multi-Pig Launching System

Although not in itself a cleaning technique or tool this system, which is under development by Pipeline Engineering has widespread application in remote locations. The system contains a number of pigs within a bespoke cassette designed in compliance with existing pressure vessel/pig launch equipment. The pigs and cassette arrangement are designed to allow automatic displacement of each pig based on a preset pressure in the launcher. The next pig slots into the launcher and is in turn launched when the preset pressure is reached. The system is due undergo trials in November.

Online Filtration/Separation Pipeline Cleaning

During gas pipeline cleaning operations, temporary online filtration can be used to protect the permanent system filtration. With liquid systems the utilization of temporary inline separation can be used to protect the permanent systems from contamination, from both the cleaning medium and the solids removed. This allows the operator to continue production throughout the cleaning and inspection process

Conclusions/Recommendations

Whenever possible design pipeline systems to allow regular maintenance pigging.

In the situation where a pipeline or pipeline system has not been subjected to a regular maintenance pigging regime but is piggable then collect as much data as is possible about the pipeline system, the type and volume of the material to be removed and develop a strategy that minimizes the risk to people, the environment and the pipeline. This process is fundamentally a risk assessment and should be treated on that basis.

In the situation where the pipeline is not piggable, where reasonably possible, make it piggable. Where not reasonably possible, ensure that the proposed solution is thoroughly tested and trialed; do not experiment on your pipeline.

There are a number of cleaning techniques available in the marketplace. The industry has a record of going to a solution too quickly and trying to fit the solution to the problem. Better to take the time to fully evaluate and understand the problem then fit the problem to the solution.

In remote locations it is typical to apply the available solution and not necessarily the best solution. Niche expertise is not always available for consultation or advice. As the worlds leading provider of Pipeline Cleaning Services BJ Process and Pipeline Services is pleased to announce it is in the process of transferring pipeline personnel and equipment to Alaska. We will operate out of a sales/engineering office in Anchorage and an operational base in Kenai and hope to be of service to you in the future.

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1. UZU O (BJ PPS), NAPIER R (BJ PPS), NGWUOBI K(SPDC) Gel pig technology applications in pipeline services 24th SPE Nigeria Annual Technical Conference and Exhibition held in Abuja, Nigeria, 7-9 August, 2000.
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4. KEYS. M. BJ PPS

APPENDIX D

MAINTENANCE PIGGING CONFERENCE PRESENTATION 4

LATEST TECHNOLOGY IN PIG DESIGNS

BECKY LIBBY OF ENDURO PLS

ABSTRACT OF PRESENTATION 4

Latest Technology In Pig Designs

Speaker Name: Becky Libby, Sales Manager

Company Name: Enduro PLS

Website URL: http://www.enduropls.com/

Type of Business: For 20 years Enduro has been offering a wide range of pipeline cleaning products including steel bodied cup and disc pigs, urecast, bi-directional, and standard poly foam pigs.

This presentation will provide a discussion of the latest developments in the following areas:

- Technology of pig designs
- Pig designs to increase effectiveness of pigging runs
- Pig designs to enable pigging of pipelines considered unpiggable (e.g. due to multi-diameter piping, short or mitred bends, undersized valves, etc.).

TRANSCRIPT OF PRESENTATION 4

We have one more presentation this morning and this is by Becky Libby. She is the sales manager for Enduro Pipeline Services, and has more than 17 years of experience. Becky has designed dual diameter maintenance pigs for application on the Mardi Gras system and for other oil and gas industry's pipeline operators.

Becky is the only thing standing between us and lunch.

Becky Libby**:** I have been asked to discuss on pig designs. Technology of pig designs, pig designs to increase effectiveness of pigging lines. Pig designs to enable pigging of pipelines considered unpiggable. Some of the causes from mitred bends, undersized valves, and areas. And I think as all of the pig manufacturers have discussed, there's not been a large increase in technology for utility pigs and cleaning pigs recently. And that's for single diameter pipelines.

The pigs have been designed in different unique configurations for specific applications but the performance for these types of pigs have been maintained the same configuration for a number of years. I think we've all tried to enhance brushes the urethane, I know that we've all learned different ways, different techniques to assemble the pigs with different durometers of urethane to provide more effective cleaning. And as stated there are different brush configurations, wire diameters and other things like that to increase cleaning abilities of the pigs.

Some of the newest technology in pig design is available for dual diameter and multiple diameter pipelines. A large focus has been placed on pigging designs in an effort to try and provide the same cleaning ability for these pipelines that is available for single diameter lines.

Pig designs can increase effectiveness of pigging runs. There are several different ways to modify a pig design to increase the cleaning effectiveness. And some of these may be, if you're running a two-cup pig and added scraping disks to that pig, will increase the effectiveness. Adding brushes, adding magnets, and adding bypass through the cups and or disks on the pig. Bypass is designed and used a lot in pigging pipelines which have already got a lot of debris built up. All that does is create a turbulence effect out in the front of the pig and keeps the debris--keeping it suspended out in front of the pig and away from packing it around the pig.

There's a lot of companies here that use that. It's a very effective way to keep the lines from plugging up. Another way is, as discussed before, combining different pig configuration and trying to--it is also a way to increase effectiveness of the cleaning pigs. Cleaning pig trains should only be run once the pipeline has been proven piggable and any initial problematic debris build-up has been removed. If there is already an amount of debris probable, a cleaning program should be outlined prior to running a pig train.

The cleaning program would begin with less effective pigs, progressing to more aggressive pigs, in stages up to the cleaning pig train. You might start out with pump pigs, a 2-foot pig as shown in the upper left-hand side. Cleaning for that leads to the pigs followed by the second section is disk and brushes, the third section on the upper right-hand side is a disk pig with magnets on it. The pig trains run have multiple cleaning components to run in a single path. Cups, disk brushes and more magnets can all be ran at one time. The additional weight of these tools will enhance the cleaning effectiveness of the pig.

This type of cleaning pig can be used as a dummy tool for some manufacturers claim prior to running the inspection tool. I know that there are a lot of the companies that will allow to use once the pig train has gone through the line, they will accept that as acceptable prior to running that inspection tool.

Pig designs to enable the pigging of pipelines considered unpiggable use multiple diameter piping for the mitred bends and undersized valves. Custom pig designs can be manufactured for pigging multiple diameter and dual diameter pipelines.

The pig, the upper pig on the right-hand side--that's a pig that was designed to pig an eight by twelve pipeline that internal diameters were five inches by ten inches. That pig is also designed to accommodate brushes. The bend radius in this line was three feet also. So, it's got quite a restriction to go through and brushes aren't available for that pig also.

Designs are available for pigging through the lines. The pigging of the lines can be accomplished by adding the length of the pig line sufficient to ensure that the front disk got contact, the downstream contact prior to your disk cups were in contact with the upstream pipeline entering the line. The increased length of the pig will require that the bends in the pipeline will be such to ensure passage of the pig through the bends.

The bottom picture there is a pig design that was designed to go through the Y's. The length--the body diameter on that pig was made smaller to accommodate, so that the pig can traverse through the bends. The upper pig it's also traversing, going through the lines and the pipeline in that certain pipeline.

So there are designs out there that have been put forward for pigging the lines. The bend restriction that pigs have to go through is pretty critical and really needs to be taken into consideration when the pig design is manufactured.

That upper pig--there's a joint assembly that's a small urethane u-joint assembly in there that had to be manufactured in that pig to allow it to traverse the bends but stiff enough to pass through the Y.

So the design of the pig is pretty crucial that all information is provided to us when we start these projects.

Brush and magnet pig designs for cleaning dual diameter and multiple diameter pipelines: these cleaning pigs for dual diameter and multiple diameter lines are available and can be manufactured to pig 1-1/2--for pipelines with a minimum bend radius of 1-1/2 feet. Those do require pig train and prior to putting one of these in the lines, we would want to start out with like a trigger pig which may be the front section on this bottom picture or a foam pig even to improve passage of the line prior to installing something like this. Both of these pigs are designed with brushes and magnets.

The bottom picture there is actually a ten by twelve and that does have brushes and magnets on the rear section. And both pigs are designed to traverse 1-1/2 feet bends.

There's a lot that you can do with dual diameter on pig designs. I think that a lot of our focus has been placed on the designs for these lines.

For pigging lines with undersized valves, depending on the difference of the main line internal diameter and the internal diameter of the valve, pigging these lines can be achieved with two different options: pigging lines with internal diameters greater than two inches should be done using pigs with dual diameter sequence components.

In the picture that's shown here, it has a combination of slotted dual diameter cups and sealing units that would be sized to the diameter of the valve. That could be used for a trigger pig also in your line.

Pigging lines with an internal diameter change not exceeding two inches could be done using a pig with conical shaped cups, and again that conical shaped or the pig design--something with a dual diameter cup on it could be used for that application also.

For pigging mitred bends, it is recommended that all mitred bends be removed prior to pigging. However, utility pigs and cleaning pigs can be designed for mitred bends if the radius of the bends is large enough to allow for the pig to pass through them. Most geometry inspection tools and ILI tools are not designed for mitred bends. Prior to running an ILI tool, once you verify that the ILI supplier tools can pass through mitred bends, actually the design and fabrication of the mitred bend will be definitely a factor.

The picture on the left-hand side shows just a two-cup pig typically going through--that's a 1-1/2 feet bend. The one on the right shows you how in mitred bends you are going to break the seal. Again, I don't know if any manufacturer would recommend or will allow that the inspection tools can pass through the bends.

That's pretty much all I have. There has been a lot of advance for pigging multiple and dual lines. It's possible to get through those and the valves--there's just a lot of design technique out there to be used for pigging through these lines.

TRANSCRIPTS OF QUESTIONS FROM THE PANEL

M: Questions from the panel?

Mark Peterson, BP: First, one of the things that came up in a recent pig campaign that we had was the durometer. Would you explain durometer and what the durometer ranges that Enduro lists?

Becky Libby: We manufacture off of our machines 75, 85 and 95 short A urethane. We can hand-batch other durometers. The difference in the durometers--the 75 is a softer durometer. The 85 is a little bit harder and the 95 is quite a bit harder. The 75 for cleaning applications will not provide--is not as aggressive as an 85 short A urethane. That's a good durometer to use for batching applications or to start out a cleaning pig program. We would certainly consider using 75 and then increasing the durometer to 85 as part of the pigging program.

M: Does that answer your question? Okay. Other questions from the panel? Please.

Dave Hart, Pioneer Natural Resources: You gave a good overview on recent pig design improvements. In your opinion, where do you see is the next area of opportunity for pig design and improvement?

Becky Libby: I think we're all trying to focus on improving even single diameter pigs due to--we need to get the lines cleaner for the internal inspections, and to remove the corrosion. And as we've all discussed, in the past everybody's ran pretty much generally flat wire brushes and as Gary demonstrated, the flat wire doesn't remove the--it removes the hard scale but doesn't actually clean the pits. And I think we, as manufacturers, are trying to improve the pigs overall for the end users for the removal of corrosion and try to advance for such.

M: Does that answer your question? Other questions from the panel?

Chuck Knecht, ConocoPhillips: Becky, dual diameter pipelines--what is your biggest step change you guys had successfully used?

Becky Libby: Large diameter or small diameter?

Chuck Knecht: Large diameter.

Becky Libby: All kinds of range. Twelve by twenty is one of the largest that I've done--that we've done. 24 by 30; 36 by 48. We've got some substantial change.

M: Okay. Other questions from the panel?

Bill Hedges, BP: Becky, what would you do with those large changes? What would you estimate the efficiency of cleaning is compared to if you could put a pig into the exact correct diameter?

Becky Libby: The design--speaking from a manufacturer's point, the design that we have as valid for dual diameter has proven to minimize bypass. I know that the aggressiveness of the dual diameter products is not as great. You can't provide it. We have a 34-inch, but you're not going to--I can't put a number on it. You're not going to get nearly the benefit of the pig as you would a single diameter.

M: Does that answer your question? Other questions from the panel? Becky, thank you.

TRANSCRIPT QUESTIONS FROM THE AUDIENCE

M: “How does the increase of urethane durometer affect its wear properties?”

Becky Libby: I’m not sure how it affects it the 75 softer durometer wears better, it increases the life of the urethane. There’s not as much friction against the pipe wall and it does increase the life. It provides a better seal but is not as aggressive as the harder durometer.

M: Anybody have anything to add? Please.

Gary Smith: I usually describe it to people that ask that kind of question--if you had a belt grinder and you put your knuckles into it as far as you could, they are very similar to urethane. The harder the urethane is, it gets to a point between the mid-seventies to around 80, 82--it has its best wear resistance. When you get above that it’s so hard that it just wears down too quick.

On the soft side you actually have--it’s more flexible so you don’t have as much pressure against the pipe wall. As Becky said it’s a better sealing surface, but normally when you get into the lower range of urethanes the wear resistant properties are not near as great. So most of what you’re going to see outside of the exhibits in any of the other manufacturing, are going to be between 70 to 82 short A unless they are getting into a real in-depth cleaning operation where they want to go to something that is harder, then they go to something above 82.

M: Any other comments? Okay. Next question. “For multi-diameter lines”--this is the question--“do the larger cups or disks fold down or collapse when entering the smaller diameter portion of the pipeline?”

Becky Libby: The cups and disks are designed with V-slots in them generally, and they do fold back which causes the cup or disk to pull them similar to a cup in the smaller diameters, so yes they do fold back in the smaller diameter.

M: Any other comments from our panel? Okay. There should be a drum roll, I think here. This is the last question. “Do the pig manufacturers have quality control standards for determining when the disks, cups and brushes are worn out?”

Becky Libby: That depends on pipe wall thickness, product in the line, the length of the line, there’s really--a lot of--as per line, I don’t think there’s really a standard. Once you get a routine set on your pigging and determine how much wear you’re going to have per run, that’s pretty much what you base it on. We can tell you that once you get to about 1/8 inch over the internal diameter, then you might want to look at changing it. But there, again, that depends on the length of the line and how much wear you are actually receiving per line.

M: They have a “such as” here. Let me just make sure that we’ve covered that because they have their own ideas as to what this might be. “The internal diameter of pipe that’s remaining outside the diameter of the cups, disks, brushes.” Is that possible? “Do the pig manufacturers have quality control standards for determining when the disks, cups or brushes are worn out?” And their suggestion here is, “Such as internal diameter of pipe to remaining outside diameter of the cups, disks and brushes.”

Becky Libby: Well, there again that’s going to depend on the pipe wall thickness. If you have a six-inch line with a quarter-inch wall versus a six-inch line with half-inch wall, you’re obviously going to get more wear out of your cup in the half-inch pipeline than you would in the pipeline with quarter-inch wall.

M: Any other comments from anybody on the panel? Please

Steve Sauer: Yeah. I will say that in terms of wear and tear of some of these pigs that travel some tremendous distances, back almost thirteen years ago we pigged a 578 single run line. That was dry. On the pig that we dewatered 75 miles of 24 inch and there was almost no wear on the pig. So, you know, it sounds like somebody's concerned about over-wear. These things can be designed so they wear very, very little.

M: Any other comments from the panel? Please.

Chuck Knecht: Typically on our sales oil line what we did was measure the OD of the actual disk, filling disk, and when it falls below 3 to 5 percent of ID we change them out.

M: Any other comments? Please.

Derek Clark: Yeah. I'd just like to say if we're sizing pigs for a job, normally the root pigging--it's not production pigging, its pre-commisioning pigging when the lines are new that we'll make sure that the disks are sized for the diameter. We are not going to buy a generic--we wouldn't buy a generic 12-incher or 16-inch. We would make sure that the OD of the disk was matched to the actual line diameter and I think if I remember I was looking for usually about 5 percent overage. So the disks are about 5 percent in excess of the internal diameter of the pipeline. And we we certainly wouldn't rerun the same unit in the line. We would change out disks if we would rerun that pig.

M: Any other comments? Okay. Thank you very much.

APPENDIX E

MAINTENANCE PIGGING CONFERENCE EXHIBITOR INFORMATION

Integrated Pipeline Services

PIPELINE PRODUCTS AND SERVICES

Providing a Broad Range of Services for Pipeline Compliance and Integrity Assessment

ENDURO

Pipeline Services

Represented By

Pipeline Supplies and Equipment

Maintenance Cleaning and Batching Pipe Pigs

For 20 years Enduro has been offering a wide range of pipeline cleaning and inspection products to fit all of your applications. Products include steel bodied cup and disc pigs, urecast, bi-directional, and standard poly foam pigs for all your cleaning, batching and displacement applications. The rugged design and strict manufacturing guidelines of the Enduro products allow them to stand up to the toughest cleaning jobs. Every aspect of manufacturing and engineering is done at Enduro which allows for innovative solutions to the most difficult requirements you may have. SL Pacific, Inc. has had the distinct pleasure of representing Enduro in the Northwest for 8 years and offers local service, and inventory of pigs and pig parts. SL Pacific is a company that prides itself on service above all else and Enduro's service reputation is well known throughout the industry.
Other products available are: Pig Poppers, Pig locating and tracking equipment, and (through SL Pacific, Inc.) Pig Launchers and Receivers.

Inline Services focuses on providing innovative pigging equipment for the customer's applications

Inline Services is one of the fastest growing manufacturers of pigging equipment to the oil, gas and product pipeline industry. Inline's Pipeline Cleaners Inc division designs and manufactures mandrel pigs and brushes. PLC is one of the oldest pig manufacturers in the world. Its Pilley Brush division began operating in 1889 and formed its pig manufacturing division in 1936. PLC makes heavy-duty ring and block brushes for aggressive cleaning of deposits as well as specialty brushes for cleaning pits caused by corrosion.

Inline's Universal^{TM} Mandrel Pig Series is a versatile approach to enhanced cleaning and sealing, utilizing combinations of cups, discs and brushes. Our Foam Disc Pig(tm) offers maximum performance with its multiple discs design. Concentrating on innovative and high quality products, Inline provides to its clients products manufactured by industry leaders such as Knapp Polly Pig, Nautronix sub sea pig tracking systems, Apache PigPro signalers and ACECO side loading pig valves. Inline also offers pipeline dust bags, closures, and other pigging equipment.

Inline is widely known for its approach to solving pipeline pigging problems from commissioning to routine and complex maintenance operations with "built for purpose" equipment. Combining this concept with excellent design capabilities and using the best materials available, Inline delivers products to solve the most difficult pipeline pigging applications." *P&GJ*

MAINTENANCE PIGGING PRODUCTS AND SERVICES

Pipelines, no matter what they transport, should have a clean inner surface to ensure efficient pipeline operations and high-quality inline inspection results . . . resulting in lower operating costs.

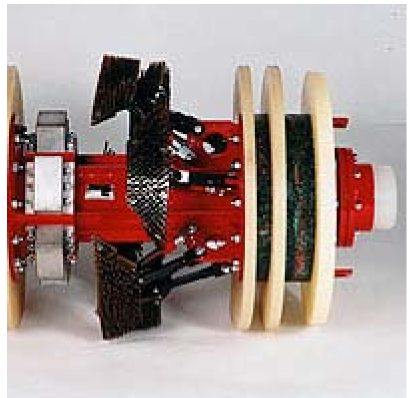
ROSEN cleaning tools are the most efficient tools in the industry. ROSEN cleaning tools are designed to achieve optimum cleaning results in all possible circumstances and pipeline conditions including 1.5D bends and heavy paraffin, wax, scale or dust build-up.

Cleaning tools consist of a standard tool body to which any combination of accessories can be mounted, including high-wear-resistant polyurethane cups and discs.

Gauge Plate	determine whether large obstructions exist which would block passage of an inline inspection tool
Spider Nose	create turbulence to avoid accumulation of debris and wax in front of the tool
Brushes	scrape solid debris from the pipe wall
Magnets	collect loose metal components and carry them out of the pipeline
Transmitter	measure exact tool passage time or pinpoint a lost tool

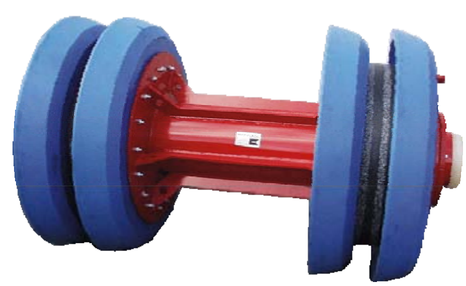
A **Pressure Bypass Nose** can be mounted in front of the cleaning tool. If the tool becomes lodged and the pressure inside the pipeline increases, this valve will open so that flow is maintained.

ROSEN's **Pipeline Data Logger** assesses the temperature, pressure and pressure differential profile along the entire length of a pipeline in runs up to 500 km.



Use ROSEN's Cleaning Tools for:

Cleaning after construction	to remove construction debris from the pipeline and for dent identification
Cleaning before inspection	to achieve optimum inspection results
Maintenance cleaning	to mitigate corrosion by removing aggressive production debris
Operational cleaning	to maintain flow rates by removing obstructive production debris



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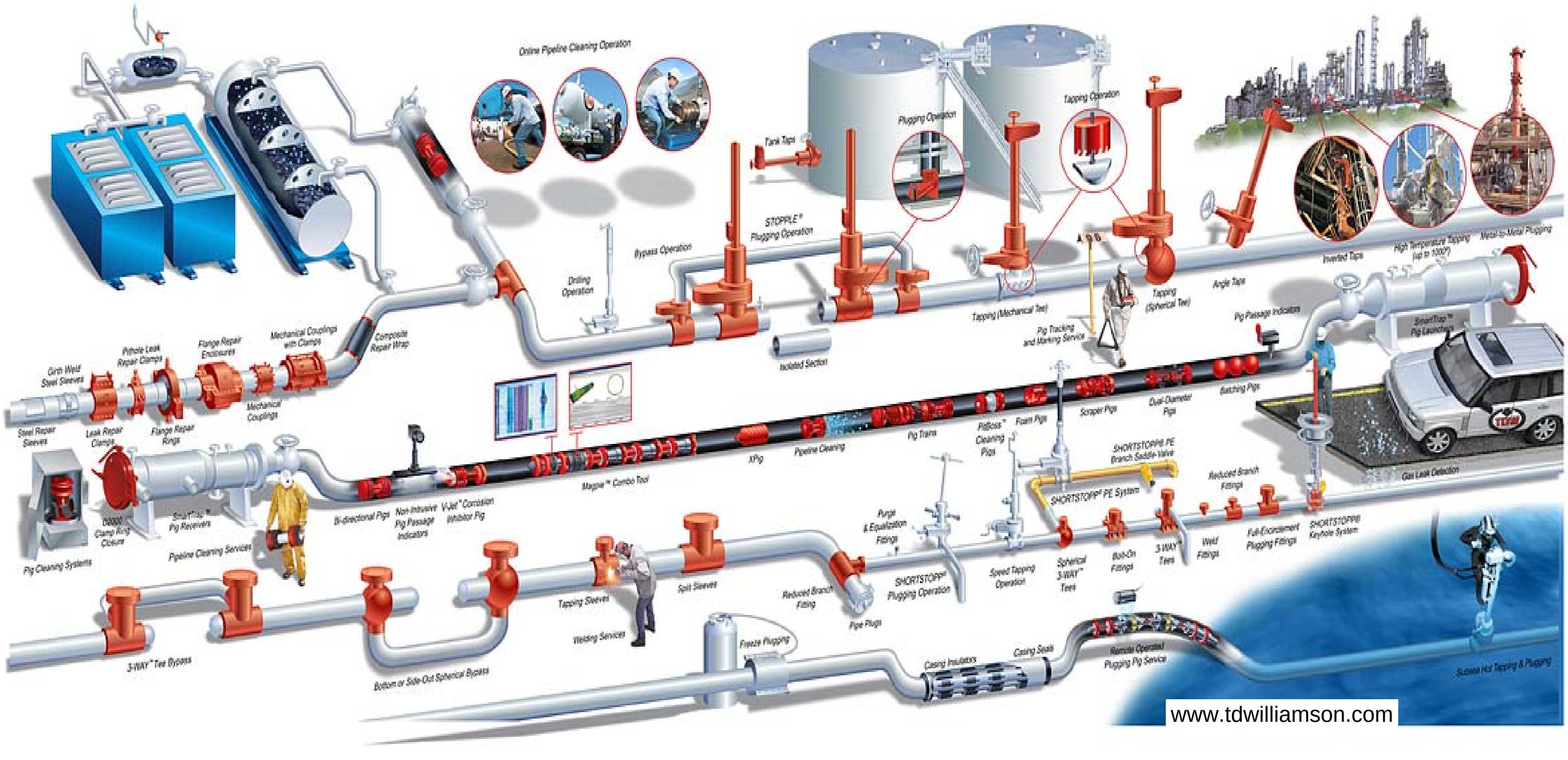
Pipeline Performance

Corporate Capabilities



APPENDIX F

INTELLIGENT PIGGING CONFERENCE PRESENTATION 1

INLINE INSPECTION USING MAGNETIC FLUX LEAKAGE TECHNOLOGY

FRANK SANDER OF BJ PIPELINE INSPECTION SERVICES

ABSTRACT OF PRESENTATION 1

Inline Inspection Using Magnetic Flux Leakage Technology

Speaker Name: Frank Sander, Non-Destructive Testing (NDT) Research Analyst

Company Name: BJ Pipeline Inspection Services

Website URL: **www.bjservices.com**

Type of Business: BJ Pipeline Inspection Services provides smart pigging services to the Process and Pipeline Industries to verify pipeline integrity.

Frank Sander will provide a brief description and function of the different types of MFL tools. Topics of discussion will include:

- Advantages and disadvantages of the MFL technology;
- Planning and preparation for an in line inspection with MFL (pig launchers/receivers, 3-phase lines, etc.);
- What makes a successful MFL pig run;
- What types of pipeline defects can MFL detect, identify, and and/or size accurately;
- MFL reporting (time required for analysis, integrity analysis, dig sheets, etc.);
- Current advances and the future of MFL technology.

TRANSCRIPT OF PRESENTATION 1

Now, I would like to introduce our first presenter. This is presentation number one and the presenter will be Frank Sander.

Frank is from BJ Pipeline Inspection Services and will talk about magnetic flux leakage, or MFL, and transverse MFL. Frank has a Bachelor of Science degree in applied physics from the University of Calgary. Since 2001 Frank has been with BJ Pipeline Inspection Services working in research and development, primarily with MFL. His research projects include the testing and verification of new inspection tools and technology as well as the interpretation of MFL signals from pipeline defects.

So, with no further delay, Frank, if you'd take the podium? I appreciate it. And Frank has a 30 minute presentation followed by 10 minutes of questions from our panel.

Frank Sander: Good morning, everybody. Thank you for that introduction, Tom. I hope I can get within that timeframe.

I'd like to thank everyone for coming here today. I appreciate this opportunity to come here and speak to you about MFL technology with respect to the in-line intelligent inspection. I hope that you will leave here today with a better understanding of the general MFL technology, as well as an appreciation for how you rate a successful pig run and how you can compare the different tools in the marketplace.

So, I'd like to start things off by discussing what I am going to be spending the next 30 minutes talking to you about. First will be a brief description of MFL technology. I will discuss the two different types of tools, the standard MFL and the transverse field MFL. I will compare the differences and the similarities, and as well the different sensor types you have on those tools. And how the orientation of the sensors, the sensor types themselves and the resolution of them can detect different types of defects and features that you can find with the pipeline.

Next I'd like to ask the question, well, what determines a successful pig run? What are the important specifications of your pig that will determine whether you have a successful run or not? These are mechanical compliance issues such as bore, minimum bore, minimum bend radius, as well as operational issues like how fast your line is moving, especially with gas pipelines. As well as the type of product that you're moving. This is in respect to three phase lines, gas or oil.

Next I'd like to talk about the different types of features that you can detect, identify and/or size with MFL technology. MFL was originally developed in the late 1960's, early 1970's, as primarily a corrosion detection tool, which is the primary purpose still today. But there are other types of features that it can also detect, such as deformations, like dents, wrinkles and such, which I'll get into a little later on.

And then I'll actually show you what we actually supply a pipeline company in terms of report. What kind of information that we get and I'll supply a data sheet of a specific anomaly that was found from a fictitious pipeline obviously.

And at the end, I'd like to end up with some of the current events that we're doing with existing technology, things that we're doing with MFL that may have not been done in the past.

So, here is your pig. This is a typical MFL tool, and its basic components, so you can here see you have your drive cups--this is what propels the pig through the pipeline, the product pushes it through. This magnetizer volume here is the brains of the operation. This is what conducts the magnetism into the pipe wall, the sensors in the middle that can detect actual flux leakage, which I'll talk about in the next slide.

Here are where all the electronics, all the data is stored. The wheels here are for support to keep it centralized in the pipeline. You've got odometers that measure the physical distance that the pig has moved, and in this can you also have an inertia navigation system, which is a separate system of a pig. It has nothing to do with these sensors, but what it does is it maps the pig's trajectory through the pipeline. So that when you go out and dig you can find the spot.

So, let's take a look at some of the other pigs that are out there. Some of the vendors that you have in the exhibition over there. So you can see very similar the pig body here, you've got the cups, brushes here, the sensor ring, as well as secondary sensor ring, some wheels, as well as here the Tuboscope with the brushes, the sensors and really there's another one here. Yes, Rosen as well. So the brushes, the sensor, the magnet, the cups.

So, what I'd like to focus your attention on is here. These two brushes here with the sensors in between. You take a profile shot of that, here we can see the brushes, pipe wall, your magnets and your return bat. So what happens is you create a circuit, sort of like an electric circuit, where the magnets will create flux density within the pipe wall and it flows in a circular method.

So the goal is to saturate this pipe steel. Saturation, you can kind of think of it as a sponge, where a sponge can't accept anymore water--that's when the pipe can't accept anymore magnet flux and thus it leaks out. So when there is a metal loss corrosion feature, the magnetic flux density has nowhere to go but leak out. So if you run a sensor along the internal pipe surface of the wall, you can detect and pick up this flux leakage, and from that you can infer the size and depth of that corrosion feature. This is an important difference to get your head around. It's not a direct measurement of the wall thickness, but rather an inference. And a little later on I'll get into why that's so important.

So that's your standard MFL where you magnetize the pipe along the length of the pipe wall. So here is another similar diagram. So the other kind of MFL tool is a transverse tool. So that's what happens when you rotate those brushes 90 degrees and now you're magnetizing the pipe wall--it's going circumferentially around the pipe. As you can see there, the flux lines. And then when the flux leakage leaks out, you'll again have sensors that run against the inside of the pipe wall and detect that.

So what's the difference between the two? Oh, sorry. First, here's some pictures of the tool. So as you can see, very similar in the type of system--you have your drive cups, your brushes, but if you notice now that the brushes are orientated circumferentially with your sensors in the middle. So you can see on the smaller tools down here, you can see that there is actually two bodies that have magnets, and this is because you need to have the sensors all the way around the pipe so you can get your entire surface of your pipe measured.

So to do that with transverse MFL, especially with the smaller sizes, you need two tool bodies as you can see here with the GE pig, as well. Thanks, John, for the photographs.

And here is just another example of a transverse tool from Intertech, near Toronto there. Basically, it's the same. You can see these--the helical design. So you can see instead of having the magnets orientated around like that it's a helical design. That's just another way of mechanical design.

So what are the biggest differences between MFL? The two different MFL tools? Obviously, the main difference is the way you measure type of pipe. Either axially along the pipe direction, parallel to its length, or circumferentially. Now, when you magnetize, actually what happens is it is more sensitive to increasing width of the feature. That means if the corrosion, the width of it is in a circumferentially direction, that's what it's most sensitive to. So in order to detect and size features you need a specific width--you need a decent amount of width before you can start seeing signals. Whereas with the transverse MFL, the opposite is true. You need a specific length so it can detect much more thinner corrosion features.

So, as I was mentioning, it had a difficulty axially unbalanced, difficulty detecting narrow axial corrosion with a small width. Whereas with transverse MFL they can detect that thinner axial corrosion as well as large cracks.

Now, in terms of cracking, MFL technology itself, its limitation is that the crack has to have a significant opening before you can detect it. So a lot of the stress corrosion cracking out there doesn't have a huge opening, and so MFL hasn't really proved to be a great tool for stress corrosion factors.

Now both tools have velocity restrictions. This is due to the process of magnetizing the pipe. As you travel fast, you get eddy currents forming and that decreases that saturation level I was talking about. And then if you don't have the proper saturation, your flux levels decrease and you're not able to infer the proper information from your signals. Wall thickness is also an issue with regards to saturation. The more steel you have, the harder it is to saturate it with a magnetic flux. So, the difference between the tools in that respect is that with the standard MFL it's a lot easier to saturate the pipe wall. It's much more difficult to saturate the wall in a circumferential direction. So with the standard MFL tools you can get up to about 1 inch wall thickness and be able to saturate that properly. Whereas with transverse, it's typically up to about .6 inches maximum. These are typically with large inch diameter tools.

Another difference is in terms of the sizing accuracy. Because of the difficulty in saturating the pipe, what happens is the sensors that you have running around the pipe wall, they all need to see the same saturation of pipe. Different sensors see different amounts of flux leakage. That decreases your sizing accuracy. So with transverse MFL it's a little bit more non-linear. So you don't have all the sensors seeing the same field. So the sizing specifications are slightly lower. Typically with the standard MFL you'll see plus or minus 10 percent on depth. On the transverse MFL you would have a plus or minus 15 or 20. And that all depends on the size of the pig and a lot of times with different types of sensors you have, etc.

And, lastly, the smaller you have the tools with the longer the MFL tool is. Because you have less space to put steel in to magnetize the pipe. So typically you'll see that the smaller tools have many tool bodies.

So, you may have heard the terms high resolution and low resolution MFL tools. So, how do we determine--we can now specify the key questions in terms of how we determine the quality of the MFL tool. The first question you ask is what type of defects can we detect? Metal loss, deformations, what is the smallest defect that you can detect, and how accurately can these defects be quantified?

So, the magnetization level, as I previously mentioned, are by far the most important aspect in terms of determining if you can detect inside of them or that feature. As well, the flux density here needs to be at least 1.7 tesla, which is an extremely strong--these magnets that we use are the strongest permanent magnets available.

So, your sensor density and your sound frequency. This is the number of sensors that you have around the tool and how many times you collect data along the pipe widths. Typically, you've got about 12 millimeters, or .47 inches, that the sensors are around the tool circumferentially. That's for high resolution. And in terms of the distance between the time that you collect the data, it's usually less than 5 millimeters or .2 inches. So there is a lot of data that you collect.

Last but not least is your sensor technology and your orientation. The first MFL tools had induction coils. Some of the newer tools have hollow element sensors. The difference is that the induction coil--you have to integrate the signal, it's more processing. Whereas, the hollow elements have a DC response. So if you'll see how a lot of the more modern MFL tools have hollow element sensors.

Now, there's also the question of the orientation of these sensors. So to illustrate that--you have your pipe wall here. So when the tool runs you're going to have magnetic flux leakage coming out both in the external and in the internal circuits. So that flux leakage is going to come out in the axial direction, the radial direction and the circumferential direction. So you can have sensors that can detect in any one of those directions.

First, typical MFL tools only had sensors that picked up the leakage in that direction, and the more modern tools have sensors that can detect also in the radial and some have a tri-axial sensor that detects all three. The engineering and physics nerd that I am, I like as much information as I can get. So here you can see now that the sensors with the pipe wall--just another illustration of the three different directions that you can have these sensors running to.

So, what are the types of features or anomalies can the two different types of tools detect? The first and obvious one would be that it's metal loss. This is the type of feature that it was first designed to detect, both on the internal and external surface. Metal loss on the girth weld and seam weld is difficult, too. Now, with narrow axial corrosion, the transverse MFL is a lot better at that, as I previously mentioned. And with the standard MFL tool, it's better with the tri-axial sensor. Now, the biggest difference is that the transverse MFL--you can detect those large cracks, or crack-like defects. And as I mentioned, it requires that larger tool. Both tools can detect deformations such as dents, wrinkles, lamination, occlusion, weld-related anomalies, your regular pipeline components--anything in your pipeline that has ferro magnetic steel, or regular steel. If it has a stainless on part, then basically it will look like errors in the tool. So, T's, hot taps, sleeves, casings, etc.

So, now that we know what an MFL tool is, what it can detect, how do we determine whether a pig run is successful or not? So, I'd like to quote one of our senior mechanical designers. He likes to say that you need to get out what you put in. That's your golden rule number one. You need everything to come out the other end. There's a lot of different mechanical specifications that need to be met for a tool to safely propagate through the pipeline. Things like your bore diameter, your minimum bend radius, your minimum valve bore and T-spacing, velocity excursions. With gas pipelines, especially with elevation changes, you can get--MFL tools have a lot of tool drag. Not only do they have the friction forces of the cups and the brushes on the wall, but the magnetic forces are extremely strong. So, if there's not enough pressure they take and slow down--and ultimately sometimes stop--gas can build up behind it and you can get large velocity excursions where the pig will be going too fast to collect proper data. There's various ways that you can fix that--speed control, etc. But that's not the topic for today.

So, this is what can happen if you have velocity excursions and go too fast. What happened was--you can see the extensive damage here. What happened was this tool, due to over line pressure through the gas pipeline went over 60 miles an hour through 1-1/2 D or extremely tight bends.

So, you can do all you can to properly design a tool but with those kind of forces there's nothing you can do. Over here you can see a 36-inch diameter tool. This is actually a caliper tool, but what had happened was there was a gate valve that was left open about 13 inches. So it was able to get by, but obviously extensive tool damage.

So, not only is it the pipeline vendor, the inspection company's responsibility to make sure that the pig comes out, but it is also obviously the operator's responsibility as well.

So, once you've gotten through the pipeline safely, you also need to make sure that you collected data properly and that all of your electronics is working appropriately. So you need to have your QA testing, your electronics, and your appropriate environment depending on your product, especially if you have a corrosive or a product that has high conductivity like a water or brine solution. You need to have the proper testing. You need to make sure that your sensors ride properly against the pipe wall. That's extremely vital to make sure that your data is appropriate.

So, here is one of the challenges that we have, especially in crude line. This is a very large inch diameter tool. I don't know if you can see. Here are the brushes, so obviously it's very heavily covered in wax. So you can see that the sensors that are here are not going to be able to ride against the pipe wall properly. So that's one of the challenges that you have, especially in extremely waxy lines.

So, and you can see here just a pressure vessel where you need to do your quality assurance testing with your electronics.

So, once you've properly collected all the data, what are you going to do with that again? Once you analyze all the data and you give your report to the client, they decide to go out and dig. They're going to need to make sure that they're digging in the right place. So accuracy is extremely paramount.

So, many of the MFL pigs have inertial navigation systems that map out the pig's progress through the pipeline so that you can just supply a GPS coordinate in terms of where to go dig. And that--as part of that you need a GPS survey done on the line, as well as an AGM placement.

So, this picture here is from the far east here. The pipeline goes actually right down this road and those boxes are above-ground markers that detect the pig's movement through the pipeline. So, as you can see, there's operational challenges in terms of trying to track pig movement.

And then, of course, you want to make sure that you have the correct location where to dig. So, once you've dug the feature out, you want to make sure it's the size that the pig vendor told you. So, how are you going to make sure that it's the proper size?

Well, you need to make sure that you have a sizing model. As I mentioned, the MFL is infered. It is not a direct-measuring of the pipe wall thickness and because of that you need the proper sizing model or algorithm, and testing of your tool to make sure that you are within the proper sizing specifications. As you can see here this is a testing facility and sample defects that you put into the pipe and test your tool through to make sure it is calibrated properly. What is this sizing model algorithm? Well basically, what you do is you have your corrosion, you run your tool through, you have your signals here that you get on whether it's in the different orientations. You take information from those signals, you apply it to--sometimes there is various progression techniques--there's neuro-network algorithm, many different types of physical analyses, and at the end you come up with your defect size, length, width and depth. So it's extremely vital that you have the proper sizing arm.

So, here's an example of a crack. As you can see here on your X axis is your actual depth. So this depth was when you went into the ditch, dug it and physically measured how large the corrosion is--how deep it is. And on the Y axis is what the pig vendor said how deep the corrosion feature is, if it's from the ILI.

So, typically what the sizing specifications are is plus or minus 10 percent on depth. And so that's what these green lines are. And what the sizing specification typically is, it says within an 80 percent confidence. Which means that 80 percent of the time, you are within these green lines.

So, if you have a few defects outside of this, obviously you're going to be extremely worried, but it's important to note that pig vendors can't just change their sizing models to suit specific pipelines. In some cases you can, but it's a dangerous thing to do because then you force your model to look at only specific defects and not all the defects in general.

So, now that we've collected the data, we've analyzed it, what other types of the things that we tell a pipeline operator in terms of reporting? Number one, we are an information service. You paid to get the product, the report is--that the product is only as good as the information that we collect. In terms of reporting timelines, they vary from contract to contract, but typically this final report will come to you within 60 days. What--this differs between all the different pig vendors as well. Now, special requests are possible. It is possible to have a preliminary report done, let's say 72 hours before the run. But all that needs to be organized before, within the contract. And, of course, there is different pricing and things like that.

Basically, the report provides a self-standing snapshot of your pipeline, with a hard copy, and depending on your vendor, you might be given the actual viewing software so you can view all the defects yourself that you have in your line. And as well as tech support for the software and for the different features. And, depending on your vendor, some vendors store the complete data set of your pipeline so that several years down the line if you decide, "Oh, we've got a problem of, say dents, within our line that we want to take a better look at." You can ask the pig vendor to go back and reanalyze that data, which we've actually done for a few companies.

So, here's an example of a dig sheet for a fictitious company. You're going to see Frank's Pipeline Company up here. So here you have your location information in terms of your GPS coordinates, the size of the feature. So the feature that we're looking at today has a peak depth of 48% of the pipe wall and an average depth of 25% in cluster corrosions. Here you have your reference point, picture of your pipe here and this reference to the seam weld. You have your first pressures, your B31G, modified B31G, your affected area here, you've got your very bottom profile, you have your feature with respect to the neighboring pipes with the seam welds listed, as well as your plot position here in red--the feature that we're interested in. And then you've got your initial--your east, west northings, your elevation profiles, and finally a map of the actual defect.

So, obviously, this is a fake pipe. The blue line here represents the pipeline and where it is with this green dot here being where the pipeline feature is. I don't know if some of you recognize the name of the streets--this is from Google Maps, by the way. So, what we do is we overlay our inertial data with the inertial data from Google Maps. So, as you can see right about here is our hotel, so if you closer zoom in, here is the hotel that we're in right now at the corner of E Street and I'm not sure what this one is. But, so this is a real feature. Obviously, you want to make sure that you have proper location and so the photograph provides a lot more information if you actually have to go out and dig.

So, I'd like to end things off with some of the current events that we're doing in terms of what the process that we're doing that we may not have done before with data. So, the first one is--in the past we've always been able to detect dents in pipelines. They have a specific signature in the data, but before it was always just detection. And right now we're able to actually size the depth in terms of your outer diameter of the dent. This is specifically with MFL technology with the tri-axial systems. In addition to detection and sizing of the dent, you can also determine--you can also go back and look at your denting to see if there are actually stress or risers within that dent such as circumferential cracks, corrosion, gouging, etc.

So, how do you size dents with MFL technology? Here is a quote that, I don't know if you can read it. There's been limited success identifying third party damages in MFL tools. MFL tools are not useful in sizing deformations. And that's from ASME B31.8(s) So, obviously, initial expectations. There are three factors that affect dent sizing. Number one is the signal shape repeatable? Is your sensor body over that dent and is it the same for all the dents? So that you'd know what kind of signal you're expecting.

Number two. Do you have enough parameters to correctly quantify the size of the dent? And this comes from the three different MFL sensors that we have that detect the flux leakage in the actual radial and circumferential directions.

Then, finally, which is most important, how do you know that you are sizing properly? You need a library of film dents. And obviously it's very difficult to dent pipe and to test all the kinds of different dents that you have. So, over the past years, we have had both a caliper and geo pig tool that is very accurate at measuring dents. And we have run an MFL tool in the same lines. So we have a library of literally thousands of dents to look for, so that we can actually compare it with what the geo pig did and make sure that the MFL is sizing it correctly. And so when you do that, here is a similar graph that you saw with the MFL corrosions where you have these two blue lines being plus or minus 10 percent--sorry this is an eye of one percent depth there. So, one percent OD--sorry. So, one percent OD on your depth of your dent. So you can see here, at one percent you are 99 percent confident and at half a percent you are 80 percent confident. So, the only way we can do this is because we have a library of defects that we did, so this actual size of this dent is not the size of the dent that you go in and dig and physically measure. It's the size of that we have taken from the caliper tool.

So, here you can see is some data from an actual run. You can see here two dents on the girth weld here and then here. And actually there is some corrosion with that dent. There's going to be some here. So all these different boxes are actually corrosion within that dent feature.

Here is actually some gouging. You can see here there's four different signals here. And this is actually from these four different dents with gouging here that you can see a little bit more clearly there. These four areas are gouging with dents from an excavator.

So, here's an example of a dent that you see here. In the past we would just box it and move on. And actually some operators ask us to go back and take a closer look at these dents, so what we're doing now--this is a 3D view of this dent. And with this specific one that we found on the profile it said there's a sharp spike right there. And what we determined from that spike is that it wasn't long enough to actually be a metal loss corrosion--it was too sharp. So what we are seeing in data on this said that he believed that it was actually a deep, deep crack in the pipeline. And when they went and dug it they found a 3.7 percent OD dent with through wall circumferential crack. Now that was the crack that was orientated throughout the pipe, along the axial of the pipe.

So, I have a movie, but all this takes too long. Apparently, I'm not that good. And at this point I'd like to open the floor to questions from the panel.

Thank you very much.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: Now what we're going to is we've invited the panelists to ask Frank questions. And we have 10 minutes allocated for that, so do any of the members of our panel have any questions that you would like to pose to Frank at this point? Please.

Greg Swank: Frank, you mentioned successful pig runs. I would like to maybe get some feedback from you on what determines a successful pig run. Is it percent coverage? Is it a delta between the actual calls that were made and what you validate in the field? What does actually constitute a successful run? And, secondly, is there a national or international standard for determining what a successful pig run might be?

Frank Sander: Okay. Immediately after the level of success is usually the amount of data collected. Typically in a contract it'll say a specific percentage--99, 95% of data properly collected is a level of success in terms of having the report go out and sort of discuss a little bit there. But, then, in terms of ---with the verification date the--a lot of times the pipeline vendors, the inspection companies are extremely interested in making sure that they can increase their specification of their sizing, make sure that they're within their sizing by getting the numbers back in terms of the actual size of your defects.

In terms of the standard out there, I believe in the afternoon--later on will be a discussion of various statutes out there, but API 1163 is one of the main standards that sort of encompass all of the different aspects of in-line inspection. And in that it includes levels of success.

M: Does that answer your question? Okay. Other questions from the panel? Yes, please.

Bill Flanders: You mentioned that you could identify an area of axial corrosion. In general I think pig technology is great, but I think you have a tendency to oversell your technology. What is your width required for an axial MFL tool?

Frank Sander: Our sizing specifications are within our plus or minus ten millimeters. In terms of the detection threshold it's 10% on the depth and for small pits, in terms of being able to size it properly, it's plus or minus--this changes for all different vendors. I'm just speaking in terms of our specific tools. But, in general, for ours it's plus or minus 15 percent on the depth--I'm sorry 15 percent is the threshold that it needs to be before we can start sizing. And then sizing specifications is plus or minus ten millimeters, and plus or minus 10% depth.

M: Does that answer your question?

Bill Flanders: Yes, I was trying to think in my head trying to think ten millimeters.

Frank Sander: Oh, sorry. That's like .4 something, just a little over .4 inches.

Bill Flanders: A lot of inner axial corrosions are wider than that.

Frank Sander: So you might be looking at a different technology then.

Bill Flanders: The same thing with dents, what's your threshold of detection on it?

Frank Sander: For the MFL tool?

Bill Flanders: Yes, as far as diameter.

Frank Sander: I believe it's half a percent to OD, but it's something new that we're coming out with in terms of its dent sizing. So it could change in the future. I believe it's half a percent, but don't quote me on that.

Bill Flanders: You need to caution operators that they need to validate the tool to verify that the tool is capable of detecting the risk and threats to your pipeline. So, if you have a high D over T pipeline, the dents re-round) very easily, you have very low, shallow bends with cracks in them, you need to use appropriate technology to identify those types of risks.

M: Just so everybody knows, Bill is with the Department of Transportation, Office of Pipeline Safety, Greg is with BP, and when you ask a question identify yourself by name, who you're with and that way we know who is talking. Any other panelists have a question?

Please.

Chris Dash: What is the role of the operator in feedback to better reading your sizing? How do you take the data that we give you and update it?

Frank Sander: In occasions especially where you have a unique situation, say a very thin wall thickness for that diameter or something like that, a lot of times we would love to receive pipe from you, put our own defects in and make sure that we have got the proper wall thickness exactly specified.

That's probably the best thing you can do. But all vendors are very interested in getting feedback, so any kind of information that you send back in terms of, "Here is what we did in the ditch." "Here is the sizing that we did." But not that this is the size of the feature, how you did it--was it laser pig, any kind of data that you collect. The more data we have the better we can serve our pipelines clients that we have.

M: Does that answer your question? Okay. Other questions from the panel? Any other questions? Thank you very much.

Okay. We have three or four questions that came in after they had been integrated into the sets that I have asked, so this one is for Frank Sander. Is there any effort to put the interpretation of MFL pig signals on a fundamental theoretical basis rather than empirical correlations and tests with manufactured defects? I've always wanted to say that sentence.

Frank: Typically before a new tool gets designed there's a lot of obviously mechanical design work, but also some final element analysis work with the magnetics of the situation. And we do theorize defects in terms of what kind of saturation levels are required for this tool, for this configuration, for the size that it needs to be and that's how it gets built. And then once it's built it's tested and verified with the calibrated defects that we put into the pipes.

M: Okay. Any other comments? Please.

Jon Wharf: And the other aspect of the theory that enters into the process will be constraint on the sizing or building process, so the responsive metal loss to the magnetic field has theoretical elements of constraint--how you should model it. You shouldn't allow trends to run against that theory to assessment of the process.

M: Any other comments? Okay. This question is actually for Frank and Jon. Again, please discuss the effects of parent pipe alloy content on MFL and UT inspection. Of particular interest is nickel and chromium alloys.

Frank: Typically when we do this final analysis work and design our magnetic portions of our pigs, we take into account the various types of grades of pipe steel that are out there. We do testing on it and get what's called a BH curve, which basically determines the magnetic properties of that MFL tools operate for in terms of the pipe steel. So if, say, you're designing a kind of new non-standard material that you hope to have to make into your pipeline, the best thing to do would be to send a sample to specific vendors and they can do the required testing to see how much it changes from the other pipe standards, and you can design a tool around that as well.

Jon Wharf: Yeah, that's a reasonable approach. The other thing about ultrasonic inspection, of course, is that the speed of sound of steel is relatively unaffected by alloy content and in fact you can use ultrasonics to inspect non-magnetic steels and mixed steels--so if you have cladding or something like that, you have some complex pipe construction method--then an ultrasonic would be a good choice for that which would be very, very challenging for a magnetic inspection.

M: Okay. Any other comments on that? Okay.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

Well, the audience has some questions here. So, let me start off here. Okay. Frank, all of these questions for the next 25 minutes will come to you initially, but other members, other presenters, or panelists, please feel free to join in on the answers to the questions as we're--and any kind or dialogue you want to have around the questions and answers, that would be great.

So, the first question, Frank. Is there an industry standard for how often pipelines should have an ILI? And first say what an ILI is in case somebody out in the audience doesn't know what that is.

Frank Sander: ILI stands for in-line inspection. It can be an MFL tool, a caliper tool, any kind of tool that you put in a pipeline to get information about the pipeline. And in terms of regulations regarding how often--I think we have a couple panelists here from the DOT that would probably be a lot better able to answer that question than myself, but there are industry regulations regarding that. There's some that are kind of in the process of being adopted and accepted. Within the industry API 1163 but in terms of hard numbers I don't have anything off the top of my head.

M: Does anybody on the panel have something off the top of your head? Anybody? Yes, please.

Jon Strawn, DOT: The code requires a baseline assessment and the initial pigging or assessment that would be pigging or hydrotest or whatever, has to be completed by the governor's deadlines that I talked about this morning. About a 50% for large operators, I think in '04, whatever that number was. And then all of them will be completed by '08. A complete assessment. And then the real assessment would be every--not to exceed five years.

M: Anybody else? Please.

Pat Vieth: I was going to say that five years is for just a liquid side. Extended intervals, seven years for gas.

Jon Strawn: Yeah, I didn't address anything about the gas. I was dealing strictly with liquid lines.

Bill Flanders: Yeah, Frank in his presentation made an excellent comment that an ILI run is a snapshot in time. An operator needs to run the tool to identify his threats before those become an issue with integrity. So he needs to determine what kind of corrosion growth rate--if it can be mitigated, that is one thing. If it can't then he needs to determine what that interval should be.

M: Yes.

Jon Strawn: I think some other requirements of the code is that you have to have this continual assessment to look at the other risk factors and other things that's going on in your pipeline that might prompt you to do another pig run or another assessment at any time. So there are risk factors that could preempt, cause an earlier assessment--integrity assessment. So to just put a hard and fast number on that, I don't think there is a number in the code.

Frank Sander: In terms of monitoring your pipeline, in terms of doing an inspection one year and another the next, what you can do is--a lot of the pipeline vendors--I know PII GE and I believe Rosen can do corrosion growth assessments, so what they do is they compare one--the line that you just did with your previous one and give you a corrosion growth report that you can then take and put into your integrity analysis program that you have. So those are services that some ILI vendors have.

M: With the panel's permission, let's move onto the second question here. Once again, this is for you, Frank. If you came to a pipeline with no recorded history of problems, what pig type would you use first to inspect it?

Frank Sander: I guess that would depend on how well you know the line in terms of what kind of features you've got. Do you have unpiggable valves or those type of valves that have more restrictions in terms of a size smaller than your regular diameter of your pipeline? What kind of bends that you have. If you don't have a great understanding, let's say you just bought another small pipeline company and their version of integrity was this office that's jam-packed full of paper that they wanted you to put a match to, and you are basically are starting from scratch.

We would probably want to first of all start with the simple gauging tools to make sure you find out what kind of bends, what kind of shape they come in, do they come out of the pipeline afterwards. Figure out that kind of thing and just slowly move up, maybe do a geometry caliper tool that has an inertial navigation system in it so you can actually physically map out your pipeline so you know where it is exactly. Then just sort of move up from there.

M: Okay. Anybody have anything to add? Okay. Question number three. How do you assure that the pipe is demagnetized after an ILI run?

Frank Sander: I guess I would ask a question to that in terms of how--why would you need a demagnetization? My guess about that would be if we need to go in and do any kind of repairs, if you ask any kind of welder, welding on magnetized pipe and steel is extremely difficult. We have that daily occurrence when we test our tools. So, what they have is there are systems out there that can properly demagnetize a local area of pipe, if you're doing any kind of work on that. In terms of systems that are industry standard in terms of making sure that you have proper demagnetization so that you can do your repair work within the proper evaluations.

M: Anybody have anything to add? Okay. Along the same vein; are residual magnetic effects known to cause additional corrosion in local areas? That is, pipe bends.

Frank Sander: I've personally never heard of having a residual magnetization in the pipe as being a cause of any kind of further damage or corrosions in the pipeline. There could be operational constraints like I mentioned in terms of magnetized pipe with welding and that, but in terms of having natural corrosion because of the magnetism, I've never heard of that. It doesn't affect your environment in terms of what causes the corrosion.

M: Okay. Anything to add by anybody on the panel? Please.

Bill Flanders: Yes, I believe the federal government in the Colorado school of mines is studying the effects of magnetic--strong magnetic fields on the pipe with some aspects of corrosion growth. There is no firm conclusion from that study.

Chris Dash: There is a paper at the IPC in Calgary just recently that talked to that very subject.

M: IPC stands for? International Pipeline Conference. Okay. Anybody else?

Okay. Next question. Does detection accuracy of MFL tool vary with size of defect?

Frank Sander: Yes, it does. Different vendors have different sizing specifications. The typical specification that you have, you have your minimum detection threshold--what's the smallest defect that you can detect? And then they've got sizing specification in terms of what's your error interval in terms of saying how long it is, how wide it is, how deep it is. Many times that's about plus or minus 10 millimeters, or just under .4 inches. Plus or minus 10% on depth. You also have a probability of identification which is involving API 1163. That's how well you can identify the different anomalies that you do find in the pipeline, including pipeline features.

In terms of tool size, typically it--all different tools are different so what I would--I guess to answer that question is which ever pig vendor that you're looking at, take a look at their spec sheet for that particular size of tool that you're looking at doing. Don't look at a general spec sheet, you need to get specific because--especially with tool diameter and tool sizes, specifications can change.

M: Okay. Anybody have anything to add to that? Please.

Jon Wharf: I would just like to also add this— As you change diameter or as you change bend pass and kick you will see that levels affect your ability to inspect different wall thickness. Not only will the different tools behave differently in terms of how well the defects will be characterized for that particular tool. But as you go down to small diameters in particular, if you haven't got a lot of volume inside the pipe to drive them out you tend to have more restrictions on your--the wall thickness range that you can effectively inspect).

Pat Vieth: I have a third point. I touched on this briefly earlier, this is also a function of the type of pipe you have. I mentioned earlier that in pipe types like seamless pipe where it's not a control rolled steel, you get a lot more noise in the signal so your detection and sizing capabilities can be affected by limiting factors like that also.

M: Other comments from anybody? Okay, next question. Since it is clear that "high resolution MFL" is the first choice for integrity assessments, could you provide estimated costs for different projects that you have worked on?

Frank Sander: Every project and contract is different. And so every pipeline is different, so it's I believe the pipeline mission--somebody in one of the previous presentations noted that basically you have a situations that need some costing change regardless of--I think I'll let it go at that.

M: So, the answer is "No."

Pat Vieth: I think that just maybe to put it in perspective that I think the question along the line of what it would cost to run a survey, it's fair to say that's on the order of a few thousand dollars per mile. It depends on the size and diameter, the length, mobilization. But it's on that order of magnitude.

Frank Sander: Was there talking in Alaska about that?

M: Chris, it could be more in Alaska?

Chris Dash: Yes, it could be quite a bit more. Especially mobilization.

Chirs Dash: I remember seeing some things on a website called Cost Corrosion; it was a study by NACE, I believe, put together. I believe seeing something about the cost of dispatching per mile but I'm not sure how true that information, how accurate it is for Alaska. You could look it up on the website.

Frank Sander: I would like to say that the three main factors are the type of tool that you're running, the diameter of it, and the length of it, and then as well the mobilization cost.

M: Anything anybody else wants to say on this topic? Okay. Next question. In Pat Vieth's presentation, so listen closely Pat, he showed a pipeline anomaly that was challenging for a human to detect. What is the state of the art available today or in the near future in machine (non-human) identification of pipeline anomalies? First of all, did he accurately capture your talk?

Pat: I think so. I might have to refresh Frank on what it was. What it was, it was a gouge on the about 3 o'clock orientation of pipe for which there was no detection from the type 1 sensors, but the type 2 sensors showed some minor noise. And it's not something that through data analysis of several hundred miles of pipe would pick up, but if that location were to fail in the future you could go back and say, “See, there is something in the data.” But it was in the north threshold, I think you recall that plot.

Frank Sander: Historically, years ago with less computing power and not as good automated algorithms for searching through the data to look for features, a lot of times it was extremely--analysts had to spend hours and hours looking at it. So a lot of times they would not look at something as long as they wanted to, just because of the time restraints and the vast amount of data they had to go through.

Now with better automated algorithms, analysts have more time to properly look through, and I would say that today that we have a lot better chance of finding these features that are closer to the noise level of the data that you’re collecting. Possibly find smaller and smaller features.

M: Okay. Other comments on that?

Jon Wharf: Historically, in any kind of computing process the challenge has been to match it with the human analysts with having greater possibility so you get to a chance of a computer doing better than human analysis.

M: Any other comments? Okay. Next question. Is MFL an appropriate tool for detecting metal loss in a three phase flow line? And the second part of the question--if not, what tool do you recommend?

Frank Sander: I know we’ve done work with three phase lines. The challenge with that is typically with our MFL tools, if there is a problem of speed excursions and in terms of a gas pipeline, we would have speed control with it which can allow gas to bypass. But in a three phase line because there is oil or what have you mixed with gas, you cannot use speed controls. So that means that you really want to know the information regarding your elevation changes.

So there’s a few factors that you need to communicate with and have a dialogue with between the ILI company and the pipeline company, but, yes, three phase lines have been inspected with MFL.

M: Okay. Other comments? All right. Next question. How should you control the velocity of the smart pig in the pipeline?

Frank Sander: I should have a computer. I can just try it. But for gas lines where you do have gas velocities in excess of 10 to 13 meters per second, and with the tool speed you can only properly collect data at 4 meters per second. There’s a big difference there. And instead of having the client pull back in terms of the pressure, what you can do is have a gas bypass. And this is only in the case of the fairly large pipe diameters. I believe 24 inches and above in terms of BJ tools. I don’t know about some of the other vendors, but in terms of speed control. So what happens is the pipe body that has the magnets on it, the sensors, has a hole down the middle and the gas comes up from behind through the--behind the previous module and enters that hole. And the bore has a valve that can open and close depending on how fast the pig is going. So the pig is detecting that it is going faster or too fast in a specified amount, it will open up the space to allow more gas to bypass through and hence slow the pig down.

M: Any other comments on that question? Okay. Next question. How clean does a pipeline have to be to be smart pigged?

Frank Sander: It depends on the technology. For MFL you can have quite a bit of debris on there, obviously the one example that I had of the large inch diameter pig with all the wax on, the sensors still have to go against the pipe wall, the brushes still need to be in contact with the pipe wall, but it can get pretty dirty in terms of the environment. With the UT pig, the levels of cleanliness need to be a lot higher. So it also depends on the technology.

M: Any other comments from the panel on that?

Jon Wharf: I just agree with that remark. One of the advantages of magnetics systems is to survive in very unpleasant environments. And one reason for that is the same thing that I can speak to some of these sensors that they grip the magnetics along the pipe wall that really likes to put steel to steel on the end of those bristles; they like to hang on to the pipe wall pretty hard.

Frank Sander: I think I would add in addition to that comment, MFL tools tend to have a slightly higher drag than other tools because of the magnetic force of traction that it has. Not only the friction force, but also the magnetic force.

M: Okay. Any more from you, Jon? Okay. Any other comments from the panel? Okay. I have a little bit of a speech to make on this question here, but if we get to the question at the very end. The question on the card: I won't disagree with the assertion of your bullet point "The product is only as good as the information you collect." I do contend, however, that a major limitation to the product quality also comes from the quality of the analysis and sizing process firmware and similar post run tasks. Your comments, please.

Frank Sander: I would agree exactly with that. In terms of having an MFL tool run, you need every step to happen for the final product or report to be accurate and all parties happy. So you collect all the data, the pig survives, everything is good. Your field crews are happy, your mechanical guys are happy, electrical guys are happy, and then the analysts are sitting there looking at the data and they're happy, but the guys that you have creating the sizing out with them would actually determine what the numbers we're going to be telling the clients. If there is something wrong with that, then your report is flawed. So it's extremely vital to have from start to finish, proper quality checks on all the various aspects of running the MFL tool. And that last part, in terms of the sizing model, is something that a lot of people forget about.

M: Okay. I know this is going to break your heart, but this is the last question. Do suspended solids affect testing with the MFL tools?

Frank Sander: Sort of similar to the previous question regarding cleanliness, suspended solids don't have an effect simply because, like Jon had mentioned, the magnetic force really wants those steel brushes to stick to the pipe wall, so unless there is an extreme case of extreme wax on the line, we'll typically have very good compliance.

M: Okay. Any other comments?

Jon Wharf: Okay just to clarify that. The picture--had a good picture of a pig coming out that was all waxed up, and that the typical effect is not to stop the magnetic circuit, to hold the sensors off the wall, but those magnetic sensors are not touching the wall. Then you're not really inspecting the pipe at all, you're actually inspecting the wax layer. So that's the only way that suspended solids are really going to have an extraordinary effect.

M: Okay. Any other comments? Nothing? Okay. Frank, thank you very much.

Frank Sander: Thank you.

M: We have three or four questions that came in after they had been integrated into the sets that I have asked, so this one is for Frank Sander. Is there any effort to put the interpretation of MFL pig signals on a fundamental theoretical basis rather than empirical correlations and tests with manufactured defects? I've always wanted to say that sentence.

Frank Sanders: Typically before a new tool gets designed there's a lot of obviously mechanical design work, but also some final element analysis work with the magnetics of the situation. And we do theorize defects in terms of what kind of saturation levels are required for this tool, for this configuration, for the size that it needs to be and that's how it gets built. And then once it's built it's tested and verified with the calibrated defects that we put into the pipes.

M: Okay. Any other comments? Please.

Jon Wharf: And the other aspect of the theory that enters into the process will be constraint on the sizing or building process, so the responsive metal loss to the magnetic field has theoretical elements of constraint--how you should model it. You shouldn't allow trends to run against that theory to assessment of the process.

M: Any other comments? Okay. This question is actually for Frank and Jon. Again, please discuss the effects of parent pipe alloy content on MFL and UT inspection. Of particular interest is nickel and chromium alloys.

Frank Sander: Typically when we do this final analysis work and design our magnetic portions of our pigs, we take into account the various types of grades of pipe steel that are out there. We do testing on it and get what's called a BH curve, which basically determines the magnetic properties of that MFL tools operate for in terms of the pipe steel. So if, say, you're designing a kind of new non-standard material that you hope to have to make into your pipeline, the best thing to do would be to send a sample to specific vendors and they can do the required testing to see how much it changes from the other pipe standards, and you can design a tool around that as well.

Jon Wharf: Yeah, that's a reasonable approach. The other thing about ultrasonic inspection, of course, is that the speed of sound of steel is relatively unaffected by alloy content and in fact you can use ultrasonics to inspect non-magnetic steels and mixed steels--so if you have cladding or something like that, you have some complex pipe construction method--then an ultrasonic would be a good choice for that which would be very, very challenging for a magnetic inspection.

M: Okay. Any other comments on that? Okay.

Inline Inspection using Magnetic Flux Leakage Technology

Frank Sander

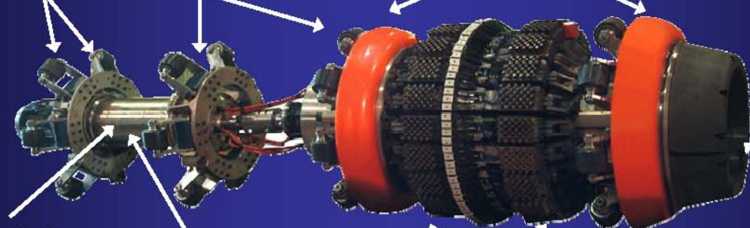
BJ Pipeline Inspection Services

Intelligent Pigging of Pipelines Conference
Anchorage Alaska - November 13th, 2006

Topics of Discussion

- Brief description of Magnetic Flux Leakage (MFL) technology
  - Standard and Transverse (TFI) MFL
  - Sensor types, orientations and resolution
- What determines a successful MFL pig run?
  - Important MFL pig specifications
- Pipeline defect types that can be detected, identified, and or sized by the different MFL technologies
  - Metal loss, metal gain, deformation, pipe mill defects, etc.
- MFL inspection reports and dig sheet example
- Current advancements of MFL technology

BJ MFL VECTRA™ Tool

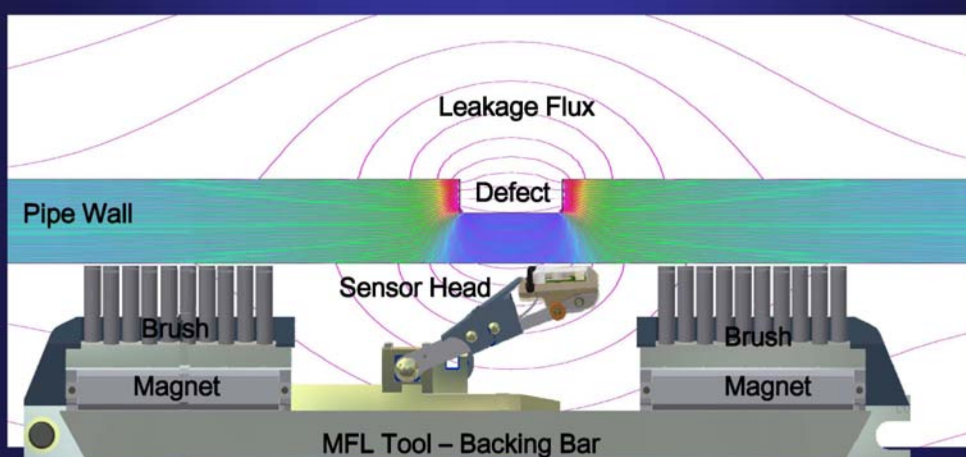


MFL Inspection Tools

MFL Inspection Tools

BJ Pipeline Inspection Services

Principle of Magnetic Flux Leakage



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Standard and Transverse Magnetization

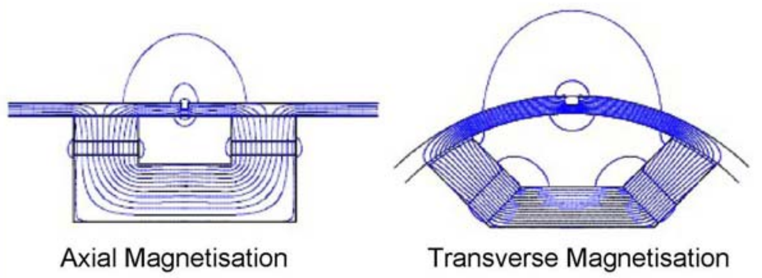

Figure 2: Traditional MFL technology (left), the magnetic flux is parallel to the longitudinal axis of the pipe. CMFL technology (right), the magnetic flux is in the circumferential direction.

- THE EVOLUTION OF AN IN-LINE INSPECTION SOLUTION: AXIAL FLAW DETECTION
  - Thomas Beuker, ROSEN Technology and Research Center
  - Bryce Brown, ROSEN USA

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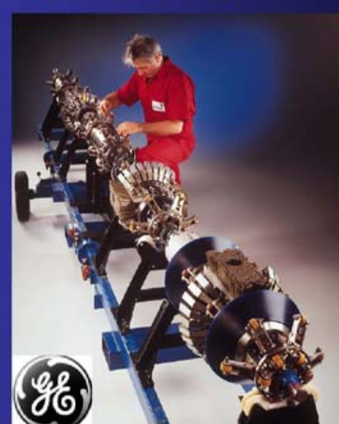
Transverse MFL Tools

56'' Transverse MFL Tool - NGKS



Transverse MFL Tool – General Electric

6'' Transverse MFL Tool - Rosen

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Transverse MFL Tools

10'' / 12'' Transverse MFL Tool
Intratech Inline Inspection Services

BJ Pipeline Inspection Services

Standard vs Transverse MFL

Standard MFL

- Magnetizes pipe in axial direction (Sensor signal of metal loss defect larger for width rather than length)
- Difficulty detecting narrow axial corrosion
- Velocity restrictions (9mph max)
- High magnetic pipe saturation levels - Wall Thickness (1inch max in some cases)
- Very good sizing accuracy for metal loss defect dimensions
- The smaller the tool, the more difficult it is to saturate pipe steel

Transverse MFL

- Magnetizes pipe in circumferential direction. (Sensor signal of metal loss defect larger for length rather than width)
- Can detect narrow axial corrosion and large cracks
- Velocity restrictions (traditionally lower than standard MFL tools)
- Wall thickness limitations due to pipe saturation difficulty. (up to 0.6'' typ max)
- Feature detection and sizing accuracy decreases due to non-linear pipe saturation
- The smaller the tool, the more difficult it is to saturate pipe steel

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Standard/Traditional vs High Resolution?

- What are the MFL Tool Specifications that determine:

  1. What type of defects can be detected?
  2. The smallest defect that can be detected?
  3. How accurately can the defects be quantified?

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Standard vs High Resolution?

- Magnetization orientation and magnetization levels
  - Axial vs transverse magnetization
  - Magnetic flux density of pipe at least 1.7 Tesla
- Sensor density and sampling rate/frequency
  - What is the distance between sensors around the tool? High Resolution – less than 12mm (0.47'')
  - Distance between data points recorded by the tool High Resolution – less than 5mm (0.2'') at maximum speed
- Sensor technology and sensor orientation
  - Induction coils or hall element sensors
  - Sensor orientations can be in axial, radial and circumferential directions

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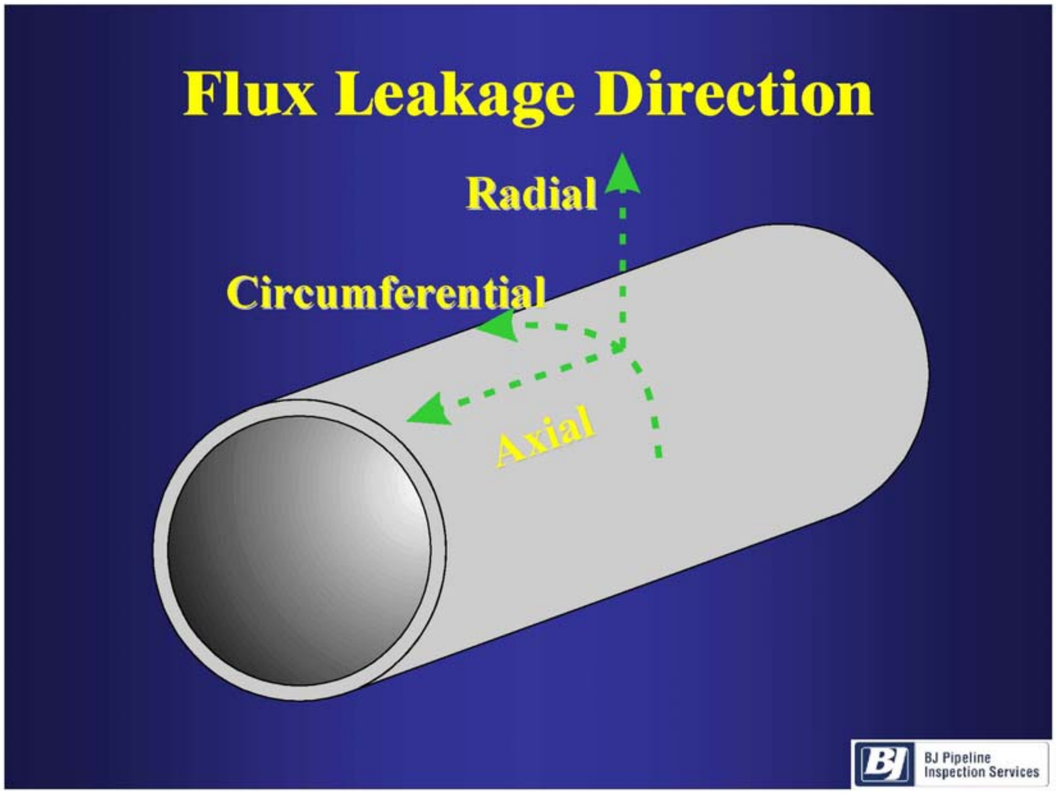

Flux Leakage Direction
Radial
Circumferential
Axial
BJ Pipeline
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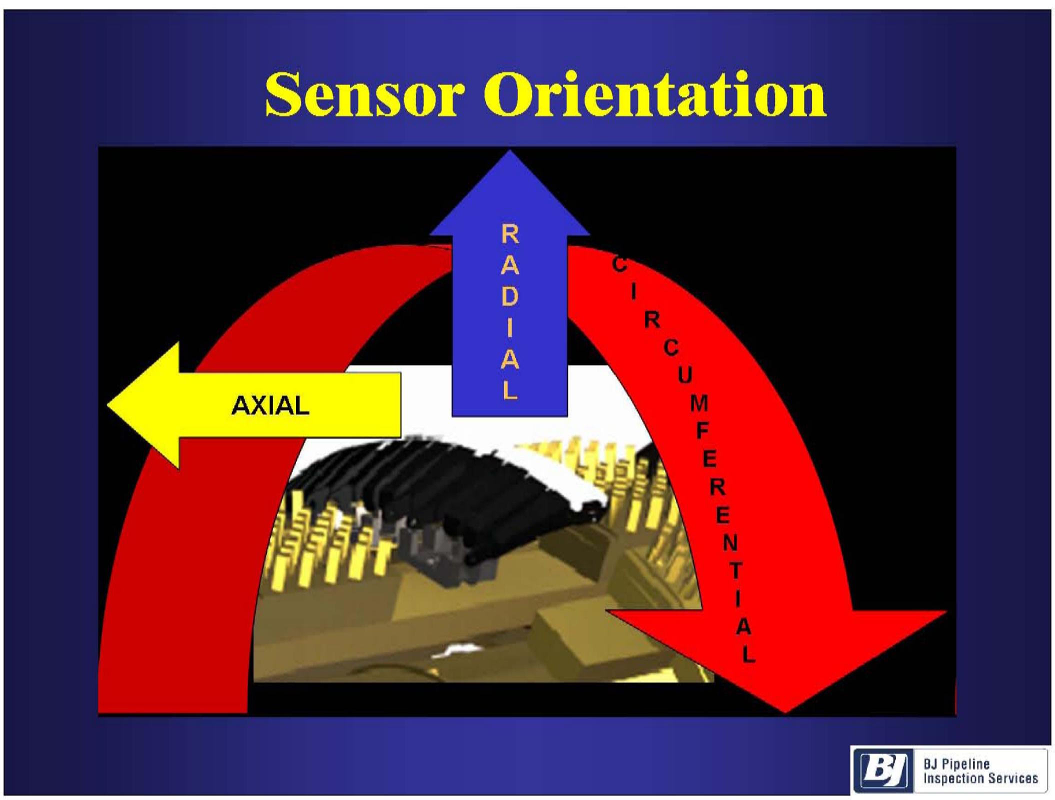

Sensor Orientation
RADIAL
AXIAL
CIRCUMFERENTIAL
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Pipeline Anomalies and Features that can be Detected with MFL Technology

Standard MFL

- Metal loss corrosion (Internal and external)
- Metal loss on girth weld, and seam weld
- Narrow Axial Corrosion (Better with Tri-Axial)
- Dents, wrinkles/buckles
- Lamination, inclusions, mill-related anomalies
- Pipeline components, valves, tees, hot taps, sleeves, casings, flanges, etc.

Transverse MFL

- Metal Loss Corrosion (Internal and external)
- Metal loss on girth weld, and seam weld
- Narrow Axial Corrosion
- Large Cracks, and Crack-Like Defects
- Dents, wrinkles/buckles
- Lamination, inclusions, mill-related anomalies
- Pipeline components, valves, tees, hot taps, sleeves, casings, flanges, etc.

What Makes a Successful MFL Pig Run?

- Mechanical Survival
  - Minimum continuous and local bore diameter, minimum bend radius, minimum valve bore and tee spacing, velocity excursions (bends), proper pig launcher, and receiver traps, product properties, etc.

What Makes a Successful MFL Pig Run?

- Electrical Survival and Data Quality
  - QA testing of electronics in appropriate environment, proper sensor ride on pipe wall, velocity excursions, magnetic saturation of pipe, etc.

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What Makes a Successful MFL Pig Run?

- Location, and Sizing Accuracy
  - Inertial Measurement Unit, GPS survey, AGM placement
  - Sizing model development with calibration defect library

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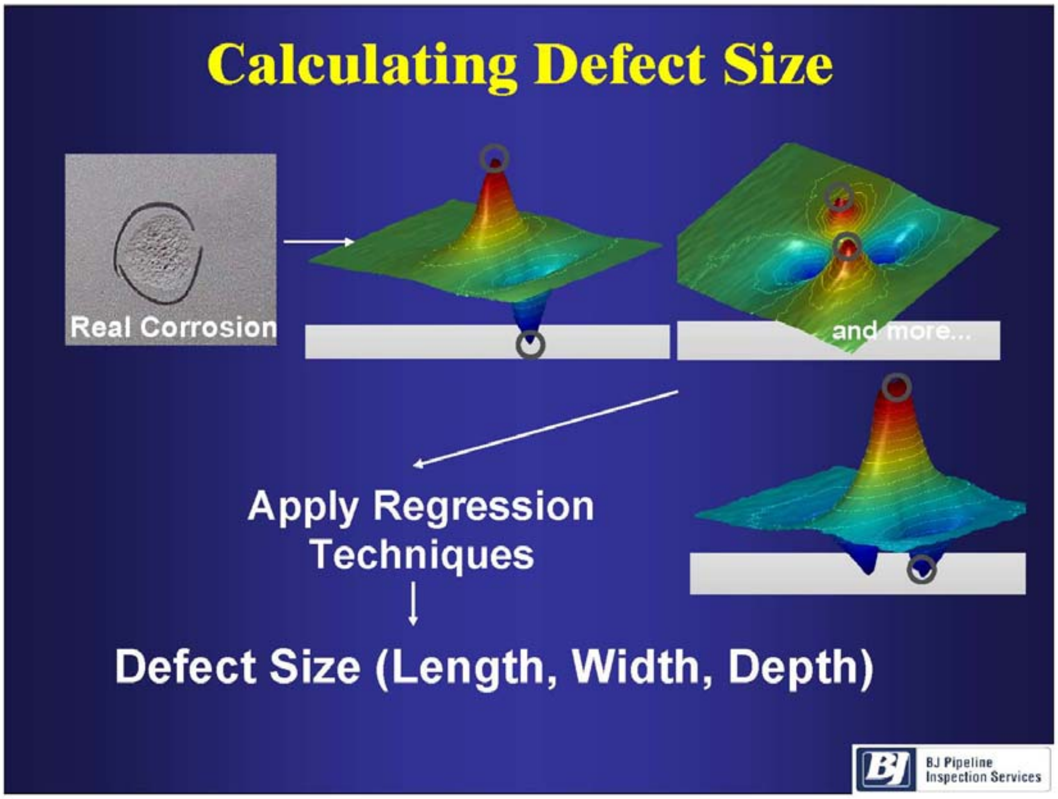
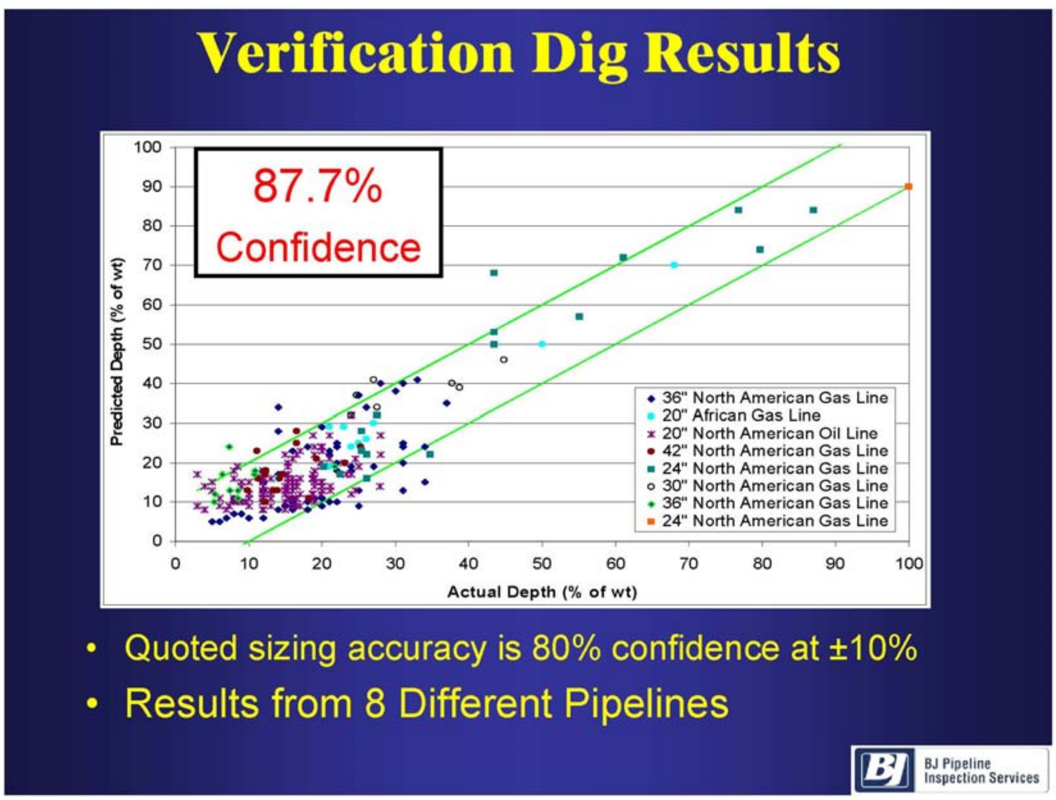

Calculating Defect Size
Real Corrosion
and more...
Apply Regression Techniques
Defect Size (Length, Width, Depth)
BJ Pipeline Inspection Services


Verification Dig Results
87.7% Confidence
Predicted Depth (% of wt)
Actual Depth (% of wt)
36" North American Gas Line
20" African Gas Line
20" North American Oil Line
42" North American Gas Line
24" North American Gas Line
30" North American Gas Line
36" North American Gas Line
24" North American Gas Line
Quoted sizing accuracy is 80% confidence at ±10%
Results from 8 Different Pipelines
BJ Pipeline Inspection Services

MFL Reporting

- Inline Inspection companies are an <u>Information Service</u> The product is not the pig, but the final report
- The product is only as good as the information we collect: Tools (sensors, IMU, odos), field crews, AGMs, GPS survey, "As-builts", sizing model, and expectations
  - Reporting timeline, criteria, report listing formats
  - (sorted tables, plots, distributions, etc…)
- "Special requests" are possible
- Provide a self-standing "snapshot"of the pipeline
  - Paper hardcopy and digitally (software)
- Tech Support and keeping complete data set on file

BJ Pipeline Inspection Services

Individual Inspection Sheet

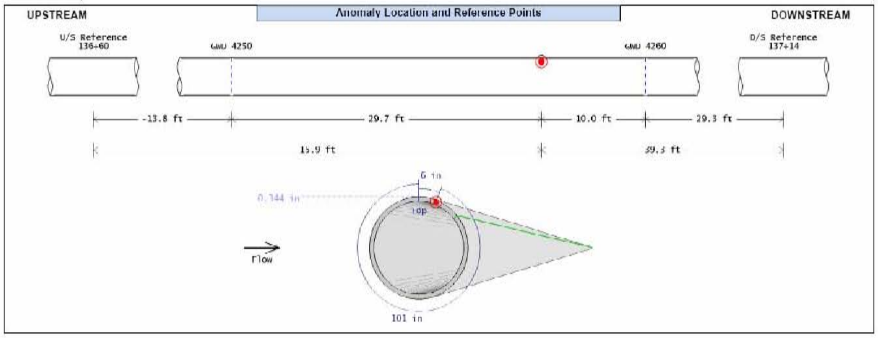
Client:	Frank's Pipeline Company	Run Date:	October 10, 2006	Projection:	State Plane
Project:	A1 - H2 24" Inspection	Location:	Anchorage to Hilton	Datum:	NAD 27
				Zone:	Alaska Zone 4 (TM)

Anomaly: **CLS 2476**

Location		Size/Character		Reference Points	
BJ Chainage:	13,745.6 ft	**Peak Depth:**	48 %WT	**U/S Frank Co. Weld ID:**	N/A
Frank Co. Area:		**Average Depth:**	25 %WT	**U/S BJ Weld #:**	4250
Frank Co. Chainage:	13,675.5 ft	**RPR mB31.G [SMYS]:**	1.02	**Distance to U/S BJ Weld:**	29.7 ft
Datum:	NORTH AMERICAN 1927, Alaska	**Length:**	3.39 in	**Distance to D/S BJ Weld:**	10.0 ft
Zone:	Alaska Zone 4 (TM)	**Width:**	11.04 in	**Joint Length:**	39.6 ft
Northing:	1,811,781.1 m	**Wall Surface:**	External	**U/S Reference:**	136+60
Easting:	207,662.9 m	**Clock Position:**	12:45	**Distance to U/S Reference:**	15.9 ft
Elevation:	30.8 ft	**Pipe Description:**	Nominal WT X60	**D/S Reference:**	137+14
Latitude:	70.252685°	**Wall Thickness:**	0.344 in	**Distance to D/S Reference:**	39.3 ft
Longitude:	148.534868°	**Pipe Diameter:**	34 in		
		SMYS:	60,000 psi		
		MAOP:	550 psi		

Comments: (0.0127+0t)*(0+3t)

Anomaly Location and Reference Points



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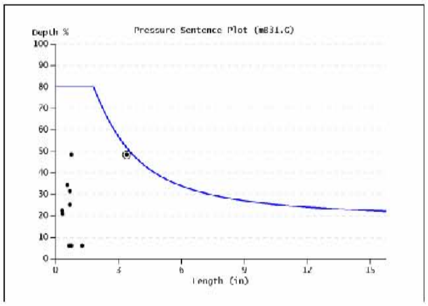
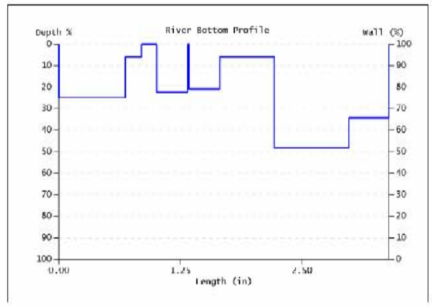
Anomaly: **CLS 2476**

Method	Burst Pressure	MAOP	FOS	RPR
B31.G [SMYS]	1,193 psi	550 psi	2.17	0.98
mB31.G [SMYS]	1,233 psi	550 psi	2.24	1.02
Eff. Area [SMYS]	1,320 psi	550 psi	2.40	1.09





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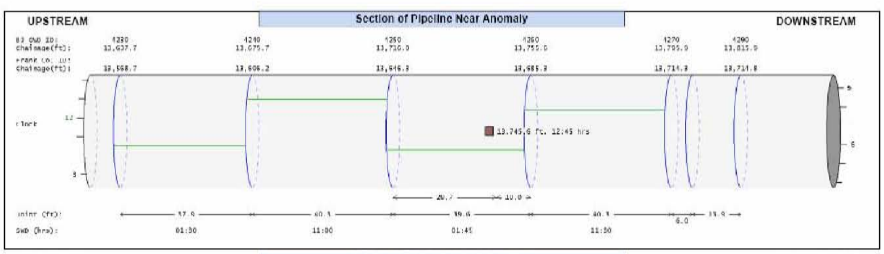

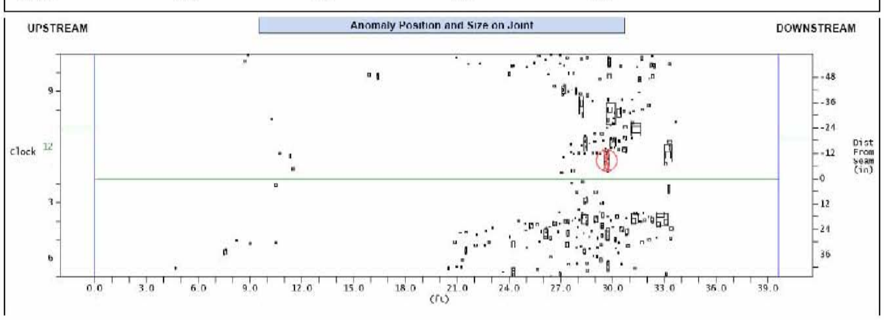

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Anomaly: **CLS 2476**

Legend of Symbols

Anomaly: CLS 2476

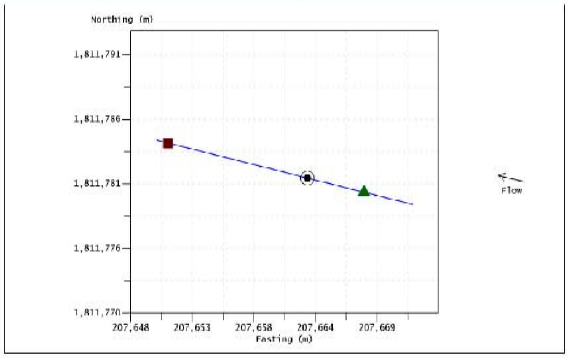
Northing:	1,811,781.1 m	Chainage:	
Easting:	207,662.9 m	BJ:	13,745.6 ft
Elevation:	30.8 ft	Frank Co.:	13,675.5 ft

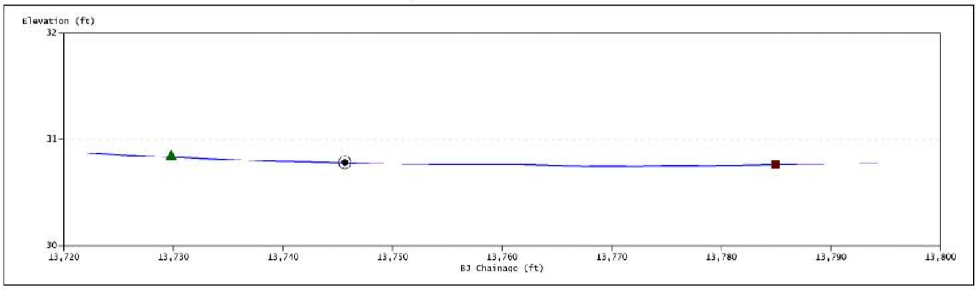
U/S Reference: 136+60

Northing:	1,811,780.0 m	Chainage:	
Easting:	207,667.6 m	BJ:	13,729.8 ft
Elevation:	30.8 ft	Frank Co.:	13,660.0 ft

D/S Reference: 137+14

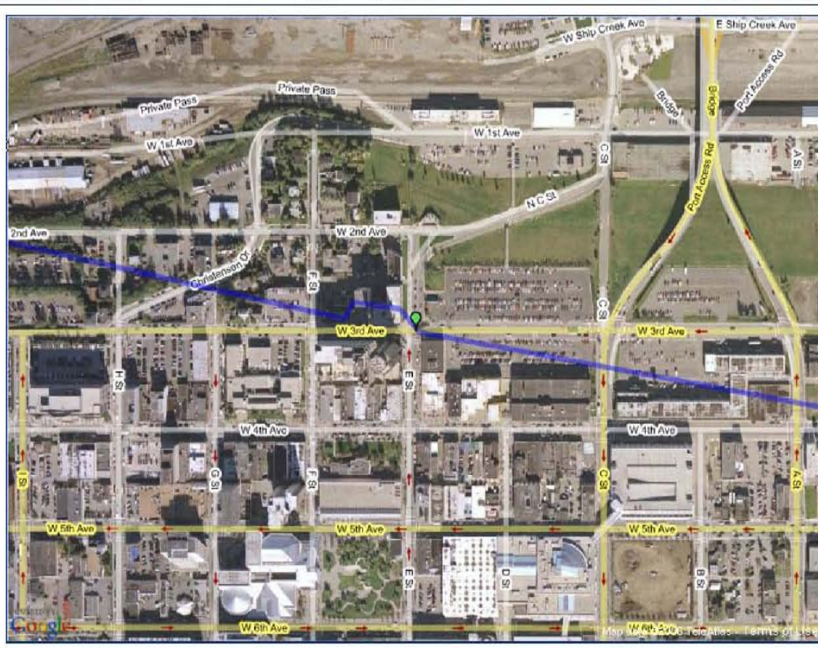
Northing:	1,811,783.9 m	Chainage:	
Easting:	207,651.4 m	BJ:	13,784.9 ft
Elevation:	30.8 ft	Frank Co.:	13,714.0 ft





Individual Inspection Sheet

Client:	Frank's Pipeline Company	Run Date:	October 10, 2006	Projection:	State Plane
Project:	A1 - H2 24" Inspection	Location:	Anchorage to Hilton	Datum:	NAD 27
				Zone:	Alaska Zone 4 (TM)



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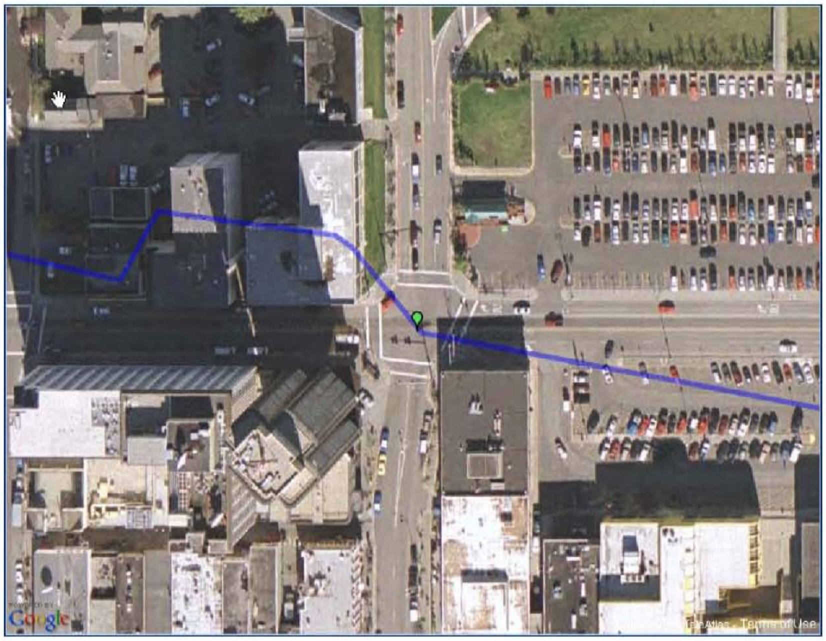


Current Advancements in MFL Technology

BJ Pipeline Inspection Services

Applying New Thinking to Existing Technology

- Detection and SIZING of dents with Tri-Axial MFL technology
- Additional to understanding dents within VECTRA data there is also combined damage, and specifically mechanical damage.
  - Optimized sensor ride through the dents allows for detecting features within the dents.
  - Some of these features combined with denting are:
    - Cracks
    - Gouges
    - Corrosion

BJ Pipeline Inspection Services

Dent Sizing with MFL Data?

"There has been limited success identifying third-party damage using MFL tools, MFL tools are not useful in sizing deformations" (ASME B31.8S)

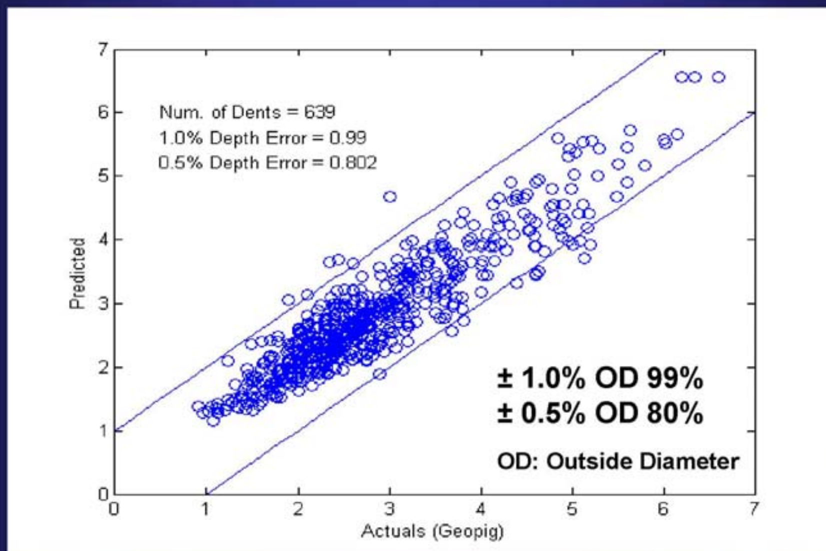
Industry expectations of technology need to be updated.

3 Factors for Dent Sizing with MFL Data

- Is the Signal Shape of the Dent Repeatable?
  - Sensor ride the same over all dents
- What parameters are used?
  - 4 Sensor types to use for quantifying length, width, and depth of the dent. Axial, radial, circumferential, and ID / OD discrimination.
- Database of known Dents for Algorithm Training and Verification?
  - 10 years of inspection using both caliper and Tri-Axial MFL pigs in the same pipeline.

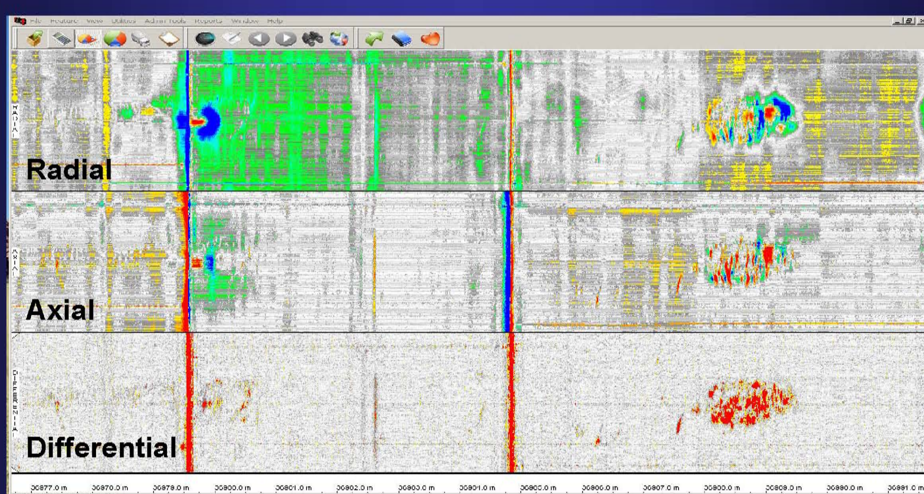
BJ Pipeline Inspection Services

MFL Dent Sizing Accuracy



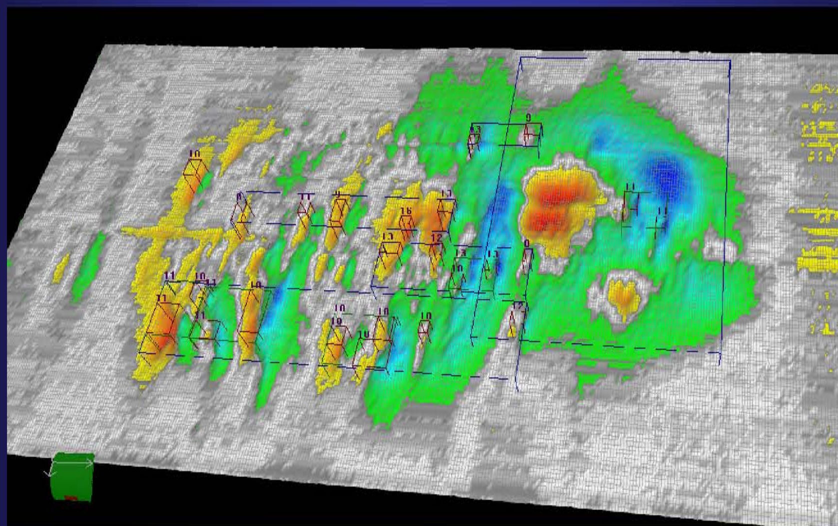
BJ Pipeline Inspection Services

Dent on Girth Weld, Dent with Corrosion



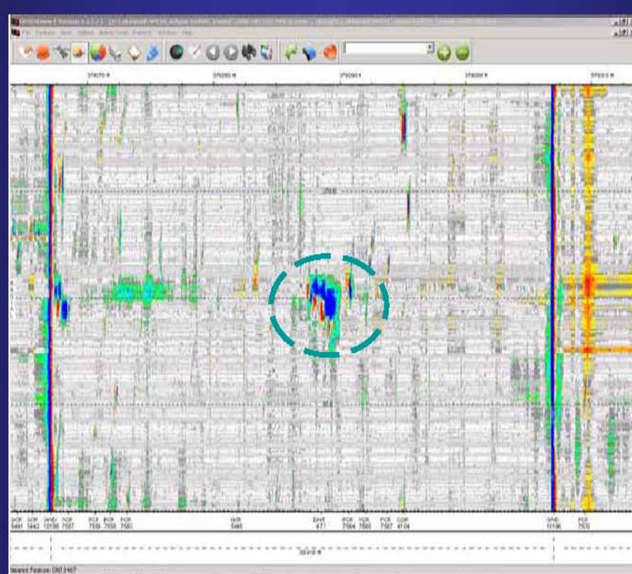
BJ Pipeline Inspection Services

Dent on Girth Weld, Dent with Corrosion



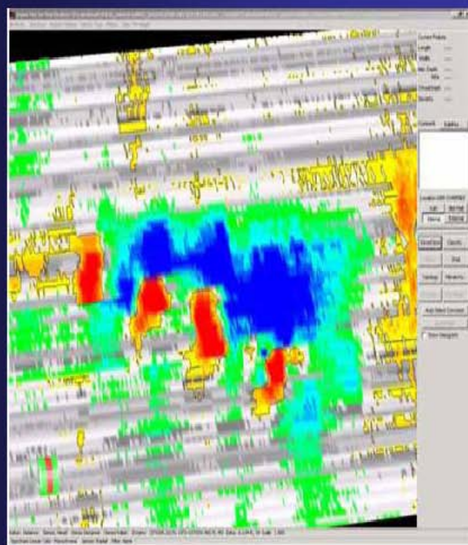
BJ Pipeline Inspection Services

Top of Pipe Mechanical Damage/Gouge Multiple Dents



BJ Pipeline Inspection Services

Top of Pipe Mechanical Damage/Gouge Multiple Dents



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Top of Pipe Mechanical Damage/Gouge Multiple Dents

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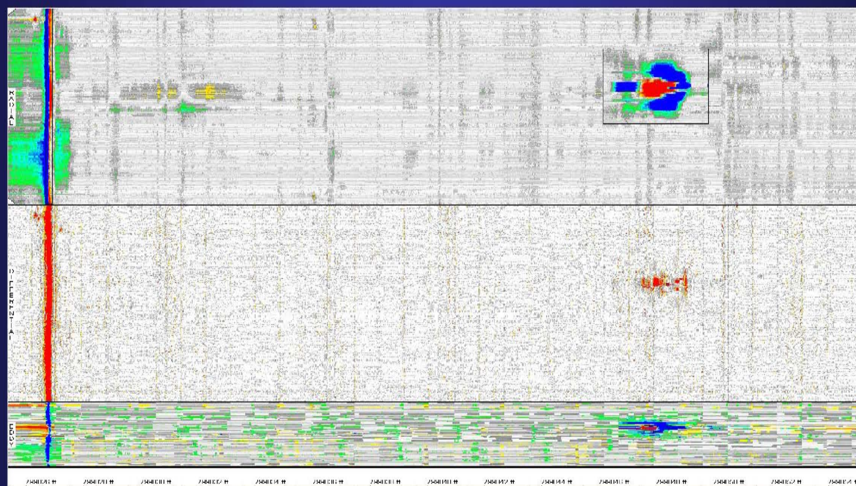
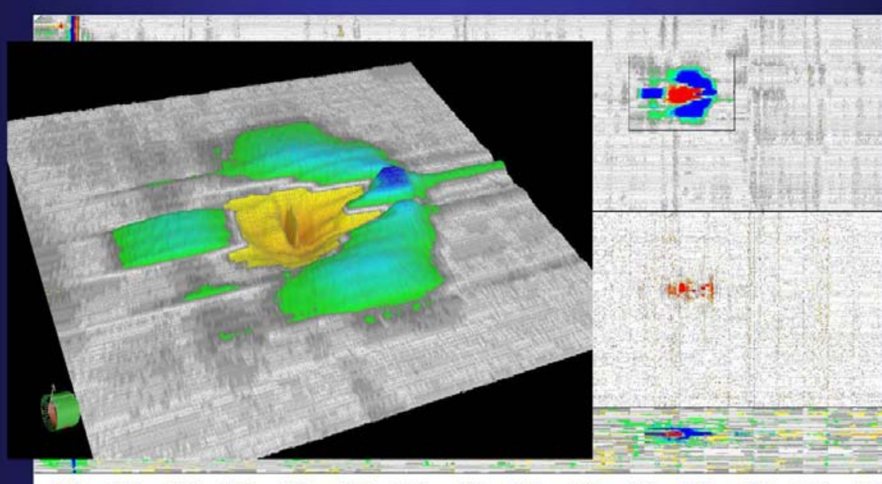
Benefits of Further MFL Dent Analysis



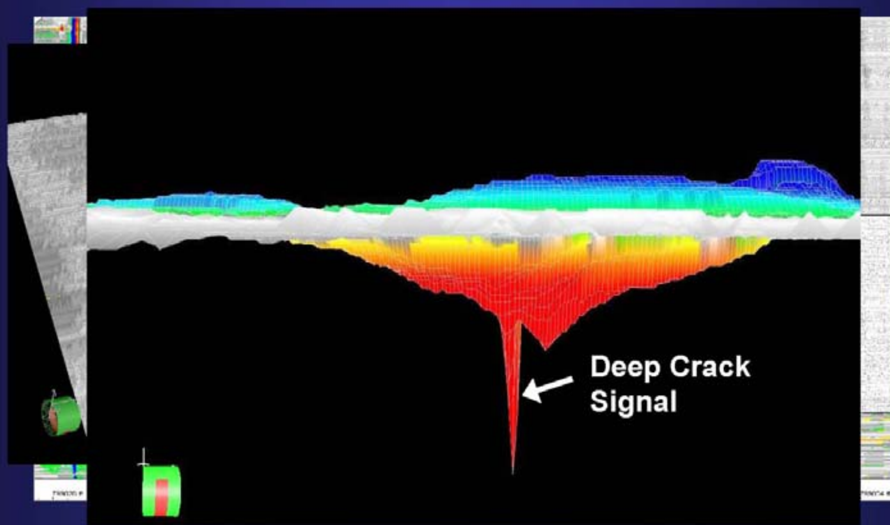
BJ Pipeline Inspection Services

Benefits of Further MFL Dent Analysis



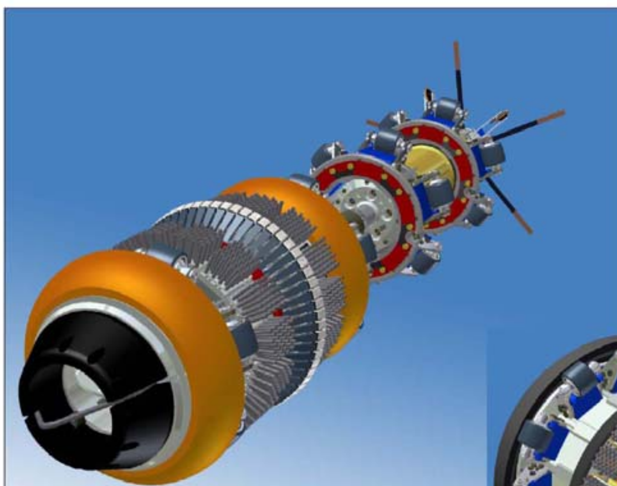
BJ Pipeline Inspection Services

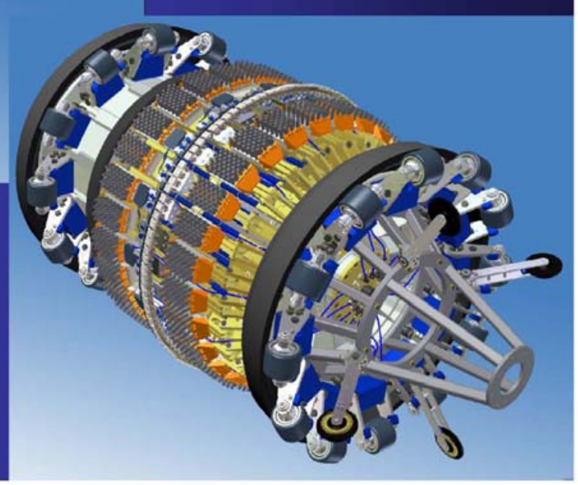
Benefits of Further MFL Dent Analysis



BJ Pipeline Inspection Services

Questions & Answers





Thank-You!!

APPENDIX G

INTELLIGENT PIGGING CONFERENCE PRESENTATION 2

ULTRASONIC TOOLS IN PIPELINE INSPECTION – A REVIEW OF THE TECHNOLOGY

JON WHARF OF GE PII

ABSTRACT OF PRESENTATION 2

Ultrasonic Tools in Pipeline Inspection – A Review of the Technology

Speaker Name: Jon Wharf, Analysis Technical Leader

Company Name: GE PII

Website URL: **www.gepower.com/PII**

Type of Business: GE's pipeline inspection and integrity services provide a comprehensive range of reliable Metal Loss, Crack Detection, Cleaning and Mapping Capabilities with over 25 years of engineering and consultancy experience in the oil & gas industry.

Jon Wharf will provide a brief description and function of ultrasonic tools. Topics of discussion will include:

- Planning and preparation for an in line ultrasonic inspection (pig launchers/receivers, cleaning, batching, etc.);
- Strengths of ultrasonic inspection;
- Contrasts with other inspection technologies;
- Analysis and interpretation of ultrasonic data; timescales and deliverables;
- Field investigation and correlation following ultrasonic inspection.

TRANSCRIPT OF PRESENTATION 2

We are now going to have presentation number two. And, once again, this will be a 30 minute timeframe. Twenty minute presentation, 10 minutes for questions and answer. And it's by Jon Wharf. And Jon is with GE PII, and he will be discussing (ahem--I always get a little choked at this point in the presentation) will discuss ultrasonic technology, or UT.

Jon has been with GE PII in Canada since 2002 as an analysis technical leader. He has a Bachelor of Science degree in mathematics from England. He started in the pipeline inspection service with British Gas in 1987 and has been involved in data interpretation and automation with MFL, transverse MFL and ultrasonic technology.

He provides special interpretation, troubleshooting and inspection support for many pipeline operators. It's all yours, Jon.

Jon Wharf: So, I'm going to briefly review ultrasonic tools in pipeline inspection. Frank did a good job in going through the general mechanics of the pipeline inspection and covered a lot of ground. I'll happily piggyback on some of what he said. And what that is from commonality and what it is from the ultrasonic impact as well. And point out where there is commonality and where there are differences between the ultrasonic and the magnetic's world.

So, my topics I hope to cover in this presentation are a brief description of the ultrasonic tools that are available and preparation in real terms that is required for an in-line ultrasonic inspection of the line. What steps are taken in analysis and interpretation of wall loss for measurement data which is one of the ultrasonic technologies. I don't think I can attempt all the ultrasonic technologies, but I will briefly refer to them. And then finishing up briefly with the strengths of ultrasonic inspection and the steps that you might take after ultrasonic inspections.

So, the different technologies that are available--there's two approaches here. You've got the liquid coupled approach, where you're using the product in the pipeline to actually inject the ultrasound from the tool into the pipe wall. The two main liquids that are a couple possibilities of direct wall thickness measurement, which is a metal loss volume type approach to pipeline inspection which GE is using the USWM tool.

And there is the crack detection option--which is attempting to find axial cracks. I will talk a bit more about that later. GE--that's USCD tool. And recently there is a combined detection which is both or all those cracks wall loss and crack.

So, that's using the product environment to take ultrasound from the pig into the pipe wall and back out again into the pig to measure. And then there is uncoupled technologies which historically was the elastic wave and the EMAT technology.

So, just going to the video. I've got a picture of the tool from a field mission and a little bit of the description of the technology process on each of these slides. So I have five slides with these technologies that I mentioned beforehand.

So, I've got the ultrascan wall measurement tool. So, again we've got the bodies of the pig here, we've got electronics, batteries, that sort of thing. Process is insertion here and back again with the tool the general duration is similar. And we have the sensors sitting at the back end of the tool in this case, same sort of setup, the general configuration is similar. Record a lot of data, you've got to run a line from one end of the pipeline to the other, safely, without damaging the pig and the pipeline. So, the mission here will be for this original metal loss. As in most technologies, once you actually get a pig into the line, start running it, you'll find out it's good at a lot of other things once you've built this pig you can help spread the missions a little further. And you'll see a bit more about the pipeline than you initially intended.

The basic technology here is relatively simple to understand. What we're looking at is like firing pulsed ultrasound through the pipe wall and then looking for two echoes. The first echo where the ultrasound meets the pipe wall, which is this one basically up here. And we're looking for the second echo, which has gone from the liquid into the pipe wall, hits the other side of the pipe wall, and comes back again. So it spends a little extra time going through the steel here, and that extra time is what gets you your coordinates of wall thickness at that one spot.

And then when you combine all these points, all these point measurements, it measures a hundred times per square meter, that then can build up a map of exactly what's going on in the pipeline. Here is a somewhat extended view where you're looking at one sensor tracking along a wall, and gives a value for the distance from the sensor to the wall.

And you're looking at the two values and building up a trace as you go along, as you go along the wall. How far the sensor is from the wall, how thick the wall is, and combining those two pieces of information and you can build up a very accurate map about what's going on in the pipeline. I'll probably spend a bit more time on some of the other ultrasonics on WM because it's more commonly understood technology. But all the various crack detection methods that ultrasound uses, the reason ultrasound is used for cracks is because it is a very hard thing to do in general and magnetics is not up to the type of cracks that a person has some SCCs with.

So here is the liquid coupled version of crack detection. You've got the pig here again, very similar layout, here's the mission that it's looking for SCC type cracking and weld cracking. And basically what's happened here is that the ultrasound is being fired through the liquid and into the wall to bounce along at an angle around the circumference of the pipe wall. So this is shown as a straight piece of plate, but actually it typically a curved circumference of the pipe. But for clarity it is shown as a straight piece of steel here. So as the ultrasound passes along the inside pipe wall it hits obstructions like cracks and other reflectors and bounces back to the sensor and collected to be analyzed.

And typically there's a very dense coverage of sensors. Some of them facing the and firing at clockwise and some of them facing and firing counter-clockwise, so you have a very densely filled basic data grid that covers the pipe wall for technical assessment of what reflectors the pipe wall is generating in order to detect and assess cracks.

Just a quick mention that there is a combined technology coming out of market as we speak, more or less that uses flexible ultrasonic radial of simple transducers to generate the digital sound and analog sound, both perpendicular sound and angled sound, in order to inspect both wall thickness and cracks.

The uncoupled non-liquid solution for crack detection previously was elastic wave using wheels, wheel probes, sensor probes so the probes sit inside of wheels and this tends to push the wheel into the wall and back again to the sensors and the sounds coupled through the edge of the wheel and inside the wall and back again bounces angled sound around and back between the sensors. A newer technology is the EMAT system by extremely clever magnetic wave arrangements actually manages to make the steel into the ultrasonic generator. Start with a high field when running a variation and due to the nature of the variations you can actually persuade the steel to stretch and change and generate ultrasound and using this process, again, the steel still responding to ultrasound and moving in that magnetic field to generate a corresponding signal back to the sensor in the transducer here. So this actually is more or less contact-less that lies on the top of the surface and there could be sound. So it doesn't rely on the pipe surface and you're actually producing sound directly in the steel.

So the preparation for an ultrasound tool run in general is a variable of three things. The line suitability which Frank mentioned that you're looking at the pipe track dimensions which depend on mission very much because if you are looking to run a long line then you're going to be looking to have an extra range, you're going to have batteries and going to have storage requirements. If you are looking to run a line that has tight bends, you need to have a different configuration of the pig as well. So just having one set of dimensions for a pig track, for any diameter, it's a kind of a negotiating matter exactly how much of the line you'll inspect and exactly what we'll do with it.

So, I mentioned bends, you also have to clear restrictions, and voids. You've got to consider all things within what wall thickness you're working in. So thin wall I would have said five years ago that it's a kind of a real limit on how thin you can go in ultrasonics. But some experts--we are chipping away at these limit standards. I think most thin wall pipelines are now very well within the boundaries of inspection for ultrasonic pigs. I would put the limits at 6 millimeters or about a quarter inch but we can see now go a little bit below that but ultrasonics can be used successfully to inspect thin wall even below 4 millimeters.

So, after thinking about the line and what you need and how to inspect that particular line, you have to think about the product, especially for liquid coupled ultrasonics. You need to have liquid phase, so the three phase issue is simply not available with ultrasonic as they stand right now. You need the liquid phase to work your ultrasound through with low particle count. You need to have good sound transmission characteristics and what we've talked about in that case is attenuation. We're looking at how much sound you're going to lose before it hits the pipe wall so its coming from the sensor to the pipe wall. You're losing sound all the time and will it get to the pipe wall and will it transmit into the pipe wall and will you hear anything back when it actually starts to come back towards your sensor.

And either of those can be achieved with a batch. Batching is such a big complex subject. I really don't have time to touch on batching. Within a liquid line perhaps it's a little simpler, but within a gas line it's very, very tough.

So the main thing that you need to really consider is line cleanliness. And, again, with the liquid coupled ultrasonics you do need very good cleanliness and with the elastic wave which has the wheel rolling over the surface you need a good surface to transmit ultrasound through. EMAT is so young I would imagine it has less stringent requirements but is again a very close to the wall technology so you need a good knowledge of the state of the line. So you need to reduce all these quantities in order to make sure you're getting a good ultrasonic inspection. And the upshot of this is you need to take a very stringent cleaning regime in order to get the pipeline ready for an ultrasonic inspection. In particular, we are looking at no soft wax or deposits, because any where you have soft wax or deposits you're going to lose the sound into that material. You can have a limited amount of smooth scale or hard wax but again the less the better.

So, having run our pipeline and gathered data, what we do next is when the pig hopefully arrives in one piece at the end of the pipeline. We need two phases of data quality assessment. Effectively we have one where we're looking at the immediate response in the field, we're seeing what the quantity of data collected is, what the general diagnostics of the speed of the pig during a run, that sort of thing. So there is a certain amount of immediate information that you can gather straight as you collect the pig from the trap.

And they do need another phase where you look in more detailed data and assess whether the quality of the data is what is required for a full inspection. You get a quick answer which might be no, it's no good or its limited in some way and you'll get a slower answer which is these area of data are satisfactory for reporting on.

So after we've looked at that we can go on to data interpretation which is the main review of the data to generate a report. And part of that is the referencing that Frank was saying about. We need to be able to tell you where to dig, not just what's in the line but also where it is. The inspection reporting is again common to the magnetics. I just thought I'd show you a few pictures in detail on the wall thickness measurement mission just to show you how the mission spreads a little and show you a little bit of data because I like looking at data and I assume other people do too.

Metal loss is the main mission for the wall thickness measurement. The direct ultrasonic system picking up general corrosion, as you see there, the grooving and axial corrosion. The only limitation here on the size of defect is that they have to be big enough for the sensor to bounce sound off of the kind of limited width of the ultrasonic beam so it has to be enough return from that for the ultrasonic beam to trigger the electronics. And then the other kind of incidental mission requirements that we get from wall thickness measurement, mid-wall defects, lamination, too. I don't think there's another technology that you can use seriously to detect laminations and of course dents just due to the nature of the passage of the sensors over the dent inside the pipeline. You see a variation here. So here is a couple pieces of data. You've got some pitting. What we're looking at here is the circumference of the pipe unwrapped this way.

And then the other kind of incidental work--mission--requires that you get a record. Just due to the nature of the passage of the sensors. We've got a couple pieces of data. What we're looking at here is the circumference of the pipeline out this way and the axis of the pipe along left to right here. You can see that you got a black background which is the nominal wall or the commonest wall in that area, and back to going to hot colors as you go to metal loss. And along this arrowed line on through the middle of that C scanned type area you've got a profile along here. I don't know if you can see it but that's the precise measured profile through that corrosion that's been picked up and can be used for further interpretation.

An area of general corrosion and a large area that can not be quite big enough to be challenging for metal loss at the magnetics but eventually as you get to very large area of metal loss, magnetics will start to struggle to see the variation where as you're getting direct measurement all through that metal loss from the ultrasonics. So for corrosion or general loss type situations you're going to find very good information from the ultrasonic system.

There's a lamination, very flat, and sitting precisely at 50%. So to distinguish my bloody analyst but not necessarily majorly obvious I can assure you that's a lamination and a slightly more complicated picture. Here we're looking at the amount of standoff of the sensor from the wall shows a very strong dent. So once again that's one of those incidental missions that gives us quite a lot of information about the dent, unfortunately not quite enough to say how deep it is. Here's some feed back from the field. A piece of ultrasound signal compared to a rubbing an example of the correspondence you will get between ultrasound data and the field excavation results. And that exact profile I'll expect to be well used in making a pressure sensing assessment rather than using any of the assumptions of how deep and long a defect is. You'll be able to use the exact profile and come to a conclusion on the severity of any given defect.

So quickly, through the strength of ultrasonics, we've got the historic profile, we've got a wide wall thickness capability and it's very good at thick wall because it's a measurement so you're not losing any percentage accuracy. You're still looking to millimeters rather than percentage bands suitable for wall loss and you haven't got that entrance step as strongly that you have with magnetics. So instead of looking at the magnetic signal and varying it at depth, you're looking at a measurement. So you do have a lot of power in there with your pipeline preparation.

Crack detection in ultrasonics is tough mission and that's why so many varieties of ultrasonic responses to that mission.

Follow up in field. I guess the most important is deep location confidence and then we got the expectation with WM. You've got most of your analysis can be done in office. Only ambiguous features really you need to find out in the field. You'll know what they are from the report.

And to make a note, one of the things you can follow up an ultrasound inspection with is to re-inspect at some later date and examine how your corrosion has changed at the time because of that point by point exact profiling of your corrosion.

So, quickly through the technical components--we've got the historic profile, got a wide wall thickness capability, some measurements so you're not looking at any unknowns.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: Okay. Thank you, Jon. I didn't expect an applause for that, but that's okay. Okay. We now have 10 minutes for questions from the panel, and once again if you would identify yourself by name and organization before you ask the question, that would be great. Anybody have a question? Please.

Greg Swank, BP: Two questions, Jon. First, how accurate is the UT tools in detecting dents, and in particular dents with any metal loss? And then the second question on your EMAT pig. Could you relate some experience with that EMAT tool, particularly around its accuracy and the type of anomaly detection?

Jon Wharf: So accuracy on dents, the capability on that I guess for the WM. The dents that are picked up by the WM are typically very small, lower limit of anything that can be picked up. And the variation that we're looking at is a standoff from what the sensors from pipe wall is down in to less than a millimeter. So, we can see that it's generally with the ultrasonic system it is smaller than you would expect to detect with the caliper. Which does lead to some unease in pipeline operating communities because these dents are really not threatening. And this is an idea that you would rather not know about because they are not that serious. So, yes data for detecting very small or very large. We have a lot of history in finding dents that are very fine. As for metal loss in dents it is fine as long as you're looking at very smooth dents. If you start getting into quite sharp dents, and my estimation of sharp is something that changes about 1 in 3, so if you move say, an inch along the pipe and the wall position has changed relative to the sensor by about a third of an inch than you are starting to lose things. You would start to get some loss of echo because of the angle of the wall. So in the sharper dents we will struggle to see some metal loss within the dents but anything that is smoother than that we will see all of the metal loss exactly as we would see in undented pipe.

On the EMAT, I know that we've undertaken a number of runs with EMAT, but I couldn't swear I'll tell you all the experience. What I can tell you is that we've undertaken EMAT and also undertaken EmatScan CD, the liquid-coupled technology. When we run a pipeline with this technology and have identified cracking using this process and then also have run it with EMAT and have identified the same cracks that we have found on a blank analysis. We have had the benefit to promote both kinds of these technologies and have identified the cracks with both of them. It is a longer range system and it does require more correlation of data to make a final judgment on the feature of the pipeline but we have had some good results.

M: Does that answer your question? That was very good. You continued your presentation in your answer. That's good. I haven't seen that before. Other questions?

Bill Flanders, OPS: How well does your ultrasonic pig determine preferential probing in these girth welds?

Jon Wharf: Corrosion in a girth weld is basically detected to the same specification as any other metal loss type corrosion. The deduction of some kind of preferential mechanism has basically been a matter of observing that you see metal loss. But as far as the actual detection is concerned it will be detected just as well as any other area

M: Does that answer your question? Other questions, please.

Chris Dash, ConocoPhillips: What's your typical turnaround time to get results?

Jon Wharf: Our contract length and response I guess varies from operator to operator. We target 60 days. But for short pipelines, I guess--there's not a lot of short pipelines in Alaska, there's not--it would be quicker. The other thing we can sometimes do is as part of the data quality assessment for any kind of real seriousness that needs to be acted upon quickly, is by excavating or by measurements.

M: Does that answer your question? Other questions from the panel? Yes, please.

Bill Flanders: If you had waxing in internal corrosion, would that interfere with your ability to determine the depth of pitting?

Jon Wharf: It can. Especially with soft wax. It will tend to soak up sound. It is one of these very difficult pigging requirements, that we've seen some people overcome. We've seen on occasion that people are able to overcome the kind of embedded deposits or soft wax in deep pitting. Sometimes people are able to overcome it. But I've seen them with a really significant effort. If that is an issue with that particular pipeline, I think it can be overcome.

M: Does that answer your question? Other questions? Please.

Tom Maunder, Oil and Gas Commission: You mentioned that the ultrasonics, unless you have properly figured out problems in systems that have gas 3-phase, is the liquid sensor sensitive to changes in the composition you have effectively of oil and water?

Jon Wharf: I would say it is. I would say that if you have got a mixture of liquids than your introducing some uncertainty into it. However, if you have got a fairly consistent mix of liquids then I would expect that to be something that we could pave for to some extent. However, I wouldn't say that I would have as much confidence in a mixed-liquids type over runs in a single-phase type. Although, the speed of sound in steel constant is not altered. Although you may get some anomalous effects in looking at how far the sensor is from the wall you should still get some good response on accepting the readings from the steel.

M: Does that answer your question? We have time for one more quick question and quick answer. Thank you very much. We appreciate it.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

M: We've gone through the first presentation and questions to the presenter, and now we're going to start in on our next round of questions to the second presenter, and that's Jon Wharf. And Jon in his presentation was talking about ultrasonic technology UT. And I have a few questions for you as well, Jon.

What is the accuracy difference between internal UT pigging and external UT measurements?

Jon Wharf: Right. The external UT measurements which is in the ditch type collection, what we're talking about is a very slow painstaking process where a lot of time and a lot of feedback from your equipment on exactly where to look for your most metal loss or your worst point of corrosion in an area of corrosion. So you've got a variety of probes, you've got a lot of time and you've got equipment at your disposal when you make an external UT examination of a pig--of a pipe surface. When you're running an ultrasonic tool through a pipeline you're doing it at something like walking pace. You're collecting one shot data so you've got the luxury of absolutely only one look at the pipe as you go through, so the circumstances of the data collection are quite different and you try to inspect 10s of hundreds of kilometers at a time with the tool. I would say this about the accuracy of the data is that you're looking like something like .1, .2 millimeters so about the accuracy--precision, sorry, of the--on the depth. Is one of the key points. And then you get to the context of the depth measurements all around it. So you've got a quite a good understanding of an area of corrosion. But I'm sure you can get more accurate values if you've got the time to take an hour or so to get that area of corrosion with correct external sources. I would expect that accuracy to be considerable higher.

M: Okay. Anybody have any comments they would like to add?

Bill Flanders: I would just like to make a comment that what he says is very accurate. They have the ability to do a good quality measurement. What we've seen in practice is not necessarily in Alaska but on other operated lines is they don't have the features--they don't have equipment that is calibrated sufficiently accurately enough to really correlate well with the pig data. The field measurements are not as accurate because they are not written procedures, not qualified people performing those procedures, accurate equipment being utilized to come up with accurate measurements to qualify the pig data. So if you want to use this as a valid data end tool, you need to have a set of standards for the field operations just like the pig has a set of standards for its operation.

M: Other comments?

Chris Dash: Many operators do have field procedures.

M: Now we're getting there.

Jon Wharf: Just one follow-up. The other thing about the volume of data that you generate during the pig run is that you have an awful lot of kind of context, if you like, to understand if there's any other issues in the data collection field and you're not looking at one area of the pipeline, you're looking at the whole pipeline. So you get a lot of chances to spot any calibration errors or if there is any other issues going on, there is a very strong chance of spotting it when you've got thousands of square meters of data collected.

M: Okay. Yes, please.

Bill Flanders: Just another comment. This is a perfect example. When you are in there and you are looking at it you can find other defects that maybe the tool wasn't designed to identify. Once you've established that this is a threat to your pipeline system, then you need to account for that. That's why you need good procedures for documenting all the defects that you find on your pipe so it can go back to an analysis person that can recognize that and say, "Yes, we're finding narrow axial corrosion. We're finding something that's unusual and that this tool may not be the best tool for that process."

Chris Dash: So you're saying feedback's the key for that operator to the vendor?

Bill Flanders: Absolutely.

M: Now you know why we sat you guys next to each other. Other comments? Okay. Second question. Is UT sensor lift off a problem at girth welds? You might want to explain what a girth weld is in case people are not familiar.

Jon Wharf: The girth weld is where two pipe pieces are welded together to form a tube to form a kind of a regular punctuation mark on the pipeline. I like to think of it as a kind of a localized ridge for locating things on a pipeline. The most valuable thing you can have when you pig the pipeline and the pipeline inspection company has told you to dig. So, over the girth weld there is usually a small internal bead of that girth weld that will let the sensor lift off very temporarily and locally over that girth weld. And that's something that every inspection technology copes with in one way or another, so if you have magnetics or ultrasonics or what have you, they'll all register this slight disturbance and the sensors will have to ride over it from there on.

What I'll say about the ultrasonic systems that I'm familiar with is they generally behave pretty well, they have a chance of a very localized metal loss actually within the weld beam, adjacent to the weld beam and anywhere in the parent steel I expect it won't mean anything to the ultrasonics. It will just lift off the piece of steel and you'll have a very good look at the small area within the weld bead and you'll get that with ultrasonic systems.

M: Okay. There's actually a second part to this question that was related to the first. What is the probability of missing corrosion in the heat affected zone of the girth weld, especially if the weld has excessive reinforcement?

Jon Wharf: For ultrasonic systems, it will--the heat affected zone is not part of the weld bead so it will be inspected as the normal pipe. If you have a very thick or irregular weld, then you could expect to lose some data actually in the weld bead. So there will be some chance in the weld bead but adjacent to it in the heat affected zone I would expect to have no effect on the inspection.

M: Okay. Does anybody have any comments on the answer? Okay. Next question. Can or should a UT be run at the same time as MFL?

Jon Wharf: Well, one can? Yes, it certainly can be, and it has been the case that we have had UT and MFL pigs in the line at the same time. It's more a pipeline operation question pretty much because it's running multiple pigs in the line is a tough schedule. You sure you've got to watch the passage of multiple pigs if you're running a batch. And then you might have--you might have two batching pigs, a cleaning pig and a UT pig and an MFL pig and a couple more batching pigs behind that. They started to look like a traffic jam out there, so it would be a project management issue I guess you might say or something like an operational issue. Something like that. But it's very feasible with the right preparation.

Should they be run in the line at the same time? Well, it may well be that the circumstances require it, that you're trying to get magnetic and ultrasonic information from the line because of your known defect risks that are of such a spread that the best technology to cover all instances do impact both of the technologies then I can see that they might occasionally be required. I think it would be quite unusual for that to be the case, but if it is required then it's sensible to do because you're trying to batch the flow through the pipeline and you only want to run product through it one time then it would be very much a study of why you want to do it as well as the benefits you're getting from it and the risks that you're taking in doing that.

M: Please.

Mark Olson: Jon, wouldn't you want to use the MFL tool as a cleaning tool for your ultrasonics?

Jon Wharf: It would certainly do a very good job.

M: And maybe some Molson. Okay. Any other comments?

Pat Vieth: I have one question for Jon. How many times are you aware of where they have batched both an MFL and UT pig at one and the same time?

Jon Wharf: About two or three. Not very often.

M: Any comments from the panel? Next question. Can you tell the operator if soft wax or other debris has prevented your--and these are acronyms--USWM or USCD tools from gathering enough data to be deemed successful at the field level? I'm not sure everybody knows what USWM and USCD stand for.

Jon Wharf: Yeah. USWM is the direct wall thickness measurement on an ultrasonic tool. USCD is the angled beam crack detection on an ultrasonic tool. If we have some wax buildup that has locally reduced the ability of the pig to inspect the line, I would expect us to see that as an area of particular loss. That is to say data loss, generally speaking. Given that the ultrasonic tool is looking for that particular loss, if it's extensive then it may be that we can establish that loss in the field. There are diagnostics available when the pig's received to say how much data loss have we observed. If it's very localized it might not be detected until the analysis phase of the assessment. But it would certainly be picked up and if it was of a limited degree or there is no expectation of improvement for the subsequent run and the data is analyzed through to a final report before attempting a rerun, then that should be fully annotated and noted in the report as an area of an incomplete inspection. Obviously that risk would have to be factored into any plan.

M: Any comments from the panel? Yes, please.

Greg Swank: Is there any techniques you could utilize to increase the gain on locations that have a reduced signal return?

Jon Wharf: Not really. The gain is generally set with a product that's running in the line. That's why we look to have a gain that's pretty well--sorry, a product that's pretty well uniform. The gain spread tolerated is quite large but the tendency of soft wax is to dissipate the signal so it is not entirely a gain issue, it's more of an echo dispersion issue. I'd rather not go into that.

M: Other questions or comments from the panel? Okay. Second part of this question latest question. Do you provide recommendations on how clean the pipeline is based on envelope returns or pig trap accumulations?

Jon Wharf: Yes, we have some raw guidelines on how much debris or wax is collected by the pig face, and that's quite useful for the shorter lines. As you operate in a longer line then it starts to become a little bit of an issue because as you've got a cleaning pig that runs through 200 kilometers, say, of pipeline then it's difficult to say whether it's an issue at kilometer 40 because by the time it reaches the trap it's got a chance to clean itself off and it may not be so apparent by the time you get to the end of the line that there was a debris issue at that point in line. So generally speaking we have some practical guidelines but there will be occasions when they are difficult to follow and they don't always tell you everything you need to know about that.

M: Any comments on that? Yes, sir.

Jon Wharf: I mean there is a kind of a standard ratio to follow. And it works almost all the time.

M: Okay. Next question. During an ultrasonic inspection, can the data loss due to wax buildup be processed to compensate for the change in sonic speed or is the data lost?

Jon Wharf: Data loss is data loss, unfortunately. So once the pig's gone through that's all--all we've got is what was recorded on that run of data. I should also say that because you are recording on each lot you are recording two batches. You are recording distance of the sensor from the wall and the amount of metal in the pipe wall. You can sometimes suffer the loss of that second value, the thickness of the pipe wall and still gather some information about the extent of corrosion.

M: Okay. Any other comments on that answer? Okay. How do you assure "clean pipe" for UT purposes? Any specific criteria that can be put in a contract with an oil company?

Jon Wharf: I guess this is again the question about the practical way of assessing the cleanliness of the line, and the same comment applies. There is some feedback from the run of the cleaning pig and there is a minimum cleaning regime that is expected to be necessary for that particular cut of product. You will see some products are more prone to produce debris or other challenging environments in the line than others. And heavy crude is something that might be an example of something that would be very tough to live with. And Jet Fuel, might be perhaps something that very rarely produces any wax buildup.

M: Any other comments from the panel? Okay. You mentioned suspended solids and PL cleaning--pipeline cleaning criteria. What size and amount would affect results on level needed to be considered "clean."

Jon Wharf: Again, without having guidelines in front of me, there is a certain amount of suspended solids that we can tolerate. It's just a matter of the sound attenuation and that the solids are not attenuating the ultrasound that is being fired to the pipe wall by a significant amount or are within range, I should say, then we will tolerate it or otherwise we'll start losing density. There are some guidelines and there would be assistance available to anybody who is considering that kind of contract and the guys on the operations side of things have got a lot of detail on that sort of question.

M: Okay. Any comments from the panel? Okay. Once again I know you are going to be disappointed. This is the last question. All right. Now this question was actually asked of Frank as well, so at the end of your answer then we will ask the audience who did a better job. Not really. Okay. If you came to a pipeline with no recorded history of problems, what pig type would you use first to inspect it?

Jon Wharf: Well, I think Frank answered this question very well, actually. So I would probably say the same. We would start our investigation by trying to establish some kind of knowledge of the pipeline in terms of its geometry and then depending on exactly what kind of line it was again. As I have said, if you've got something that's running clean, you might, once you've proven the line and determined the geometry, you might want to go onto an ultrasonic type of inspection. You probably would want to consider something about the age of the line, the coating types, and the country that it goes through. Is it going through hills or swamps or whatever, you know. There is this information about every pipeline. Not always directly about the pipe itself but about where it is and when it was built, what it was built for and any leaks it's had. So, every pipeline has some kind of history so there will be starting points for making that kind of decision. It could be that you want to go to ultrasonic or you might want to go to MFL. As I say, the top inspection tool, and it might well be a good idea to go through that project, beginning with an ultrasonic inspection.

M: Okay. All right. Any other comments? Okay.

Ultrasonic tools in pipeline inspection

A review of the technology

Jon Wharf

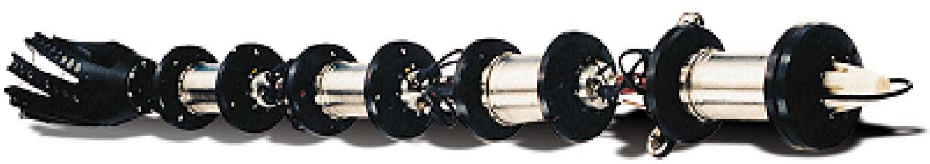
Topics

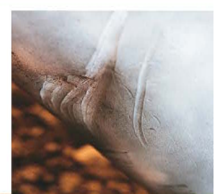
- Brief description of ultrasonic tools
- Preparation for an in-line ultrasonic inspection
- Analysis and interpretation of USWM data
- Strengths of ultrasonic inspection
- Acting on an ultrasonic inspection report

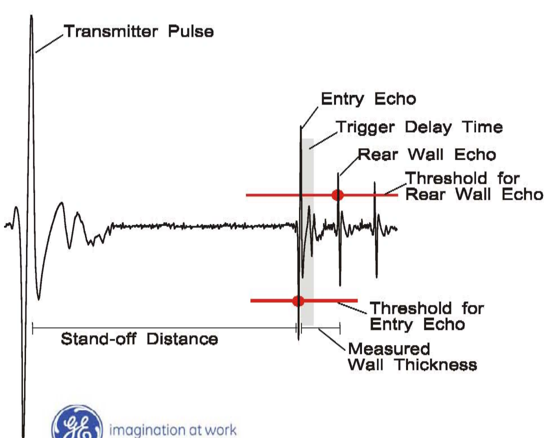
Ultrasonic technology inspection choices

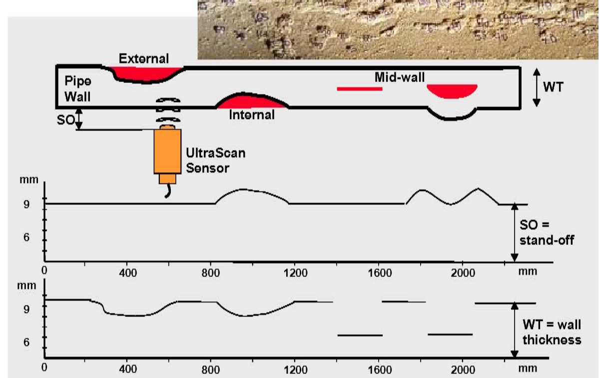
- Liquid coupled – requires liquid in pipeline
  - Direct WT (metal loss) measurement (USWM™)
  - Crack detection (USCD™)
  - Combined (wall loss and crack) detection (UltraScan™ Duo)
- Uncoupled – with gas or liquid
  - Crack detection (EMATScan™ or Elastic Wave)

UltraScan™ Wall Mesurement – USWM

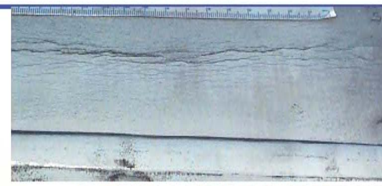


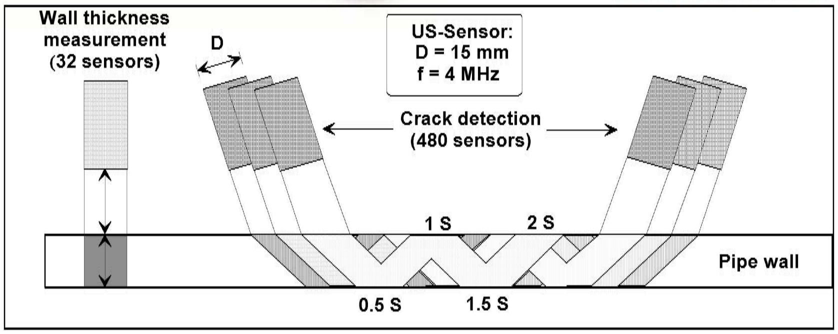




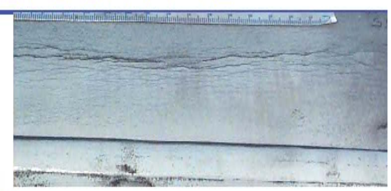


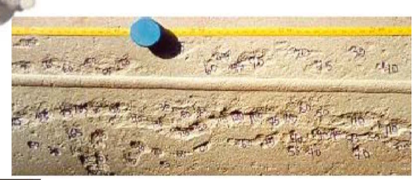
UltraScan™ Crack Detection – USCD

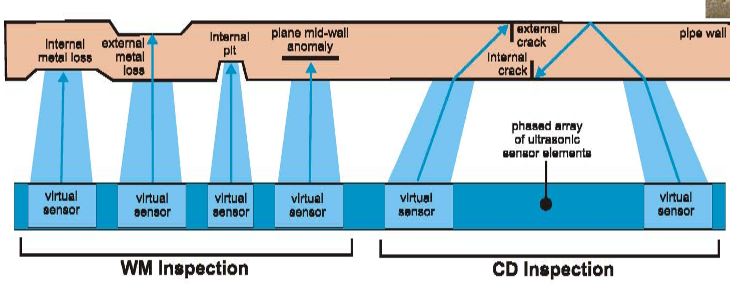




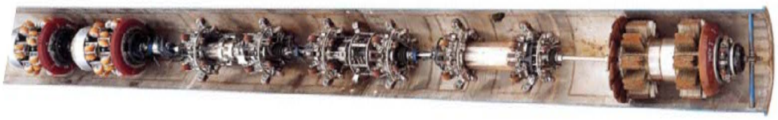
UltraScan™ Duo – combined crack /ML

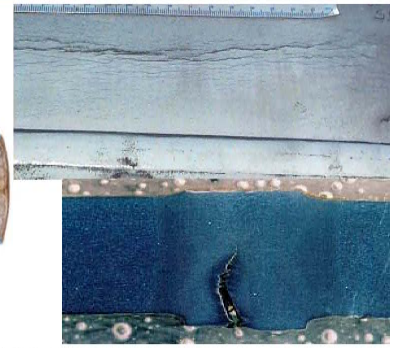


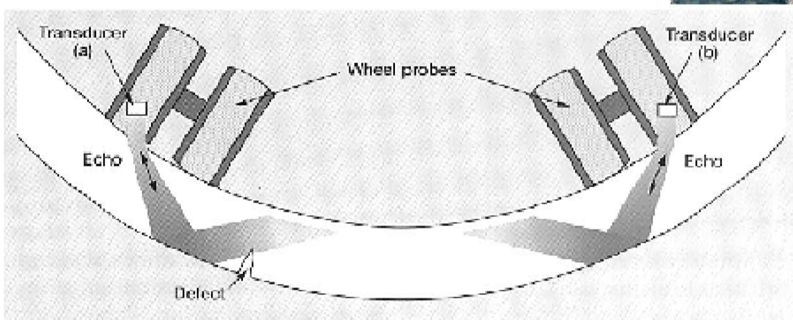




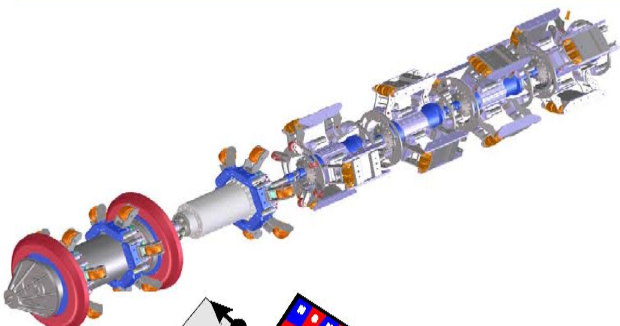
Elastic Wave

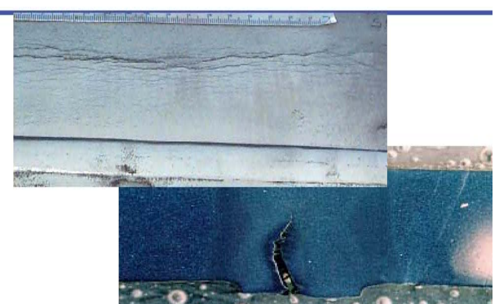


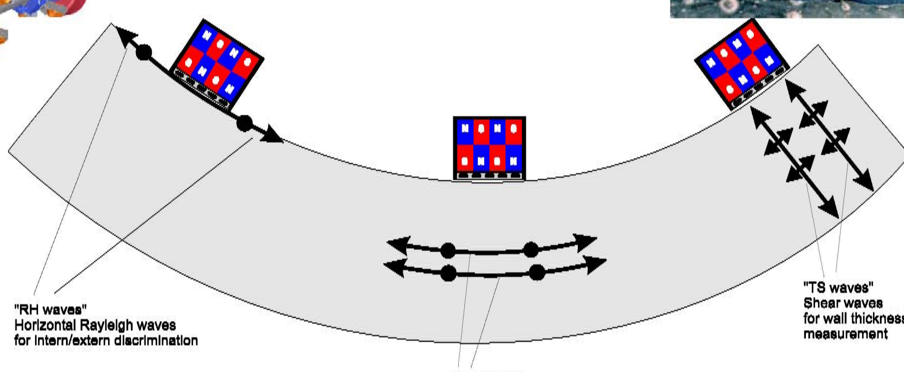




EmatScan® CD







Preparation for ultrasonic tool runs

- Line suitability (common across most tools)
  - Trap dimensions (dependent on mission)
  - Bends (1.5D, 3D, 5D)
  - Restrictions (fittings, dents, ovality, multi-diameter)
  - Voids (at valves, offtakes)
  - Wall thickness (thin wall can be a challenge for ultrasonics)
- Product suitability
  - Liquid phase only, low particle count
  - Good sound transmission characteristics
  - Batching options to achieve the above:
    - *But batching is a complete presentation in itself*

Preparation for ultrasonic tool runs

- Line cleanliness (*vital* for liquid ultrasonics)
  - Suspended particles
  - Wax (hard or soft)
  - Scale (smooth covering)
  - Deposits (irregular or pit-filling)
- Multiple cleaning runs often required to reach inspection conditions
  - NO soft wax or deposits remaining
  - Very limited *and smooth* scale or hard wax

Ultrasonic inspection - analysis

- Data Quality Assessment
  - In-field completeness / diagnostics
  - Analysis centre full assessment
- Data interpretation
  - May include high-level pass for urgent features
- Referencing
  - AGMs, fittings, weld numbering
  - Correlation to other technologies
- Inspection reporting
  - Report, listings, data viewer

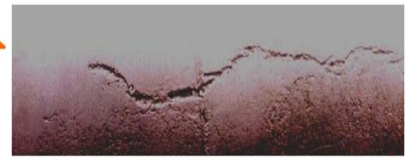
UltraScan™ Wall Measurement

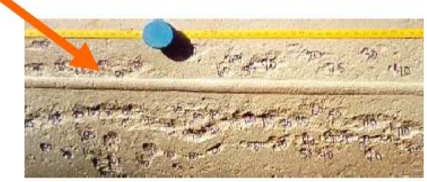
Direct ultrasonic time-of-flight measurement of remaining wall thickness

USWM mission - Defects in Pipelines

Metal Loss

- General Corrosion
- Channeling / Grooving Corrosion
- Narrow Axial External Corrosion (NAEC)
- Pitting Corrosion
- Gouging
- Manufacturing-related wall thickness variations

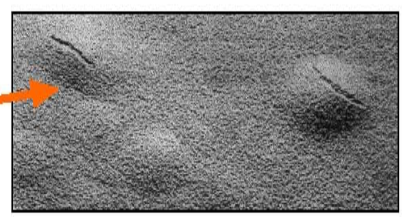




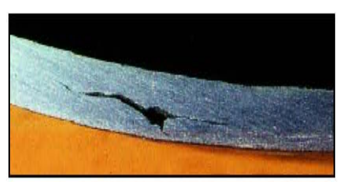
USWM mission - Defects in Pipelines

Mid-wall Defects

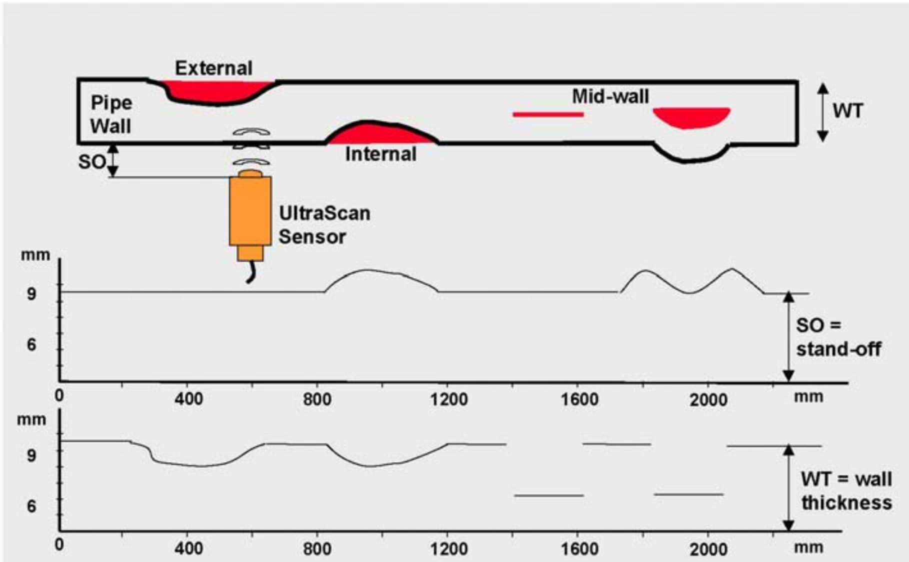
- **Laminations**
- **Bulging Laminations**
- **Hydrogen Induced Cracking (HIC)**
- **Inclusions**



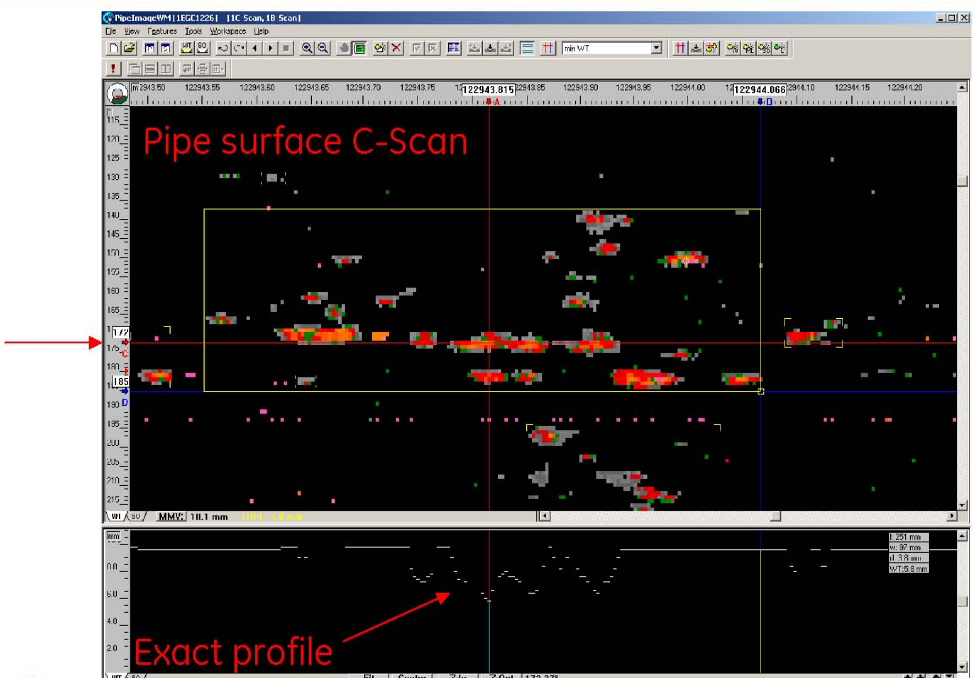
Dents



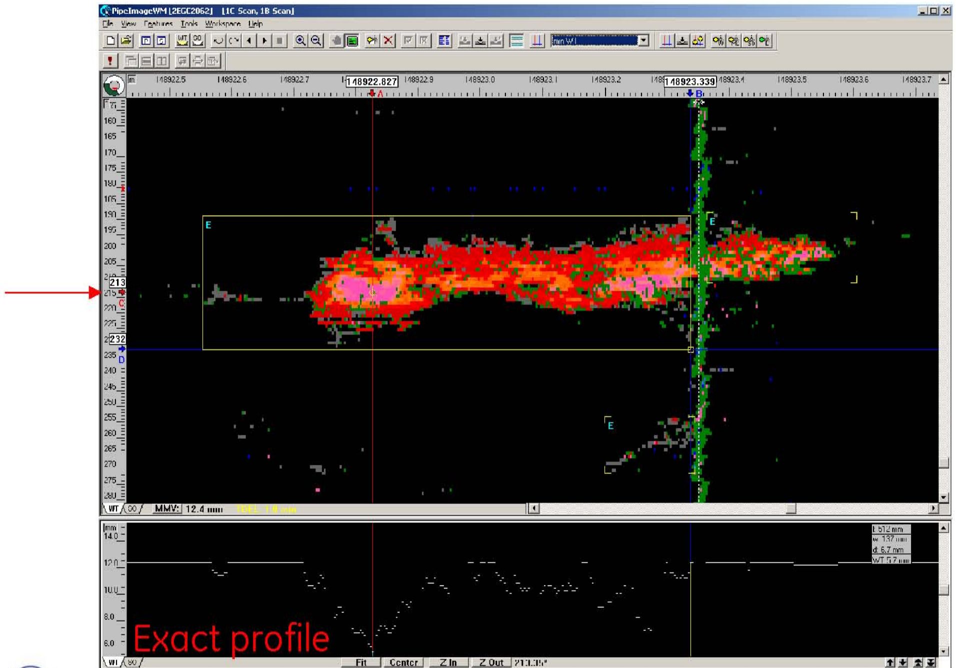
Measurement principle



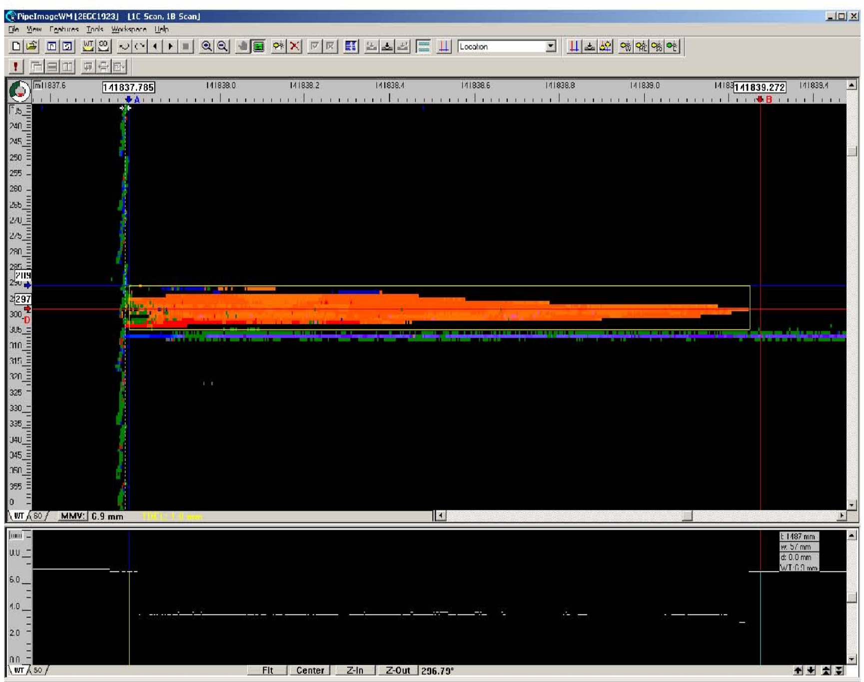
Sample data – pitting



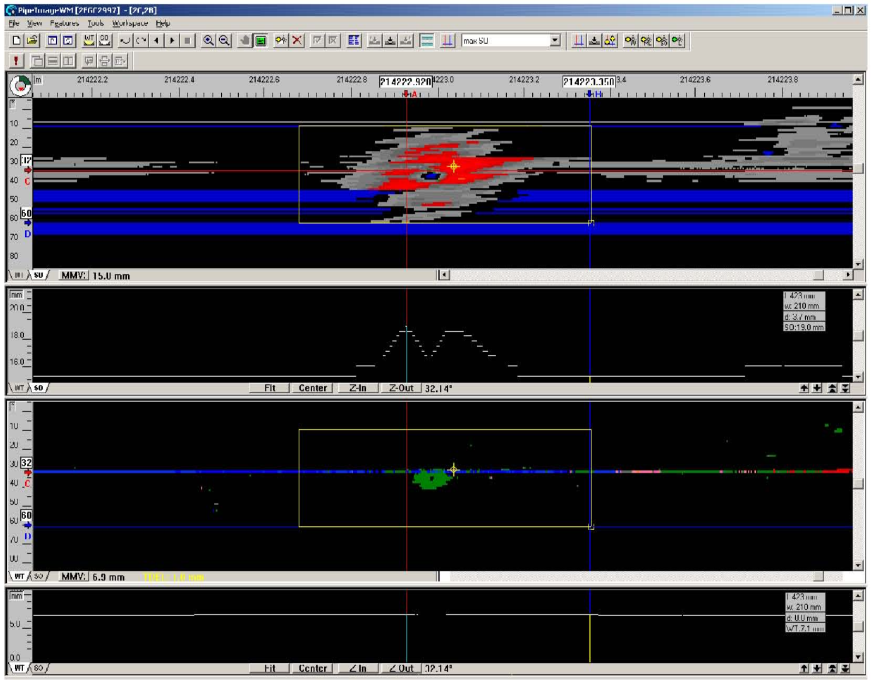
Sample data – general corrosion



Sample data - lamination

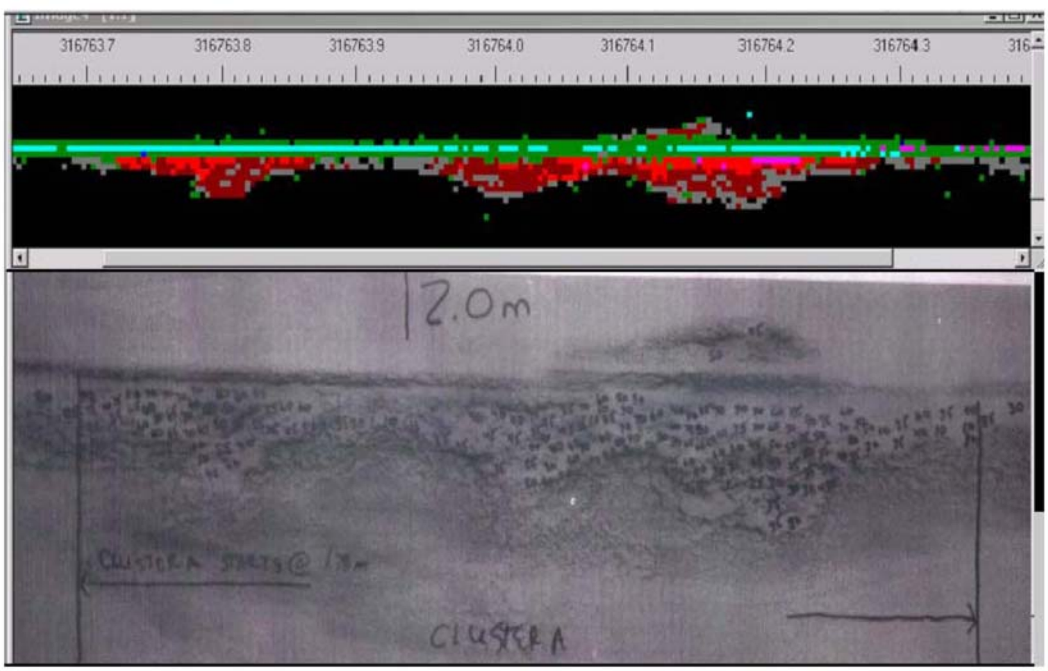


Sample data - dents



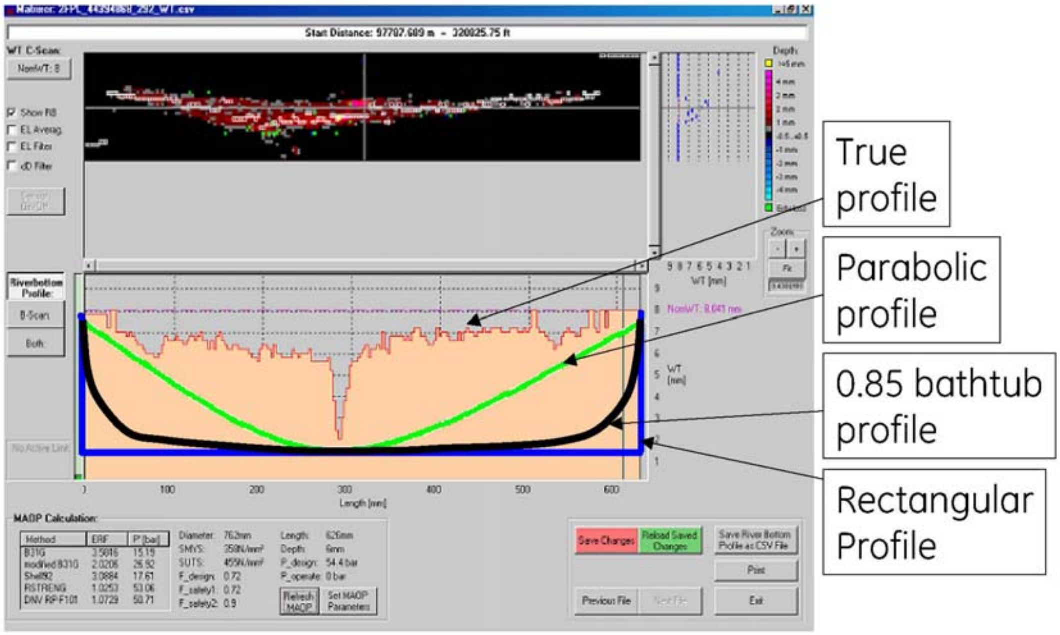
imagination at work

Field correspondence



imagination at work

Pressure assessment



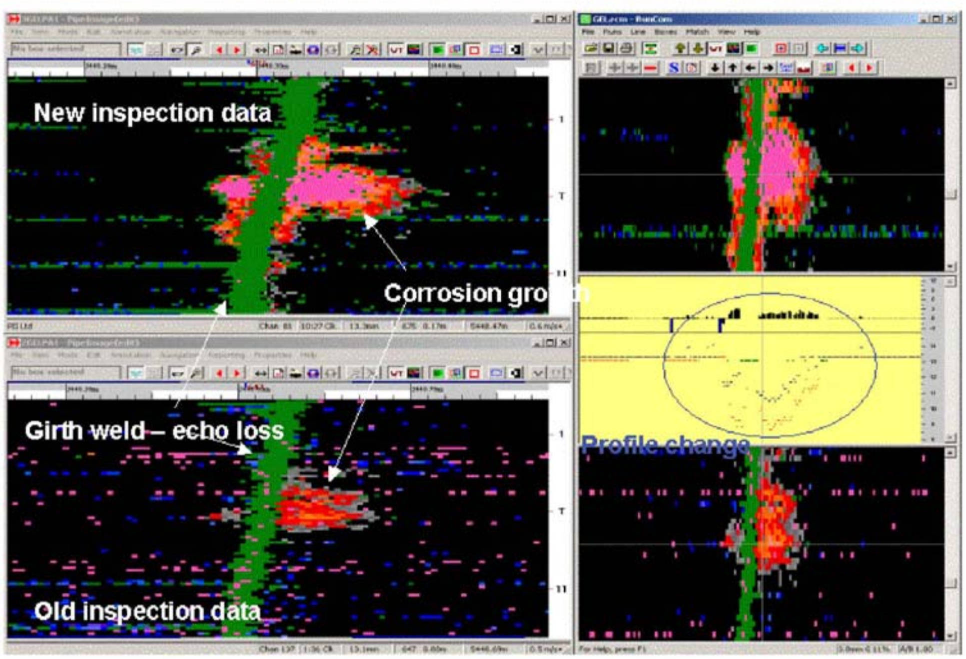
Ultrasonic inspection - strengths

- For USWM
  - Direct profile of metal loss
  - Wide wall-thickness range, very good in thick wall
  - Suitable for channelling and large area wall loss (eg. erosion)
  - Reduced analysis inference (direct measures from tool)
  - Sentencing by profile analysis
- For crack detection
  - Non-volume defects – a tough mission
  - Direct detection of SCC issues (compare DA)
  - Comprehensive crack assessment including in welds

Ultrasonic inspection – follow-up in-field

- Dig location confidence
- For USWM
  - Metal loss and laminations fully characterized
  - Tight tolerance on depth and profile
  - Ambiguous features if any highlighted in report
  - Most analysis can be in-office; dig for repairs only
- For crack detection
  - Dig program recommended for feedback
  - Variations in product composition may require characterization
  - Combine with results to assess crack criticality and maintenance programs

Ultrasonic inspection – follow-up inspection



Ultrasonic tools in pipeline inspection

Any questions?

APPENDIX H

INTELLIGENT PIGGING CONFERENCE PRESENTATION 3

GEOMETRY AND DEFORMATION/CALIPER TOOLS

PAT VIETH OF CC TECHNOLOGIES, INC.

ABSTRACT OF PRESENTATION 3

Geometry and Deformation/Caliper Tools

Speaker Name:	Patrick H. Vieth, Senior Vice President – Integrity and Materials
Company Name:	CC Technologies, Inc. (*a DNV Company*)
Website URL:	**www.cctechnologies.com**
Type of Business:	CC Technologies is an engineering and research firm specializing in corrosion, materials and integrity.

Pat Vieth will provide a brief description of Geometry and Deformation/Caliper Tools. Topics of discussion will include:

- Potential integrity threat for deformations;
- Geometry tool design and function;
- Deformation/caliper tool design and function;
- Other In-Line Inspection (ILI) tool capabilities for detecting deformations.

TRANSCRIPT OF PRESENTATION 3

M: Our next presenter is Pat Vieth. Pat is the only thing standing between us and a break.

Pat Vieth: The pressure is on.

M: No pressure. OK. Pat is with CC Technologies, and he is here to talk about geometry, deformation, and caliper tools, and other smart pigs. Pat is a Senior Vice President of integrity and materials and a mechanical engineer. He has 18 years of experience in the field of pressure vessel fracture behavior, and defect assessment methods for transmission pipeline systems. Pat's expertise is primarily directed towards assisting pipeline operators with the development and implementation of short term and long term pipeline integrity management programs. Pat's presentation will be about 20 minutes in length followed by 10 minutes of questions. Pat, thank you.

Pat Vieth: Thank you very much. The one thing that you did fail to mention is I went to Ohio State University, and there is a football game this Saturday that we are looking forward to. Secondly, I'm honored to be here with a great group of subject matter experts. Those from both the regulatory side, inspection vendors, operators, and engineering and field service providers.

The reason that I mention that is that in the application of all of these technologies, it takes this whole group of people to be able to best utilize all the information that is produced through these inspections. Also to put it into perspective, and this follows along with a lot of what we have discussed today, is how we have evolved over the last 10 to 20 years. If you think about where we were in 1985 with these technologies, and the ability to acquire and analyze the data, we were lucky if we had a computer with a 20 megabyte hard drive, and now we are all carrying around two gigabyte sticks in our pockets. So, we have certainly come a long way both in the way of gathering the information and analyzing it. And lastly, we are in a continuous learning curve. Taking all the information that we have, the experiences we have, and focus the industry to address these integrity threats; it is certainly a great group of people working on this exercise.

In terms of the presentation that I have today, first of all, taking a look at the potential integrity threats that are being addressed through the use of deformation and caliper tools. The integrity threats that we're focused on include but are not limited to: mechanical damage, dents and buckles; also taking into account how we respond to these--there's a number of contributing factors in terms of the severity of these threats; whether it's in a natural gas pipeline, hazardous liquid pipeline; whether it's operating at relatively high pressure or low pressure; whether or not there's any subsidence activities that need to be considered with; the effects of temperature--whether or not we have any expansion or contraction of the piping system.

Secondly, the tool design, specifically how the tools are, how they've evolved over time, what some of the capabilities and limitations of those technologies are; and then the application of the results that we have from performing the survey.

Turning to the integrity threat themselves. We're taking a look at different types of geometries or geometric changes we find in the pipeline. One of the significant areas is constrained versus unconstrained dents. That is particularly a concern whether it's in--if it's in a liquid pipeline. Most typically a constrained dent is what we would call a bottom side dent. That is, the pipe is sitting on some object, generally a rock. An unconstrained dent is more typically found on the top side of the pipe. It could be a pipe manufacturing defect. It could be mechanical damage or it could also be a rock.

Taking a look at dents with metal loss or cracking, that when we have any stress risers that could exist in a dent we have a propensity for fatigue to initiate and propagate and produce a through-wall crack.

Metal loss in cracking is not always a cause for measurable dent. I'll show some examples of this later on. Buckling due to pipe displacement or subsidence. And last, wrinkle bends from pipe construction. In early days there were a lot of field bends and wrinkle bends that were introduced into pipelines. And it's part of our job to assess and manage those appropriately.

The top picture here we have what I would consider to be an unconstrained dent. It happens to be on the top of the pipe. It was likely caused by some type of mechanical damage. You can see here that the coating has been removed in this area. So, in addition to taking a look at the integrity threats that we have in dents, we can also have coincidental damage--whether it's external metal loss. We could have the possibility of stress corrosion cracking, especially near neutral pH stress corrosion cracking to initiate.

Here we have a constrained dent. This dent was identified through a geometry tool. You can see here that it is sitting on a rock. And over here on the right we have a wrinkle that has occurred.

Certainly, mechanical damage is one of the threats that we are most interested in. If you take a look at the report--one set of data, there are a number of reportable incidences for mechanical damage and releases that have occurred at the time of hitting a line. We, unfortunately, had one I saw in the news in the past few days which is in immediate release.

What we're taking a look at is latent defects--defects that--mechanical damage that could have occurred some time back, how they are interacting with the environment, how the effects of pressure cycle may be taking the cracks that can occur in this mechanical damage can grow to failure over time.

You can see here, this is a typical backhoe hit on a pipeline. You can see the two teeth from the backhoe going around the pipe circumference. In this photograph in the upper right you can see the cracks that have initiated due to the cold working that occurred when it struck the pipeline.

You can see here that there's also a measurable dent in this location. The dent combined with the metal loss--we did specifically address it in prior discussions, but the capabilities of tools today in today's markets to be able to detect and accurately characterize existing mechanical damage and pipelines is not 100 percent.

It's also important to recognize that just because we have mechanical damage it may not necessarily be associated with the deformation. Here are two examples where we have an axially oriented gouge that occurred due to a backhoe strike. Here is another area of mechanical damage and also it's important to note that when a caliper tool or deformation tool was run through this line, these locations were not detected.

One interesting point about this particular third-party damage is that it occurred when a fellow was putting in a concrete slab to put on his trailer. He hit the pipeline and instead of reporting it he moved the pipeline markers and still put the slab right over the pipeline, so when this was excavated the trailer had to be moved.

One of the first applications for finding geometric changes in pipelines is to take a look to whether or not other tools can pass through the pipeline--other restrictions for running other MFL tools or ultrasonic tools through the pipeline, and that is generally by putting a gauging plate through the pipeline. What it does is it takes a look at any bore restrictions. It doesn't provide any of additional information such as the orientation or the location, but instead is simply a tool that is put into the pipeline to identify any potential restrictions that can occur.

Certainly the tools have evolved over time and in many cases a lot of the operators are going with the smart pigs to better characterize the information that is provided.

I have a number of slides here that show the different types of caliper tools that are available on the market. Some of the points that I will be making in this discussion is the ability of the tool to not only identify the location of these anomalies, but to provide the best information related to accurately characterizing the axial extent, the circumferential extent, and the profile of the dent.

What happens is that we are now able to apply some engineering critical assessment methods to evaluate the strain associated with dents that can be relied upon for making decisions as to whether or not to excavate and also to prioritize the severity. When we talk about the strain within a dent we're really talking about the inverse and the radius of curvature of that dent. What that means is a relatively short type dent is going to have a high strain. And is generally more of a concern than a longer, shallower type of dent that could be identified in the pipeline.

On the left side here we have some T. D. Williamson tools. You can see here that these particular tools have sensors mounted within the cups. And what happens is as the cup rides over the deformation it affects the associated calipers within the tool.

Here's another tool for Magpie. You can see here that there's a whole ring of sensors that goes around the circumference, generally spacing of one to two inches is what we're finding with a lot of these technologies. And I think it's important to point out that when I said earlier that we're taking a look at the different integrity threats, one tool is not always better than another. It depends on the specific integrity threat that you're addressing, and also what information you need to get. So just because this one isn't a cup, certainly that may be adequate for the needs of inspecting that pipeline system.

This is a BJ tool here. You can see here that it has offset paddles, they are about two-inch wide paddles. You can see here that there's two rings of sensors here, separated so that you have 100 percent coverage around the pipe circumference. So what you're doing is you're evaluating the peak depth of any deformation over a two-inch wide band. And again in many cases that may be adequate.

If you get into the Tuboscope tool, these have evolved into what I believe they're calling now mechanical damage tool, and you can see here the relatively small sensors, you can see the tight spacing of those sensors around the pipe circumference. And again I'm not always pointing out the latest and greatest technology of all the vendors, but instead how it's evolved over time.

We also have a number of wheel sensors. One of the benefits is that these sensors actually roll along the pipeline. You can see here the configuration of the sensors on the trail end of this particular tool and over here. What you can see here is there are two wheels, again supported by one cantilever. Again, we're going to be measuring the maximum deflection identified by any geometric changes that may be identified in the pipeline. Generally speaking, these are about one to two-inch spacing around the pipe circumference.

This is a Rosen tool and it's called an eddy current proximity detector. What we have here is we have both a sensor and a lever here. The beta being the displacement, and the sensor being the gamma here, combining both the signal count from the sensor with the deflection and getting a compensated signal. The point here is that it's trying to better characterize the deformation and to get a profile that best reflects the geometry of that particular location.

I mentioned the field analysis. Certainly one of the characteristics of gathering the data is to have accurate measurements of the deformations and geometric changes in the field. There's a number of ways that those can be measured. Generally, using a straight-edge or some type of ruler is used to characterize the deflection around the pipe circumference and the orientation.

One point that's worth noting is that when we go out to validate dents and deformations, it is slightly different than what we find with metal loss and/or cracking. The reason being is that the dent size is also a function of the internal pressure, so for one pressure when the tool goes by and we are at a different pressure or reduce the pressure when we go out and do the subsequent excavations, there's going to be a change in the dent size. So we also have to consider that.

In the case of rock dents, obviously once we remove the dent we're going to have a different dent depth. And, therefore, we also have to account for that.

And, lastly, one of the other important factors in a lot of the work that has been done in the analysis of dents is what pressure the dent was--what pressure the pipeline was at when the dent occurred. For example, if we have a pipeline that is at zero pressure and we puncture it or we hit it with a backhoe, we're going to have a significant inward deflection and then it's going to re-round once we put internal pressure on the pipeline.

If there's a lot of pressure on the pipeline when we put a backhoe tooth against it, there's going to be some resistance. So the actual dent depth is going to be different depending on what pressure the dent occurred at and what pressure it's operating at when you go out and take your field measurements.

As I mentioned before, one of the main reasons for running some of the higher definition or higher resolution geometry tools is to best characterize the type of deformation that we have in the line. You can see here that we have a grid that's been established to characterize the particular dent, from this you can define an element analysis, you can do strain analysis, you can use it to make excavation decisions, you can use it to prioritize excavations.

So, the higher the resolution data that we have for characterizing the dent, the more analysis that we can do on those. It should also be pointed out that when we go to do these analyses, sometimes we need to get additional material property data. For example, if we're going to do finite element analyses we also need to acquire true stress true strain data. If we're going to take a look at defect size and material toughness, not all that information is readily available. So, it's important to note that there's a whole combination of factors that go into the analysis of this data.

Certainly detection is one of the areas--how big of a dent are we likely to find. In this particular case they can be as shallow as .1 inches. I think that has gone down from about a quarter of an inch. I think the regulations require a quarter of an inch or two percent. Certainly going down to .1 inch can be achievable in some situations. There are a number of factors that contribute to that. For example, if you have seamless pipe, if it is not controlled rolled steel, you are going to get a lot more variability in the pipe wall thickness. So the ability to detect relatively shallow dents can be more problematic. But, in general, the tool vendors are able to detect something as shallow as about .1 inches.

In terms of sizing accuracy, and this is primarily based upon the pull through test that the vendors have performed, 85-90% of the anomalies are specified by vendors to be within plus or minus 1% of the outside diameter. That's about a quarter of an inch, I think, for 12-inch diameter pipe.

Vendors are also moving toward reporting the depth accuracies as linear measurements as opposed to percent of diameter. That is, they are reported to be 30 mills, or .03 inches, or 100 mills which is .1 inches. And this is based upon the electro-mechanical arms and being able to measure the displacement by the geometric information.

As was pointed out in some of the prior discussions, both in the MFL tools and in the ultrasonic tools, those tools are also capable of detecting geometric changes in pipelines. We've worked on a number of projects where we've been able to integrate the data with those inspection technologies. We also correlate those to geometry inspection surveys and that moves toward the whole data integration, which is a key part of the integrity management rule.

A lot of times these other tools can respond to relatively shallow dents. I mentioned before that these tools are generally capable of detecting dents on the order of .1 to .25 inches, when in fact some of the other tools may be able to detect but not characterize or size even smaller dents than that.

Metal loss and the combination tools are now becoming more common. Prior to now we've had to manually integrate data from other inspections with caliper runs. I mentioned that a number of combo tools are now being developed to combine those results.

This is an example of the combo deformation tool. I believe this one is from CPIG and I believe that this one is from Rosen, taking a look at combination of MFL and caliper surveys.

I talked about this briefly and this is what I meant by some of the capabilities of other tools. That if you have it at a line where you don't expect to have a lot of deformations, possibly running another technology just to locate the dents is a reasonable option. In this particular case you can see the echo losses of an ultrasonic wall measurement tool. You see the echo loss associated with the deformation. I mentioned before that you can't size it, but you do get a feel for the axial extent and circumferential extent of the deformation in the line.

This is an example of a case where a wrinkle was identified and this was a failure that occurred about four years ago. This was a hot oil line that was then laid up with number six fuel oil. As a result we had a wrinkle here and due to the thermal cycles on this pipeline, produced a through-wall crack at the root of the buckle.

Again, wrinkles and buckles, this is through a C-scan from an MFL tool. One thing that is worth noting is that you can imagine that as these tools ride over these types of deformations, the amount of sensor lift-off that occurs if it is moving at the range of three to five miles per hour.

This is an example of a gouge in the side of a pipe. This is an MFL scan right here. You can see that there's no metal loss detected from that location, but if you look at the type two sensors, you can see some minor deflection that has occurred at this location. The point here is that when you run the tools, you use the data that are available to the best of your ability. However, if you were to go back, if this location were to subsequently fail, one can certainly point out that, "Well, look, it's right there." But if you put this in the context of hundreds of miles of inspection, you need to be able to go back and justify the decisions that were made.

Validating sizing--I mentioned briefly before some of the difficulties in validating the sizing of deformations that you may have. This is an example of a calibration. You can see here that generally the field depth is shallower than that reported by the caliper tool. And this is a case where they were primarily rock dents.

In conclusion, different tools provide data on deformations. We showed how MFL tools detect and characterize to some extent deformations. Ultrasonic wall measurement tools and different caliper and deformation tools must have contours for any type of analysis other than exceeding a depth threshold. What that means is the high resolution deformation tools that are run provides more information to better characterize that dent and perform analyses as needed.

The tools providing information with accurate detection characterizing and sizing are critical. That is that if we are going to move on and to do further analysis, we have to have a high level of confidence in that data.

You need to understand the factors that contributed to the anomaly. I pointed out that the subject matter experts between the engineering, the operations, the vendors, the field--we need to understand why we're getting this information. If any one of those work in a vacuum you can see how it's going to be very difficult to tie it all together to best assess that particular integrity threat.

And last but not least, there's no silver bullet. We use these inspection tools to the best of our ability, to run them through the pipeline, to gather data, to analyze those data and to make the best engineering decisions possible.

M: Thank you, Pat.

Pat Vieth: Is that good timing?

M: Remarkable. Exactly twenty minutes.

Pat Vieth : All right.

M: Let's hear it for Ohio State. I don't know if you're aware of the fact that Mr. Swank is a Buckeye as well.

Pat Vieth: I did happen to know that.

M: That kind of surprises me. I thought all you smart pigging guys would have gone into departments on Razorbacks. This is pretty funny stuff up here. Come on.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: We now have ten minutes for questions for Pat. Anybody on the panel have a question for Pat?

Greg Swank with BP: Pat, in your experience on ILI tools, what's the success rate of ILI tools running three-phase pipelines and how much does a constant speed rate where your pressure, if you have some gas that runs through this pipeline to accelerate on a tool run, how much does that affect the data gathering and the ability to understand what that data is?

Pat Vieth: The answer to your first question, and I don't have numbers, but to the best of my knowledge that running these tools in three-phase lines has worked very well in particular on the North Slope, and I think that that's a pretty fair assessment. Someone here may have some better information on that.

The second question was data on the speed excursions. From a speed excursion standpoint, that can always pose some problems. If you're operating within speed excursions on the three to five mile an hour range, generally speaking, those types of variations are not a problem; however, if you get hung up going through a bend or through a valve and you have instantaneous speed excursions, you're going to have some data degradation through the time of that upset condition. So, you know, it depends on the severity of how the tool was logged or the excursion itself. But if you are operating in a range of three to five miles per hour, that's typically not a problem.

M: Does that answer your question? Other questions from the panel?

All right, thank you very much.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

M: So these questions are going to Pat. The first question: You say that ISI is not the "silver bullet". Is there a silver bullet?

Pat Vieth: No, there is no silver bullet in performing in-line inspection for addressing any single integrity threat. It involves identifying the integrity threat, the cause of the integrity threat, identifying the technologies known used to identify and characterize the threat, and from that, applying the engineering decisions based on all the know parameters. Secondly, you also have to consider that you might not have 100% detection and/or characterization and/or sizing with any of the technologies that are relied upon.

M: Any comments from the rest of the Panel? Okay, Alright, I think you've answered the second question, but let me just state it, then if you've answered it, just let me know. If no silver bullet, what would a balanced inspection plan look like?

Pat Vieth: Yeah, I think I did unfortunately cover that, in part of my response. And truthfully what it is to understand the integrity threat, for example, to run a tool and simply look for dents, well, that's one approach, however, trying to determine what the cause of those dents are, are they bottom side rock dents for example, where possibly you could have degradation of the coating and have some other effects to the external pipe surface whether it's cracking or corrosion. Are they topside dents where you could have a possibility of third party damage in there, or whatever the case may be. So understanding the cause of the integrity threat and the appropriate technologies is the best approach.

M: Okay. Any comments from anybody else? They are smart pigging the building. Is there a standard interval for ILI?

Pat Vieth: No, there is not a standard for intervals for performing in-line inspections. Like Jon alluded to earlier, the regulations, U.S. regulations require, I think, a five year interval on the liquid side and a seven year interval on the gas side. What the regulations say is that you need to justify those reassessments--that is, if it's five years you need to go through the analysis to justify that you can go that five year period without another inspection.

While there aren't necessarily any requirements on how you establish those based upon having a process to address each integrity threat, take a look at the growth mechanism and then determine whether or not you can go through a five year time interval for that inspection to reoccur. For example, if you have external corrosion you've run your MFL survey, you have identified locations where you have external corrosion. You have remediated those locations that require it. From that you need to take a look at expected corrosion growth that you would have there to justify whether or not it's feasible to go through the five year interval.

M: Okay. Comments from any of the other panelists? Okay. Next question. Who determines how defects are graded or categorized? The pig vendor or the pipeline operator/owner? Hold on a second.

Pat Vieth: Is my 25 minutes up? That's a University of Michigan alumni.

M: Do you want me to repeat the question?

Pat Vieth: No. I heard the question. That usually occurs at the time of the contracting. It is generally an agreement that occurs between the operator and the vendor. In many cases the vendor has a standard catalogue or listing of anomalies and how they're classified as a result of the inspections. The operators may require some grouping or further classification of those anomalies through some technical specification that may be supplied as part of the request for proposal or bidding process. So it's really a joint project between what the operators--how they want them classified and how the vendors or ILI vendors typically provide those results.

M: Yes, sir.

Bill Flanders: I'd just like to make a comment. When you assess the order in which you dig, or if you should dig or should not dig, to me that's the operator's responsibility. And the operator takes the responsibility for--even if the vendor determines the interaction link between pits which can change the results of the analysis or if the operator chooses to use RSTRENG, he should validate whatever method he chooses to prove to himself that the corrosion mechanism that he's seeing on his line is appropriately and conservatively addressed by those tools that he's using. Whether it's B31G, RSTRENG, or whatever. And that the interaction links are also appropriate. It's a two-part process. It's the length and the depth that determines the rupture capacity of a pipe. He needs to assure that the technology is appropriate in getting him conservative answers.

Pat Vieth: I'll follow up with that, too. I think part of the question I was answering was the classification of the different anomaly types that are identified through the different in-line inspection tools. Certain MFL vendors may call them dents, deformations, whatever that might be. I think that was part of what that question was addressing.

M: Okay. Other comments? Okay. I'm going to describe something to you--hopefully accurately. Okay. Can you hear me over this noise? Okay. I'm going to describe a pipeline for you. This is a pipeline buried with no expansion joints, with three T's in line for produced water supplies and four well patterns. Are you with me so far? A gauge ring was run through this line and showed damage that would not allow for a smart pig. Now I think this is the question. Will caliper tool identify egg-shaped pipe and locate problem areas? I may have messed that up because I actually gave you the definition of something after the question.

Pat Vieth: Did you say that it could not be in-line inspected?

M: If I did it's because I read it off this card. Okay. Let me just read this the way it's on the card. Maybe I'm smarter than I need to be here. Will caliper tool identify egg-shaped pipe and locate problem area? This is a buried pipeline with no expansion joints, with three T's in line for produced water supply to four well paths. A gauge ring was run through this line and showed damage that would not allow for smart pig.

Pat Vieth: I think it's a bottom-line question as to whether or not these tools can detect and characterize ovality in pipe. And the answer to that part of the question is yes. Maybe I don't understand the question, but I don't understand what everything else in it is in here. Especially given the fact that a gauging tool was run and could not--identify that the line could not be pigged.

Frank Sanders: If a gauging pig comes out damaged, typically there's different size of gauges so that one pig that's hit can go to the size of the item that hit it. So if it comes out damaged you need to take a look at the specifications on your caliper pig to determine whether or not it can be run. So I don't know if that meant he was referring to in terms of a smart pig he was referring to an MFL pig or a caliper pig. Because the bore restrictions on an MFL and caliper pig can change drastically. So, maybe an MFL pig couldn't be run but a caliper pig that can definitely detect the ovalities it might be able to be run.

M: Okay. More from you Pat?

Pat Vieth: I think we answered the question to the best of our ability.

M: Okay. Now, this is the last question for you. And I'm not too sure I can ask this question clearly. It's not real clear to me. Sort of like the last question. Okay. All right. This is something that apparently you said in response to a question--or no. Somebody had made a comment and then you came back with a report. And it says here--it says, I think it's 3:00 mechanic--m-e-c-h. Mechanical, I guess that's mechanical--damage showing on secondary sensor noted in your presentation and asked about during Q&A you intimated that even ILI data might be useful "after the fact" if the pipe eventually failed. Are you in the ballpark with me on that? I haven't asked the question. The question is very clear. The background was a little unclear as to what exactly was being answered. Why was it uncovered and stripped unless someone made the presumption that the defect was something more than "light" internal metal loss?

Pat Vieth: Actually that came up in some discussion during the break. And actually I don't fully understand why that location--that specific location was excavated. It could have been for a number of reasons. Possibly there's excavations going on in close proximity to that. For example, if they had done an excavation in response to external metal loss or internal metal loss, and as part of uncovering that area and stripping back the coating they came across this mechanical damage. They then went back in and looked at the ILI data and they were able to see that there was really no indication.

The question then would become did the ILI tool and/or analysis miss something? Going back in there and looking at the data itself you can see that the type 1 sensor there was no indication of metal loss. You saw the type 2 sensors which would identify any possible movement or any deformation of the pipe, for example, the sensor movement would be detected there--did have some indication of an anomaly in that location.

The point that I was trying to make there is that when we look at hundreds and hundreds of miles of in-line inspection data, whether it's MFL data or whether it's UT data, whether it's crack detection data, whether it's geometry and caliper or deformation data, that the processes are in place for the vendors to detect, characterize and size the anomalies. There are processes in place for the operators to respond to those anomalies. But at the end of the day you're never going to get to 100% confidence regardless of what combination of technologies you use even beyond in-line inspection, including hydrostatic testing.

However, in the unlikely event of a future failure, you can go back in and zoom on this very small area and say, "Well, there was something there." And that was part of the point that I was trying to make.

M: All right. Any comments from the panel? Pat, thank you very much. Jon? Jon, speak right into the microphone.

Jon Wharf: Just on a couple of points that--you can also tell a lot more about a C tool location once you have a definite location to go to. So if you know somewhere to look you can look at that location and maybe make some discernment about what the ILI was doing at that point from the benefit of hindsight and the knowledge of what was actually on the pipe.

Whereas, if you are looking at, as Pat was saying, hundreds of miles of data, you can't go to that level of detail on every point of the data that you are either attempting to read or report on in a timely fashion. That wouldn't be feasible and it wouldn't be the most effective way of assessing the data. The other point is kind of associated with that, is that we have seen cases where we have come across a feature in data that is associated with a re-inspection of the line. And we're able to go back and look at the old data and although there was no--the report did not mention it at the time, reassess that data given that we now have a location and say, "Well, it was something." Or there was absolutely nothing there previously and that makes a judgment about what's happened to the line in that interval.

M: Any other comments? Pat, anything else? Any other comments from the panel? Thank you very much, Pat. And you're off the hot seat for the day.

M: And I just want to point out that this is for Pat Vieth. And that the only thing between us and the happy hour is your answer. So, it starts with: Please briefly describe the techniques used to verify the location of the pig from outside the pipe.

Pat Vieth: Just location verification of anomalies?

M: Please briefly describe the techniques used to verify the location of the pig from outside the pipe.

Pat Vieth: Is this just pig tracking? Well, this is about a half-hour answer. I can do it. Now, there's--all the tools use a pig tracking device where they have trackers located along the pipeline and from that they can do estimates of where it is. They can track it when you put it through a pipeline. Because, as we've said many times, that once you have an anomaly that couldn't be identified in the pipeline, tying it back into a known physical location is very important. Once you get into the physical location, as Jon and Mark alluded to earlier, you then have your girth weld indication that is used to reference it more closely on the pipe joint. So it's ample sequence of stuff that all the pigs are tracked through above-ground markers throughout the whole operation.

M: Yes, please.

Chris Dash: We're lucky on the North Slope they have one additional way of locating damage and that's every 40 feet or 60 feet we have a VSM. So we can narrow it down much more quickly than just using AGM's and casings and valves.

M: Any other comments?

Jon Wharf: Unfortunately they are invisible to the ultrasonics, but otherwise very useful.

M: Jon, you have to speak into the mike.

Jon Wharf: And in any case, most of the pipelines are very well--have been inspected and have reference information for them, so that would be tied back to any other inspection as that sort of thing happen.

M: Okay.

Mark Olson: I guess just to go a little further into detail on the answer to that question, you can detect a pig passage, or a pig, in many ways. The pig can transmit a signal to an above-ground receiver, above-ground transmitter can transmit a signal to a receiver on the pig. A magnetic pig, you can detect a passage of the magnetic field underground. When the pig is coming toward you, you are detecting the north pole, when it goes by and you're seeing the south pole when it flips if it is right underneath you. You can also detect the passage of the pig physically. So, there's many different techniques, depending on the application, so it's pretty standard technology.

M: Okay.

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MANAGING RISK DNV

Geometry and Deformation/Caliper Tools

Intelligent Pigging of Pipelines Conference

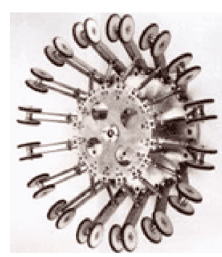
Patrick H. Vieth
Martin Phillips, Ph.D.

13 November 2006

Outline

MANAGING RISK DNV

- Potential integrity threat of deformations
- Geometry/Deformation/Caliper tool design and function
- Other ILI tool capabilities for detecting deformations



Geometry/Deformation Integrity Threats

MANAGING RISK DNV

- Smooth/sharp dents – constrained and unconstrained
  - When the indenter remains in place & prevents re-rounding, the dent is constrained
  - Dents close to or on a weld are considered more severe
- Dents with metal loss and/or cracking
  - Mechanical damage with metal loss/cracking does not always cause a measurable dent
- Buckling due to pipeline displacement
- Wrinkling when field bending pipe

Version 11 November 2006 Slide 3

Smooth Dents – Constrained/Unconstrained

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Version 11 November 2006 Slide 4

Mechanical Damage – With Cracking & Deformation

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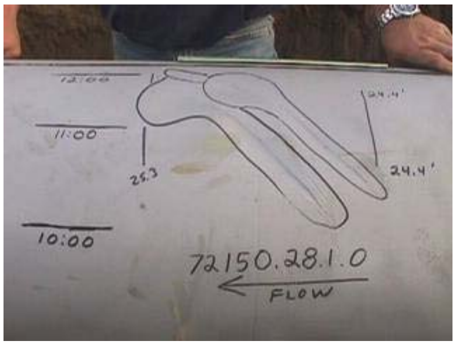

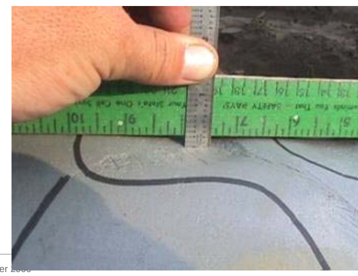

Mechanical Damage - No Denting

MANAGING RISK DNV

Deformation tools are referred to as 3rd party (mechanical) damage detection tools but not all 3rd party (mechanical) damage causes a reduced bore sufficient to be detected by geometry/deformation tools

Buckle and a Field Bend Wrinkle

Geometry/Deformation/Caliper Tools

- Tools are designed to give an *indication* with changes in a pipe bore
- Need to measure <OD and >OD
- Systems with inertial equipment can also map pipe directional changes and give GPS information

Geometry/Deformation/Caliper Tools

MANAGING RISK DNV

Courtesy of TD Williamson

Courtesy of Magpie

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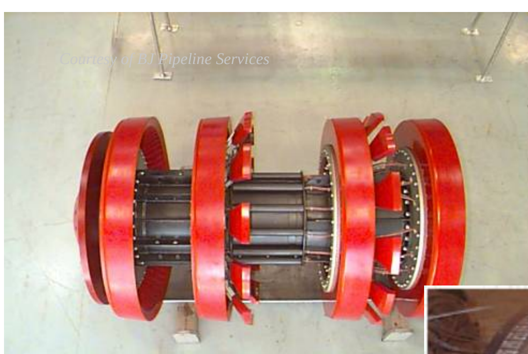
Geometry/Deformation/Caliper Tools

MANAGING RISK DNV



Courtesy of Tuboscope Pipeline Services

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Geometry/Deformation/Caliper Tools

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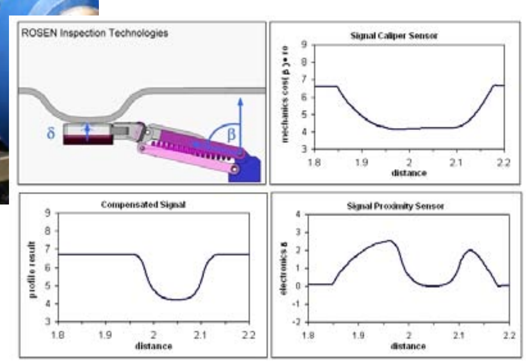
Wheel sensors

Changes in Technology

MANAGING RISK DNV



Data Analysis

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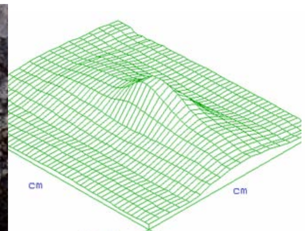
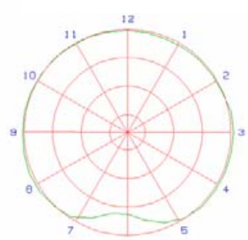
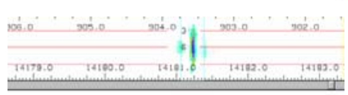
The cause of the change in pipe bore is part of the analysis process

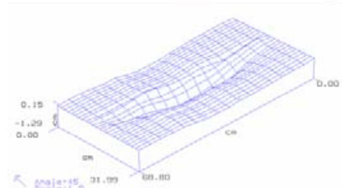
Geometry/Deformation Tool Data

MANAGING RISK DNV



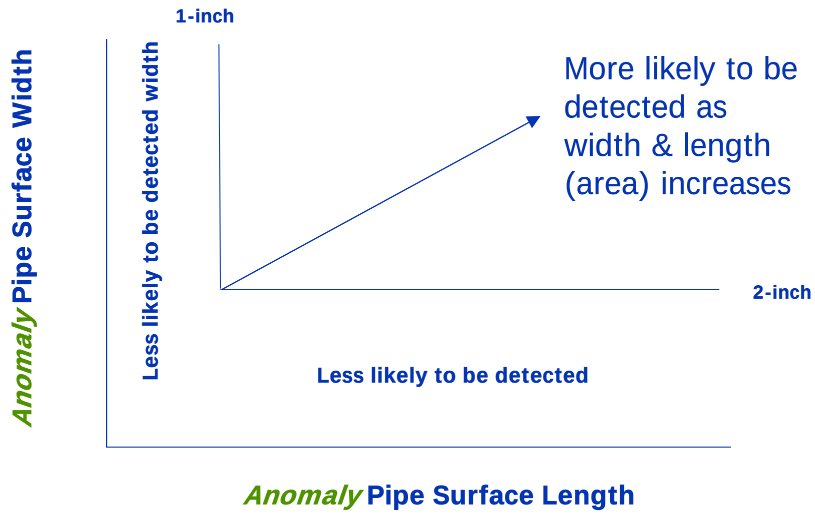






Deformation Length & Width Detection Thresholds

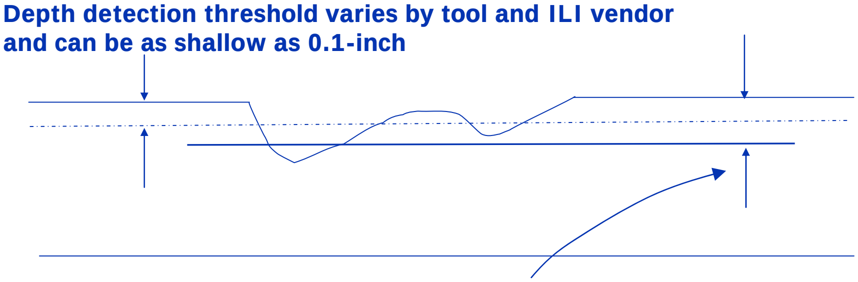
MANAGING RISK DNV



Deformation Depth Thresholds

MANAGING RISK DNV

Depth detection threshold varies by tool and ILI vendor and can be as shallow as 0.1-inch



Reporting/sizing threshold is usually deeper than detection threshold and varies with type of *anomaly* (dent, ovality, wrinkle) and pipe diameter. A reporting threshold of 2% OD is often given

Max Depth Sizing & Accuracy

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- 85% - 90% of anomalies/imperfections are specified by vendors to have a depth within ±1% OD
- Vendors are also quoting depth accuracies as a linear measure instead of % OD, e.g. ± 30 mils, ±100 mils, or ±110 mils

Other ILI Tools

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- Other ILI tools designed to detect metal loss or cracking also respond to deformations
- These tools (MFL, TFI, UTWM, UTCD) can often respond to shallow denting and also identify associated metal loss or cracking but this is not guaranteed
- Metal loss/geometry/deformation combination tools are now becoming common
- Metal loss/cracking tools with inertial equipment can detect/monitor pipeline displacement/out of straightness

Combo Deformation Tools

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Combination MFL and deformation tools

UTWM - Image of a Dent

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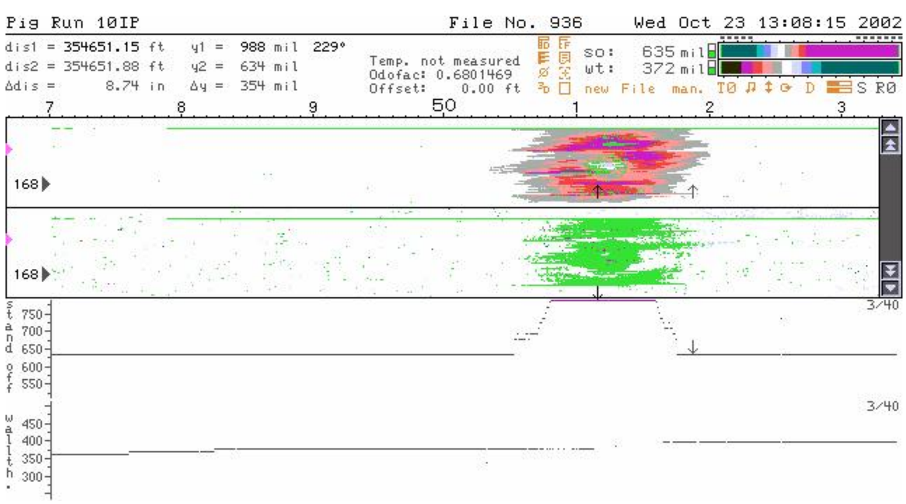

Dent depth is not measured

UTWM – Wrinkle/Buckle

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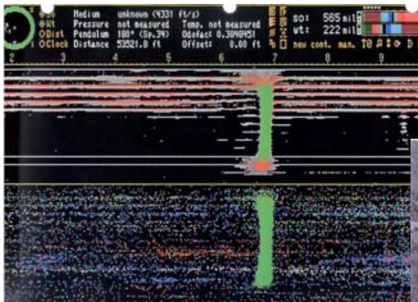

MFL – Wrinkle/Buckle

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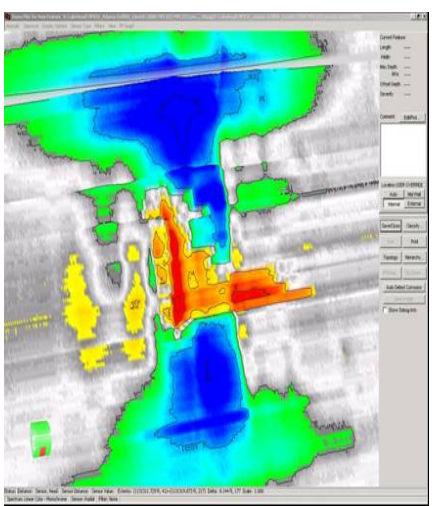
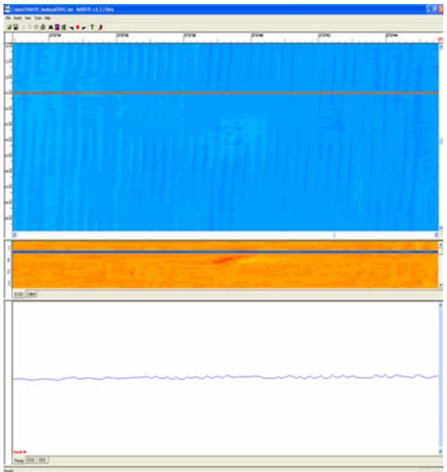


MFL - Dent with Axial Gouge



Validating Sizing

- Measuring deformations in the field is influenced by:
  - Line pressure for unconstrained deformations (usually top-side), and
  - By a combination of removing the constraint and line pressure for a constrained deformation (usually bottom-side)
- Removing a constraint (e.g. a rock) causes the pipe to spring back even when the line is at atmospheric pressure

Caliper vs Field Validation Example

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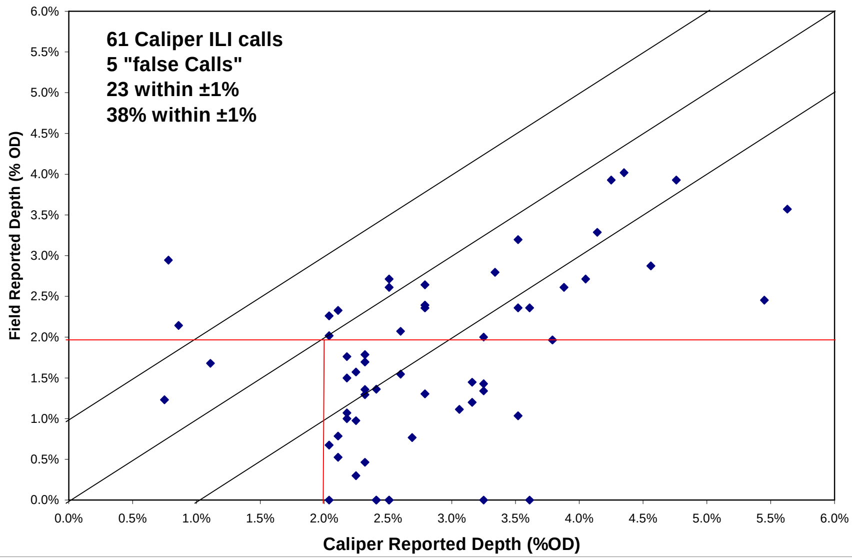

Dent Curvature & Strain Calculations

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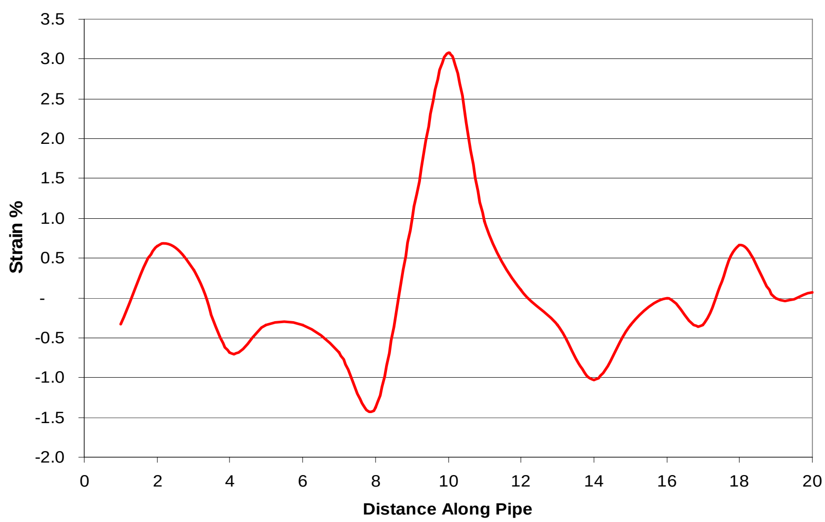

Conclusions

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- Different tools provide data on deformations
- Must have contours for any type of analysis other than exceeding a depth threshold

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APPENDIX I

INTELLIGENT PIGGING CONFERENCE PRESENTATION 4

REGULATORY REQUIREMENTS AND STANDARDS FOR SMART PIGGING

JON STRAWN OF U.S. DOT OFFICE OF PIPELINE SAFETY

ABSTRACT OF PRESENTATION 4

Regulatory Requirements and Standards for Smart Pigging

Speaker Name: Jon Strawn, Senior Engineer/Project Manager, Alaska District

Company Name: U.S. Department of Transportation (DOT) Office of Pipeline Safety (OPS) Pipeline and Hazardous Materials Safety Administration (PHMSA)

Website URL: **www.phmsa.dot.gov**

Type of Business: The DOT Pipeline and Hazardous Materials Safety Administration has public responsibilities for safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines.

The Hazardous Liquids Integrity Management Program, promulgated by the U.S. DOT-OPS-PHMSA, establishes rules for Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators (49 Code of Federal Register (CFR) Part 195.452). These rules, effective May 29, 2001, and February 15, 2002, specify regulations to assess, evaluate, repair and validate, through comprehensive analysis, the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, unusually sensitive areas (drinking water or ecological resources) and commercially navigable waterways.

TRANSCRIPT OF PRESENTATION 4

M: The next presenter is Jon Strawn, of the Unites States Department of Transportation- Office of Pipeline Safety- Pipeline and Hazardous Material Safety Administration, and he'll be providing us an overview of regulatory requirements and standards for smart pigging. Jon is a senior engineer/project manager in the Alaska district office. Jon has a Bachelor's Degree in electrical engineering and a Master's Degree in business administration from Utah State University. He has held a regulatory position in pipeline safety in Alaska since 1994 and previously with the Utah Public Service Commission since 1980. Jon?

Jon Strawn: Thank you. Good morning. I hope everybody's had a good break. I have to admit I kind of have a headache after listening to the first session and how technically complicated that is. Hopefully, mine won't be that technically complicated.

I would like to think of myself as maybe--as a humble public servant that's just trying to give you taxpayers their money's worth. So, I hope my presentation may be able to fulfill a little bit of that.

Wow. When I saw that picture I looked at that and said, "I'm not exactly sure what that is." Maybe it looks like something from Mars or, I don't know, maybe it looks like a Google Earth picture of Hawaiian volcanoes. But actually it's internal corrosion. And that point there is-when I first looked at I said, "Well, this is not in my opinion, for me this is not a Pigs-R-Us class but relates to integrity management." Not only that, that's public enemy number one, which is one of many which is an integrity threat to the pipeline. It's one of many which we see as threats to the integrity of the pipeline.

It's also in a way Mission Impossible for us, so as the government would come in and have it, we're on a Mission Impossible here trying to deal with threats to the pipeline.

So, before I get started, though, there are two publications that are out in the lobby that's on the desk out there. One of them is a kind of a fact sheet about the integrity management program and the other one is about a lessons learned presentation that Bruce Hanson gave back in the summer that has kind of an update of the integrity program. And it has--I'm sure both of those will answer any questions that you might have afterwards, so I would encourage you to pick up those two papers.

The mission of the office of pipeline safety, then, is to ensure the safe, reliable, and environmentally sound operations of the nation's pipeline infrastructure system--transportation system. Our hazardous integrity management role establishes rules for pipeline integrity management in high consequence areas for pipeline operators. These rules specify regulations to assess, repair, evaluate and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments in the event of a leak that could affect populated areas.

So the integrity management rule as it's written, and I want to be clear about this, it's not a pigging program, it's not a pigs-r-us. It's how do you manage the integrity of your pipeline in high consequence areas.

The goals of the integrity management rule are four: To accelerate the integrity assessments of pipelines in high consequence areas; to improve integrity management systems within operating companies; and to improve the government's role in reviewing the adequacy of the integrity programs and plans; and, finally, to increase public assurance in pipeline safety.

I would like to present an overview of the key features of the pipeline safety rule. I might talk about these key features, a short presentation on that, and get into the requirements for pigging under the code, and then finally a discussion about where we are with the integrity management program.

So, first of all, what does the integrity management program include? It includes identification of segments that could affect HCA's, your integrity management program has to have a framework for implementing IM program elements, and it must include a baseline assessment.

What are the unusually sensitive areas. That can be found in part 195 of the federal code. I'm sure you all have your code books, bible, I'm sure everybody's read it. I, for one, have not memorized that, so if I get any questions I may refer to the people who have memorized it.

Part 195.6 talks about unusually sensitive areas and that those areas are drinking water and ecological resources. Also, a high consequence area is a populated area, high populated in the definition of other populated areas. And other HCA's, commercially navigable waterways.

What are the elements of an integrity program? That can be found at 195.452(f). These are the eight elements, which those of you who have undergone an integrity management inspection by me know that there is eight protocols that we normally go through. These are the eight protocols. One is that your program must identify segments that affect HCA's. You must develop and implement a baseline assessment program which is going to be related to integrity assessment, and I'll deal more with that in a little bit. After reviewing your integrity assessment results, you have to repair or remediate the anomalies that you find. You have to include those into an informational risk analysis and then you have to implement additional preventive or mitigative actions on your pipeline and you have to have a continual process for assessment and evaluation of the risk to your pipeline. And you must continually evaluate the performance of your pipeline IM program.

And one of the deficiencies that we see, at least from my personal standpoint, looking at some of the IM programs is that in many cases--not many cases, in a few cases--there's a lack of process documentations that makes it kind of difficult to understand what the actual process is.

I have taken this particular slide directly from the code. I don't know if you can see that, but it answers the question, "What must be in a baseline assessment program?" And it says, "The methods selected to assess the integrity of the pipe, the operator must assess the integrity of the line by any of the following methods: one of the methods is internal inspection or tools capable of detection of corrosion and deformation anomalies including dents, gouges or grooves. Another method of integrity testing your pipeline is to conduct a hydrostatic test pressure, conducted in accordance with subpart (e) of the code, or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pumping. The operator who chooses this option must notify OPS within 90 days before conducting this type of assessment."

So then what should be in a baseline assessment plan? As for each pipeline segment that you have identified that affects an HCA, you would have to determine the assessment method that you're going to do to determine the condition of your pipe. That can either be an in-line or it could either be pressure testing or it could be other technology.

Then after you have determined which of your pipe segments are in a high consequence area, then you would have to schedule when these segments are going to be assessed and how you are going to assess those segments that affect an HCA.

The code requires 50% of the mileage to be completed by September of '04 for the liquids Category 1 thickness pipeline and all segments have to be--that affect an HCA has to be integrity tested by March 31st of '08. We found that I think the majority of the pipelines are way beyond that schedule and we are in good shape to have the pipelines that affect high consequence areas completed by that deadline. And the code requires that you are to address your highest risk segments first.

What actions must be taken to address integrity issues? An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. On discovery of a condition the regulation requires that an operator must promptly but no later than 180 days after an integrity assessment obtain sufficient information about a condition to make that determination--to make the determination of the condition of their pipeline.

And then, of course, to schedule it for evaluation and remediation according to a schedule. And those schedules are--the first one is an immediate repair condition. I think that we talked about that. An immediate repair condition requires the operator to provide immediate repair. To maintain safety an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions.

These conditions are: metal loss, that is greater than 80% of the nominal wall loss regardless of its dimension. A calculation of the remaining strength of the pipe that shows a predicted burst pressure risk and the established maximum operating pressure of the location of the anomaly. A dent--I think this is what we talked about earlier--a dent located on the top of pipe that has any indication of metal loss, cracking or stress riser is an immediate repair condition. Or a dent located on the top of the pipe of a depth greater than 6% of the nominal pipe diameter or any anomaly in the judgment of the operator that would require them to go in and would require the operator to evaluate the assessment results that would require immediate action. In other words, that's the catch-all. If the operator feels it is an unsafe condition then it is incumbent upon him to go in and make immediate repairs on that pipeline.

The second condition is a 60 day condition. That basically talks to a dent located on the top of a pipe with a dent greater than 3% of the pipeline diameter, or a dent located on the bottom of pipe that has any indication of metal loss, cracking or stress riser.

And the third condition is 180 day condition that is, again, for a depth greater than 2% of the pipeline that affects pipeline curvature at a girth weld or longitudinal seam weld. A dent located on the top of the pipe with a depth greater than 2% of the pipeline and a depth located on the bottom of the pipeline with a depth greater than 6% of pipeline diameter. A calculation of the remaining strength of the pipe--an area of general corrosion with predicted metal loss greater than 50% of the nominal wall. Predicted metal loss greater than 50% that is located at crossing under the pipeline or in an area with widespread circumferential corrosion or is in an area that could affect a girth weld.

For 180 day requirement is a potential crack indication or it is estimated is determined to be a crack or corrosion of along a longitudinal seam weld, a gouge or groove greater than 12-1/2 percent of a nominal wall.

So basically the conclusion from that I copied that directly out of the code to indicate that when you do run a pig and you do identify these conditions on your pipeline, that they have to be classified as immediate repair, 60 day repair, 180 repair. And during that you have to go out and mitigate.

So implementing the assessment plan, you need to perform assessments. You need to integrate results with your other integrity information that you have, and you have to prepare excavation and repair schedules. You have to take appropriate mitigating action to prepare it. You have to gather all that information on the risk analysis and you have to determine the timing and method for the next assessment interval. And that interval has to be less than or equal to five years. And then you have to update your assessment plan.

Some of our results, real quickly, is that PHMSA completed initial integrity management inspections of all large hazardous liquid inspection operators in 2004 and has continued inspection of those small operator IM systems and are re-inspecting our large operator systems. As of December 2005, PHMSA completed an inspection of 175 first-round again with re-inspections and, basically, the conclusion is PHMSA has found that operators generally understand what portion of their pipeline systems can affect high consequence area.

The rule is also having significant benefits in areas outside of HCA's. To December of 2005 operators project that 86% of pipelines have had integrity assessment performed on those 45% that would be affecting HCA's with another 41% that are not affecting HCA's are still getting integrity testing. So 86% of all pipelines are being integrity inspected, so that's good.

This is another busy slide that basically said the manner of methods used for integrity assessment is geometry caliper, and deformation tool and also the high resolution MFL tools is by far and away the method of choice as opposed to, say, the hydrotest or some of the other types of testing that is being performed. After these numbers there has been 1213 immediate repair conditions determined--mitigated. And 725 with 60-day commissions, and a total of 2514 on 180 conditions. So there is a good ‘finding and repair’ record from the operators in the industry.

And, basically, in conclusion, from our perspective the operators have been generally cooperating with open communication, the PHMSA has successfully implemented this programmatic inspection approach versus the checklist--remember the old checklist we used to use, “Are you in compliance; yes or no.” Now we have to go into a programmatic inspection approach which is a lot more complicated for both inspectors and operators. I see you shaking your heads. I think everyone agrees with me.

And this inspection approach continues to evolve and improve. It is certainly a work in progress. And the enforcement approach for most operator program development and approval. So we did continue a management program from a regulatory standpoint is a regular program embraced by the operators. It has good results. And I thank you very much.

M: Thank you, Jon. You finished one minute ahead. Very good.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: Questions from the panel?

Sam Saengsudham, ADEC: Jon, please show us again the slide that shows all the various methods used last year and the MFL was 60 something. So, from this graph it is clear based on most the methods used here this is high resolution MFL?

Jon Strawn: This is high resolution MFL right there. UT somewhat less than that. Calipers, geometry and deformation tools also run----

Sam Saengsudham: So, only one, the UT or other method, not ILI or hydro, allow for 1 percent. We have them on top 1 percent. You have a method allowed by OPS, right?

Jon Strawn: I think that’s digging up well holes and physically looking at your pipe during some type of approved direct assessment to a condition where you would dig up the pipe and look at your anomalies.

That is also found in that paper that’s out there. They talk about that a little bit more. Bruce Hanson wrote that paper and he addresses some of these other methodologies in greater detail.

Sam Saengsudham: So the standard resolution of MFL is not being used that much, only 2%?

Jon Strawn: Which one?

Sam Saengsudham: Right here.

Jon Strawn: Yes, 2% standard MFL. It’s high res.

M: Okay. Does that answer your question? Any other questions from the panel?

Jon Strawn: Thank you. I Appreciate it very much.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

M: The next group of questions are going to session number four. Jon Strawn is going to be on the hot seat and he gave us an overview of regulatory requirements and standards for smart pigging.

And, Jon, I am happy to report to you that we’ve got more questions for you than anybody else.

All right, so the first question that we have for you is what is the smallest segment that is length regulated by OPS (Office of Pipeline Safety).

Jon Strawn: Smallest length----

M: Segment.

Jon Strawn: Segment length----

M: Regulated by----

Jon Strawn: 195.1(c)3 says that if it's less than one mile it's not regulated unless it's in an offshore or a navigable waterway. Somebody hadn't read the code, but I have.

M: I feel like this is Jeopardy.

Jon Strawn: That's the only thing I can qualify. I know the regulation says that you're not regulated if you're less than one mile and unless you're offshore or in a navigable waterway. So what I'm thinking is like Alpine pipeline that would cross the Alpine River--that would be in navigable waterway, so that diesel line there would be regulated even though it's less than--what is it? A mile across. But it's in navigable waterway, so it would be regulated. Bill, help me out here, am I right on that?

Bill Flanders: Right.

M: Any other comments from the panel? Okay. Second question. Is it realistic to only regulate a segment of a pipeline? Is it possible without assessing the whole pipeline?

Jon Strawn: It was planned that way. Yes, that is an advantage to an operator, I believe, to the assessment of--we don't affect an HCA, then that 'stringent' repair criteria). It doesn't apply. But for a pipeline that has different segments, how else are you going to assess it if you don't pig the whole line, or if you don't hydrotest the whole line? So yes, that slide I showed this morning, there's like 45 percent of the total pipe that's in HCA's, but there's 41 percent non-HCA, so it's like 86 percent of the pipeline has been integrity tested. I think that's a good thing.

M: Comments from the other panelists? Okay. All right. When using the phrase, "unusually sensitive environmental areas" does the U.S. Department of Transportation use determinations issued by other federal, state and local government agencies for pipelines on the North Slope? And, if not, why not?

Jon Strawn: I know in some cases we do not follow their requirements for unusually sensitive areas--I'm thinking of maybe EPA that might include other areas that they might consider unusually sensitive areas that we do not. But other cases, like the national census bureau, I know we do follow along with basically what they say, and whatever it is we say, it's put into our national mapping pipeline system and that's kind of our go-by. You know you can look right at the State of Alaska and see if you're in high consequence area as we define it, and determine exactly whether your pipeline segment is in or affects an HCA. So, the answer I said is in some cases yes, and in some cases no. And the ones who are no, I'm not sure I know why. But we don't accept others--all others.

M: Okay. Any of the panelists have any comments? Okay. What are ADEC's plans for oversight of North Slope lines in the future? I know you don't work with the Alaska Department of Environmental Conservation.

Jon Strawn: I don't have a clue, but Sam might. That's a Sam question, I think. No, I really don't know what they're going to do about regulating the North Slope lines. I know that our federal regulations on all other states in the United States we have certifications by state to be part of the DOT program. There are two states, Alaska and Hawaii, which are not part of that certification process. And, so that is basically why we're here with our visibility for intrastate and interstate pipelines. So, I don't know what their plans are.

M: Okay. Well, we happen to have a representative here, so Sam. Any comments?

Sam Saengsudham: Well, to answer the question, right now attending to what is coming into the near future is to flow line regulations. Three phase flow. This hopefully will be signed--become effective sometime toward the end of this year. Regarding the rest of the pipeline, as what we call a crude oil transmission) pipelines. We also have been regulating those lines to a certain extent, so----

M: Any other comments from the panel? All right. Next question. Can you provide examples when other (non-ILI) hydrotest inspection techniques have been approved?

Jon: Other technology that has been approved by DOT--I don't know of any other that's been approved. On my chart this morning I showed that's very, very small and I believe that would get into the direct assessment. And I'm just not aware of that. Some operator may have applied for other technology to DOT, and maybe contractors or something know about that, but I don't know of any other technology that DOT has approved.

M: Bill, anybody? Anybody from the industry side?

Jon: The only thing I can think of, it would be a bell hole of some type of direct assessment before we would approve that.

Greg Swant: I understand in the lower 48 in small sections on property that can't be pigged, some vendors are utilizing--or some operators are utilizing the guided wave technique as an external validation, I guess, of integrity. So that would be other than hydro and ILI. I believe this is in a study with some industry groups on the efficacy of that particular technique.

Jon Strawn: I'm not seeing any other proposals in the State of Alaska for using other technologies, so----

M: Okay. There are a couple more parts to that. I believe the answer to the first part is that they're not relevant here. Okay? Who is held responsible if a vendor does not provide data within 180 days?

Jon Strawn: That's an easy answer. We don't regulate vendors, we regulate the operators, so they would be held responsible for that.

M: And what avenues are there for an extension if technical difficulties occur? On this 180 day period.

Jon Strawn: In Alaska I'll give you an example of a couple of operators where they've applied for an extension and then it was not granted because there was not justification for exceeding that 180 day requirement. And it seems like the industry standard, at least from what I've heard, is that most vendors are able to provide that data within that 180 day requirement. So I'm not sure of what circumstance would be out there that would allow you to exceed the 180 day. Maybe the vendors have something on that.

M: Vendors? Any comments?

Jon Wharf: I guess it depends when do you start the 180 day clock ticking?

Jon Strawn: The 180 day clock ticking is when--if you are going to run a suite of logs, when the last pigs come out of the line, that's when the clock would start and have 180 days then to provide data back to the operator. And we have--we ask the operator to have processes and documentation in place to make those requirements of vendors to get the data back in the reasonable amount of time--within that 180 day period. I haven't heard of anybody that couldn't do that. And I have had them do it as quick as just a very few days turnaround on that ILI data.

Jon Wharf: It's a matter of the last run of the series of runs on in-lines that occurred? There shouldn't be major obstacles in that. It would be very unusual circumstances. And I would just say that in that case, I'm sure they could come out to you and explain what the circumstances were and make a good case for something--for the extension.

Frank Sanders: If you have a special circumstance where you're actually expecting to find significant features that would either need 100 day or whatever. In the contract stipulations you can also have a special request where it can expediate a preliminary report and have the ILI vendor have their analysis planned over time or doing whatever they have to do to get that report out as quickly as you can. So there are special requests possible.

M: Jon, any comment?

Any other comments from the rest of the panel?

Mark Olson: I think that there is a lot of commercial motivation for the vendors to get their reports in much quicker than 180 days, so while the vendors aren't the ones being regulated, there's big commercial terms and conditions that are at stake. And so maybe the carrot and stick may be a little bit different, but I just never heard of a situation where it took more than 180 days.

M: Okay. Any other comments? All right. For high pressure--or--Are high pressure gas pipelines likely to come under the same regulations as hazardous liquid lines?

Jon Strawn: What was that question again?

M: Okay. I think I have the question right. I'm taking some liberties with it because it's not real clear to me, but I think it says, Are high pressure gas pipelines likely to come under the same regulations as hazardous liquid lines?

Jon Strawn: And the answer is yes. There is a gas IMP rule out there. In some cases the requirement's a little bit different than integrity management, but basically the concept is the same--that the high pressure transmission lines in a high consequence area--and they are defined a lot different than what the liquid lines are, but yes there is a pipeline program--gas IMP program--that's out there in place.

M: Okay. So it's already in place. I thought that maybe it was due and we could expect it in the future?

Jon Strawn: Pardon me?

M: The second part of the question was to discuss the timeline of those regulations. But you're saying they are already in place?

Jon Strawn: Yeah, it's already in place. I haven't conducted any gas IMP inspections yet, but that will probably in '07 and I think we have probably seven natural gas operators in the State of Alaska that would come under that gas IMP program.

M: Okay. Any comments from anybody else on the panel? Yes, please.

Mark Olson: If I remember right off the top of my head, the gas IMP rule is actually it's quite a ways down the road. I think the first 50% of the mileage has to be done by December 17, 2007, so they're already two and a half years in?

Jon Strawn: But there's still quite a bit of time to get all your baseline assessment. Is Dave agreeing with Enstar here?

Sam Saengsudham: IMP right? What you say is IMP, right?

Jon Strawn: Yes, that's Integrity Management Program for gas transmission lines in high consequence areas.

M: I wonder what's going on upstairs here? Okay. All right. This is a two-part question, I believe. Is there a requirement (either federal mandatory or industry standards) to smart pig an OTL within a given timeframe. For example, every five years. Make sure everybody knows what OTL stands for.

Jon Strawn: It stands for oil transit lines. I'm not clear. As of right now this would have to be a transmission line that operates greater than 20% of the minimum specified yield strength to be regulated. So it means BP lines, OTL lines, would not be regulated now. We have new regulations out which the final rule has been written, it's out to the public, and the end of that period is sometime in November. I think November 6 or 7 or something like that and DOT will put the final rule together and submit it to Congress. But I would think that rule for the low stress OTL lines would be on fast track. And so they would be regulated.

M: Okay.

Jon Strawn: I'm not sure I answered that question.

M: Well, I think they're just wondering if there is a requirement for how often they have to be----

Jon Strawn: Oh, well. Then if that--I haven't read the new regulations yet but I assume it would be that you would have a year then to get your pipeline--have your baseline assessment and your program put together, and then I think it's five years you would have to have that baseline assessment done.

M: Okay.

Jon Strawn: Am I right on that, Bill? I think that's the requirement.

M: Okay.

Jon Strawn: I'd have to look at the code reading to check on it, but I think you have a year after you determine that you have to comply and then five years to get your baseline assessment completed.

M: Okay. Now part two of the question is--let's assume that those timeframes that you just mentioned are, in fact, ones that are being envisioned. Are they enforceable from your perspective? Are the timelines in the regulations enforceable?

Jon Strawn: To answer that one, yes. If the regulation requires that then that would be enforceable.

M: Okay. We were hoping you would say something along those lines. Okay. Next question. Will you describe the applicability of a pressure test for characterizing integrity of a pipeline?

Jon: Would I characterize the----

M: Would you describe the applicability of a pressure test for characterizing integrity of a pipeline, from your perspective.

Jon Strawn: The pressure test? Do I agree with the pressure test? Hydrostatic test is a good idea. That's not my favorite, if I understand what your question is. You can also see by that chart that's not the favorite method of determining the integrity of your pipeline. There are some distinct disadvantages. And my opinion on that is that you're putting tremendous stress on a pipeline by hydrotesting, especially if it's an old pipeline. It's really not going to tell you about the extent of the corrosion or it's not going to tell that it can fail for some reason tomorrow. Only that it passed the hydrotest today. But there are some pipelines in Alaska. I'm thinking of Cook Inlet pipelines that cannot be pigged and so their only choice is to hydrotest it.

M: Okay. Anybody else on the panel have anything to add? Okay. The code requires pipeline operators to develop and implement a baseline assessment plan. First question: Why does the code allow for baseline assessment via pressure test?

Jon Strawn: I believe as I just tried to explain here, is that because the pipelines are not piggable then that is another viable test to demonstrate the integrity of your pipeline.

M: Any comments on the answer? Okay. This is a several part question. Wouldn't pressure testing if used alone only show whether the pipe has a hole or not?

Jon Strawn: Would pressure test only indicate that it has a hole?

M: Wouldn't the pressure testing if used alone only show whether the pipe has a hole or not? That's the question.

Jon Strawn: I have to think about that just for a minute. Pat, jump in there.

Pat: I'll start out by answering that there is no silver bullet, including in-line inspection and hydrostatic testing. Hydrostatic testing is done to a level above your operating pressure--typically 125% of your operating pressure. It is designed to be a destructive test, and that is it's going to remove significant defects from the pipeline. Very similar to in-line inspection, you have to take a look at reassessment intervals and what you need to look at there is depending on the integrity threat--whether it's cracks, corrosion--whatever it may be. To take a look at a defect that could have just survived the hydrostatic test, apply the growth mechanism to that, and determine what your reassessment interval is. So it is a parallel to in-line inspection, and certainly there's benefits and limitations of that technology, just like you see with other approaches. Does that answer the question?

So, the answer is if it's only a hole? That's correct. If it does have a hole in the pipe, that will be detected in a hydrostatic test.

M: Okay. Do one or the other of you, or anybody on the panel agree with this? If there is no hole, pressure testing would not provide info on corrosion spots. Is that an accurate statement?

Jon Strawn: Pat, you have --I think you may have just answered that question for us.

M: Bill?

Bill: Yeah, it doesn't have to have holes in the pipe. It's going to show areas that would fail based on the rupture capacity of the reduced wall thickness. It will also show cracks that are approaching or a path or a point where they no longer can hold the pipe together at this elevation pressure. So it does eliminate some flaws. The cost of that elimination is that you have destructively tested your pipe at those weakening points.

M: Okay. Last question from this questioner. Does DOT have any plans to move away from enforcing hydrotesting as a stand alone assessment tool?

Jon Strawn: I don't know. I haven't seen anything that would indicate to me that we can look at it as an option. That's probably going to remain a viable option as long as some of the pipelines are not piggable and as long as no other technology is coming out there that I can see in the future--that's going to be a viable option.

Mark Olson: Maybe this is a bit of a follow-up question, but don't the pipeline operators kind of have to justify why they choose one assessment technique over another for the pipeline? So you guys are looking at that, right?

Jon Strawn: Yes. We are looking for justifications as to what assessment technique you are using and why. From my experience of inspecting, as I say, there are some operators in Alaska with production site intensity. Their reasoning is that we can't--they can't pig their line. An example, some of the Cook Inlet pipelines that have a lot--at the base of the drilling platforms they have a lot of manifolding systems in there--a lot of pipelines coming in, a lot of sharp elbows in there. And I think a couple pipe operators can't pig that section of the lines so they're hydrotesting.

M: Okay. Any other comments from the panel? Okay. How does DOT work with local regulatory agencies such as ADEC or AOGCC to ensure regulatory "expectations" are consistent? A philosophical answer will suffice.

Jon Strawn: Well, we coordinate with the state agencies, run through the joint pipeline office, of course. And just as when some issue comes up where we need to work with them, but we do have our federal regulations and we enforce those standards. And the state agencies at least don't have the certificate, they would come up with their own standards--may or may not be consistent with our regulations and in some cases they are not consistent with our regulations and in some cases they are more stringent requirements than our regulations. But I know that the lower 48 that have certificates with the federal government, they do write more stringent standards than the minimum federal safety standards that are out there. In the past, at least since '94 that I've been here, I just work with it--with those state agencies. We just make it happen.

M: AOGCC, do you have anything to add?

Tom Maunder: Representative of AOGCC): AOGCC doesn't go that far; we do not go beyond the well head.).

M: Okay. ADEC? Sam, anything to add? Okay. All right. Next question. Are there situations or circumstances where a five-year inspection pig cycle is not required?

Jon Strawn: Where a five-year pig cycle would not be required? I don't know. I know that I think within 270 days, I believe it is, of that five-year interval that's out there, that if you're not going to make that five-year interval, you have to contact us and let us know why that's not going to be satisfactory. I wouldn't quote circumstances that would push it beyond the five years.

M: Anybody have any comments on the industry side? The experience? Okay. Is there a risk-based methodology that can be used for determining frequency of in-line inspections?

Jon Strawn: Well, it's all risk-based. In my opinion, it's a risk-base and that you either conduct integrity assessments and reassess every five years--at least every five years--or if the risk assessment would show that you have to do it oftener, when you could have a continual assessment and it shows you have to do it oftener, then you would have to do it oftener, I believe. I think Alyeska is a prime example of that when they were concerned about the internal corrosion. There with BP coming down the trans-Alaska pipeline, I think they ran a pig in '04 and they turned right around and ran it again in '05. They just completed it. Dave, is that correct? Or '06. Yeah, they ran in '04 and then '06. Because they were concerned about the effect of the solids coming down the trans-Alaska pipeline. So I think that's a case where they would say that they would have to assess their pipeline oftener than every five years. But you can't go past--I don't see any reason why you'd go past five years. Anybody else?

M: Any comments from the industry panel?

Greg Swank: To carry on with the Alyeska description, if some of you were here during the 8.9 earthquake, Alyeska soon after had some inputs to say--"You know what? Our pipe experienced a little bit of a shock." So they ran a caliper tool, understanding what the integrity of the pipeline was there. So it is risk-based. You take all the data that you have, all the information, analyze that and run tools appropriate to that information and data. They didn't keep to a regular cycle--it's definitely an irregular cycle.

M: Any other comments? Okay. Next question. When do pipeline operators with less than 500 miles of pipeline need to have a baseline assessment completed? There are two parts to the question. On 50% of the HCA lines and on 100% of the lines?

Jon Strawn: When all else fails, read the code book. Did you say less than 500 miles?

M: Less than.

Jon Strawn: Less than--so that would be category 2, so it would be February 17, 2009 you would have to have 100% of your pipeline that affect HCA's integrity tested.

M: Is there a deadline for 50% of the lines?

Jon Strawn: Yes. August 16, 2005. So hopefully all that's been done for category 2 pipelines.

M: Since you went to the book, I assume nobody has got any comments on that. Okay? What method of pipeline integrity inspection do you recommend to be most effective and why?

Jon Strawn: What type of pipeline assessment----

M: Integrity inspection--do you recommend to be most effective and why?

Jon Strawn: Wow. Bill's the pigging expert, but I can try to jump in and say run an MFL with a deformation tool--combo MFL and deformation tool. Why? I believe MFL is probably the best tool of identifying--and I know you may not be able to do this, but it's probably the best at measuring top of pipe dents with metal loss.

M: I suspect we'll have comments from other members of the panel?

Frank Sanders: I would say that the best person to address what's the best ILI tool for your pipeline is not any of the experts up here, but the experts who run the pipeline every day and know their pipeline. That's the ones that determine what is the best ILI tool to run.

M: More comments?

Jon Strawn: And we certainly don't dictate which pigging program--what your pigging program's going to look like.

M: Other comments from the panel? Pat?

Pat Vieth: I think the question was not even specific to in-line inspection, but what integrity assessment methods?

M: Integrity inspection.

Pat Vieth: Integrity inspection? Well, the answer is truly, "It depends." It's understanding the integrity and threat and designing the program around that data. So that's kind of what we focused on several times throughout these discussions. So the answer is, "It depends."

M: Okay.

Jon Strawn: But you're also--I'm basing my answer on what has been done. And if you looked at that chart that I had today, the deformation tool and MFL is by far and away the best--at least the operators' pigging program of choice.

M: Okay. Any other comments? Okay. I just have a couple more minutes. I know we're going to run out of time than questions first here. But we're going to do our best to get the last couple here. Why are not more process and gathering lines DOT regulated when on the surface they appear to fall under the scope of 49CFR, part 195.

Jon Strawn: Well, I'm not sure I got the question. Why are not more pipelines regulated?

M: Why are not more process and gathering lines DOT regulated when on the surface they appear to fall under the scope of 49CFR, part 195?

Jon Strawn: Okay, gathering lines do not fall under the scope of 195. The transmission lines fall under the scope. We don't regulate flow lines, gathering lines, three phase lines, etc. They're exempt from the code. We have jurisdiction over all of the pipelines, but we don't have regulations established for certain types of pipelines. Did that answer the question?

M: I think it answers the question. I guess the questioner would probably say, "Why not?" Why are these other pipelines not regulated?

Jon Strawn: You'd have to ask the Admiral about that, I don't know. I'm just the bottom-feeder here in Alaska.

M: That was the Admiral walking around upstairs. Okay. Second to the last question. MFL tools and other ICI tools can experience "technical difficulties" which result in less than 100% data capture. What are DOT standards for data capture to certify an ICI run? Are these standards published and recognized?

Jon Strawn: We don't have a standard for them. We hold the operator accountable for the development of those standards, for having procedures and processes in place to make sure that your--that you've got adequate people evaluating the pigs, that you have a pig acceptance criteria established, on and on and on. But it's up to the operator to come up with those standards. I don't know of any standard in the code.

M: Okay. Anyone else have anything to add to that? Yes, please, Jon.

Jon Wharf: I guess what we're looking at in the case of an incomplete data collection is any inspection is aiming to reduce the unknown risks to your pipeline. If you have incomplete data, then you haven't reduced your risk quite so much. Then you should just be addressing those risk areas in the rest of your plan, I guess. If you can't for some reason pig for improved inspection coverage.

Jon Strawn: And again I think that looking at that paragraph in the code would indicate what our expectation would be from an integrity standpoint. It's up to the operator to determine if they can meet that standard.

M: Other comments on this?

Greg SwanK: There is API, an RP, recommended practice 1163 that speaks to percentage of data gathered and what you need to do to evaluate your data and what you need to do to run pigs again. It's also covered under an ISO standard for the international community.

M: Okay. Jon, believe it or not, we've run out of time.

Sam Saengsudham: One more. I think this analysis to me is a standard of pigging.

M: Okay. Thank you very much, Jon. Appreciate that. We had one more question for Jon and if we have time at the end, I'll ask it. Okay? I just want to make sure we leave enough time for the other people who have questions directed at them.

M: Okay. Jon, as if you haven't had enough questions, here's one more for you. Regulations--and I think this is ISO, maybe 150--has a certification program. Why does DOT office of pipeline safety not have a similar program so that operators are sure their programs are in compliance with the regulations?

Jon Strawn: We don't dictate the training program, we have an operator qualification rule that you have to meet a four-part test and you have to demonstrate to us that your operators are qualified to be in the job. But that would be left up to the operators as to what standard and how they're going to qualify their operators. We would not get involved in that. Greg, you were talking about that a little while ago.

Greg Swank: I think we heard a mix of things here. We're talking about OQ in this particular response to this question. And I'm not certain that question was regarding an OQ response. It sounds to me like they were talking about a certification of programs being met to the regulatory requirements through an ISO standard. I can't answer why DOT does not require a similar ISO standard in the U.S. And I'm not familiar with that ISO standard to be knowledgeable enough to comment.

Jon Strawn: It seems to be that I'm not familiar with that ISO standard.

M: Okay.

APPENDIX J

INTELLIGENT PIGGING CONFERENCE PRESENTATION 5

PIGGING THE UNPIGGABLE

MARK OLSON OF TRINITY PIPELINE ASSESSMENTS, L.L.C.

ABSTRACT OF PRESENTATION 5

Pigging the Unpiggable

Speaker Name: Mark Olson, President and CEO

Company Name: Trinity Pipeline Assessments, L.L.C.

Type of Business: Trinity Pipeline Assessments (TPA) is the commercializer of the Explorer II(TM) and TIGRE(TM) robotic In-Line Inspection (ILI) systems and consists of a pipeline engineering consulting firm and a pipeline construction company with a specialization in pipeline integrity services (including Direct Assessment, hydrotesting, and ILI support).

Mark Olson provides a brief background on the varying degrees of "unpiggable" and discusses the "state of the art" in regards to ILI technologies currently available or nearly available for these "unpiggable" applications. In addition to the overview presented, the paper details the capabilities of a tethered MFL technology which has been used to inspect "unpiggable" pipelines since the mid-1980's and the capabilities of some exciting new robotic technologies. Topics of discussion include:

- Recent and near future advances in pigging tools and techniques to perform in-line inspections of pipelines lacking pig launchers and/or receivers;
- Pigging tools and techniques to traverse pipelines with severe inside diameter reductions;
- Tethered tools;
- Small and larger diameter crawler pigs;
- Robotics.

TRANSCRIPT OF PRESENTATION 5

M: Our last presentation of the morning, presentation number five, is by Mark Olson. Mark is with Trinity Pipeline Assessments and will talk about "Pigging the Unpiggable." Sounds like a movie script. "Pigging the Unpiggable." This stuff is funny, come on now.

Mark is a mechanical engineer with more than 15 years of experience in design, maintenance and operation of pipelines with a specialization in pipeline integrity. He has personally managed several thousand miles of pipeline cleaning, in-line inspection and rehabilitation activities.

Mark is a former manager of Baker Hughes Pipeline Management Group's tethered and free swimming in-line inspection businesses.

You are on the hook. Thirty minutes with ten minutes of questions. Thanks.

Mark Olson: Thank you. One of the worst things about giving a presentation is having your resume read in public. But one thing that was left out that I want to point out. Back when former Senator Al Gore invented the internet, my name got shortened from Mark Olson to Molson, so--- It's easy to remember.

Before getting too deep into this subject--what do we mean by unpiggable? Is a pipeline unpiggable because it's never been pigged before? Is it unpiggable because it has no launching and receiving facilities, or because it has multiple diameter changes? Low pressure, low conditions where there is not enough differential pressure to propel the self-propelled pigs? Or is the pipeline constrained by certain features that the tools just can't navigate? Or some combination therein.

The premise of my presentation here, a lot of us in here are engineers and we're "can do" kind of people. And I believe that there are in-line inspection techniques for just about every combination of these unpiggable pipelines. So, I'm going to discuss several that I'm familiar with and I'm probably even missing some. And for that I apologize, but----

Just, I guess, a picture's worth a thousand words. This picture is not necessarily a realistic pipeline, but it kind of shows graphically lots of different pipeline features that would be considered unpiggable. Let's see if I can do this without advancing the slide.

If we're trying to inspect this light blue pipeline, right off the bat, you come into these mitered bends, and traditional free-swimming pipeline tools wouldn't be able to traverse those. And then you come to a plug valve, well, first of all fairly significant diameter change and then a plug valve that's even further restricted. And let me just say that plug valves are one of the more challenging features. For example, a 20 inch plug valve--the opening that the tool has to go through is 6-1/2 inches wide by 14 inches tall. So, it's quite a bore restriction.

Continuing on down the pipeline we come to a 90 degree miter bend. And now this isn't a point-to-point pipeline, this is a network of pipelines maybe more similar to a production field or a local distribution gas company. You know, if we want to inspect this branch, a traditional free swimming smart pig wouldn't be able to turn the corner and inspect this branch and then come back and come down to this dead leg and then come back.

Here as we go in here on the network there is a very large--I guess a change in diameter. And then another branch connection and another valve and continue on. So, I wanted to show graphically what we're talking about when we're talking about constraints to in-line inspection.

Multi-diameter pipelines. I don't want to spend a lot of time on this. Pretty much all of the major in-line inspection companies have full ranges of multi-diameter tools ranging from pipelines starting as small as six inch and 56 inch and above--the whole range of tools. I just want to grab three bullet points and put them up on the board as far as fairly significant inspections in history that I've either been aware of or been impressed by or been involved with myself.

One of the more famous tools is the 28 by 42 inch multi-diameter tool by GE PII. Long, offshore pipeline--or long pipeline, it's onshore and offshore. Between 28 and 42 inches it telescopes up in size and down in size and back up in size several times, so truly a broad range and quite a technological challenge.

The last two projects I was involved with a 25 kilometer pipeline in Toronto with five reduced port valves. They use a 30 inch pipeline with 23 inch valves and there was no transition. I mean the pipeline just slammed from 30 inches right into a 23-inch opening and the CPIG was able to make some minor modifications to their off-the-shelf 30 inch tool and navigate that pipeline. And what I'm trying to say is the technology for multi-diameter pipeline inspections is quite good.

Another project that I was involved with was a 6 by 8 dual diameter pipeline, back to back 1-1/2 deep bends, several user fittings that were not known to the client or to us, and the tool in the 6 inch pipe and traversing numerous fittings. The point is really that all the major inspection companies out there have pretty good tools these days.

This is a product line which I was responsible for several years. The Baker Hughes Pipeline Management Group's feed line. This is some down hole technology that is being applied in unpiggable type applications for over 20 years now, mostly in oil field type situations, flow line, production fields, transit lines.

This slide--the upper picture shows a dual ended access with waterline trucks on both sides. How they rig up--they'll put a foam pig and the cable in one end and then aero-nitrogen--the pipeline has to be out of service. It will blow the cable over to the other truck, then they'll attach the tool and they can actually yo-yo the tool back and forth through the pipeline and repeat the inspection several times if need be, or if there is an interesting feature you can back up and go over it again.

The bottom picture is just a single-ended where the tool and the cup pig are loaded into the pipeline and again with aero-nitrogen the tool is pushed out into the line and then reeled back in.

Some of the advantages of this, I guess the main disadvantage is the line has to be out of service, but that can also be an advantage with the real time data and the immediate feedback. You can repair the pipeline right while the inspection equipment is on site.

No launcher and receiver. The solution required is an offline inspection. Hydrosolution data--I'm going to show a slide. Several of the tools are older coil--induction coil technology and everybody likes to turn their nose up at induction coil technology and call it low risk, but the reason why induction coil technology may be low risk is it's very sensitive to speed of the pipeline. In this application with the tool being deployed on a wire line, the speed variable is completely controlled and the results are quite good.

Repeatability. The tools--they are metal loss tools and MFL technology. ID., OD. with differentiations is also available. The big advantage of the technology is the repeatability. You can repeat the inspection several times while you are there.

Real time data, same day repair, and a tethered operation--so you have physical control of the tool all the time. A logical question is what's the longest that you can inspect in one location and that's about six miles. I shouldn't even throw a number out there because it really varies depending on the mission profile. It's a function of the number of bends and the tightness of the bends and the diameter of the pipe and several things, so--but six miles is possible basically from one location. You can go out one way three miles and out the other way three miles. And different people say seven miles, some people say four. But I know that six miles is a safe number.

I also want to point out that this is a pretty cost effective inspection technology. Because the application is short runs and lends itself to oil field applications, you can go out with a truck and a tool and a crew and inspect a whole network in a matter of a week or a couple of weeks and the per foot price when you do multiple inspections in one mobilization is pretty beneficial.

This is just the size range that's available. I don't want to spend any time on this chart, obviously. But you can see there's quite a range of tools from 2 inch to 32 inch available. There is a mixture of hall effect MFL technology and coil technology. The wall thickness range is very standard for MFL tools. I would say that 95 to 99 percentile of your pipelines fit in that range.

The bend capability of the tools ranges from 15 D for the smallest tools to 1-1/2 times the pipe diameter for the larger tools. The detection thresholds and the depth sizing accuracy and the length sizing accuracy you can see are fairly high resolution sizing accuracies. The hall effect technology being plus or minus 10 percent of the wall thickness and the induction coil being plus or minus 15 percent of the wall thickness.

This RSS system is a system that Rosen is constructing right now. They've got funding and a project for this. This is a thick--they are building it for 10 inch and 12 inch applications currently and would be happy to build more pipe sizes if more money was available. This is a good concept for low flow conditions. This can be launched from a launcher or some kind of temporary launcher through a flange or something. It has a range of several thousand feet and it's self-driving such that if there's insufficient pressure to drive a traditional smart pig, the tracker can drive it into another pipeline.

I guess I'm kind of progressing to more and more challenging pipelines to inspect. What I am looking at here is the pipelines that have physical features that would prevent inspection. This picture here might be a little dark to see. This is a pig's eye view of a plug valve. So I think this particular picture is a 30 inch plug valve, and that's the window that the tool has to navigate. I kind of--I am inventing terminology here, but I have been calling this class of unpiggable features tight feature constraint. And you can either bypass it or you can find some way to navigate it and this is a system developed by GE, I believe. It's currently available only in 20 through 26 inch sizes. But they have developed with their multi-diameter capabilities for their pipelines and with this special chute that they've developed to be deployed through a hot tap fitting you can put hot taps on either side of whatever feature you need to bypass, and navigate the feature by bypass--you can bypass the feature and inspect the pipeline with a more traditional smart pig.

This leads us to the last subject that I want to talk about and spend a little time with is robotics. Robots--there have been prototype robots and R&D programs related to pipeline inspection robots going back to the early '90's. GE and Foster Miller combined on some of the earlier developments. The first tool was called pipe mouse. And then in late 1999-2000 the Northeast Gas Association and the Department of Energy got together and funded some additional research. They funded two parallel path projects: one with the next generation Foster Miller/GE tool called Roboscan, and then the other one was Explorer. And that was primarily developed by Carnegie Mellon University in Pittsburgh.

At some point, I think around June of 2004, the two systems came to field trials and the Explorer system was chosen for further development and further funding. And that's continued on. In June of 2004 the Explorer robot which is simply a video inspection robot, it's the first generation robot, was just for video inspection launched and received through a hot tap fitting into a live pipeline, it can crawl around in the network and come back out through the same hot tap fitting. And this was developed for inspecting cast iron and steel and plastic for that matter distribution piping in the gas networks.

I have a quick video here of the tool actually launching and crawling around in the pipeline. The tool is actually entering the pipe right now and you can see right here the nose turning down into the pipeline out of the launching pit. I believe those are actually shavings from the hot tap fitting in the pipe. That right there is what was another tap that was put on the pipeline while it inserted the antenna for the wireless communication. This is the tool turning to go into a side T. So that's the side T right there. That's the nose of the tool turning into it. Now we're coming back out of the pipeline.

Explorer II then is the next generation. Basically Trinity Pipeline Assessments has been selected as the commercialization partner for the Explorer II robot as well as the Tigre robotic system that has been funded and developed by the Northeast Gas Association.

Explorer II is really just the next generation of the tool that we just saw the video of deploying sensing technology to be able to assess the pipeline more than just video. So, the picture here is a remote field eddy current sensing technology that is being developed by the Southwest Research Institute and which we're licensing for the tool. So, we'll also have high resolution MFL sensing sections available to deploy on this tool with internal/external discrimination and caliper sensors as well.

So, again, the highlights--launch and receive through a single hot tap fitting into a live pipeline with the Explorer II platform will have 6 inch through 14 inch capability by late summer 2007. Remote field eddy current or high res MFL sensing section available video metal loss, audio in caliper data sets. Completely autonomous meaning it's not tethered, it's a completely autonomous robot using wireless communication and real time data feed back above ground to the operator. And this tool design criteria--in this size range the design criteria is to navigate miter bends, branch connections but not plug valves. The opening of a 6 inch plug valve is just a packaging process.

Just to get a sense of the schedule, our live platform is complete right now. The platform and sensing section will be integrated at the end of February 2007. We will be doing field trials. We're working through the integration issues and doing a lot of in-house testing March, April, May with field trials scheduled for May. And as part of field trials and doing lots of demonstration runs gathering enough data for our API1163 qualification. And we plan to have these tools commercial by mid-summer of 2007.

Tigre is another robotic platform. It is probably also a second generation of the original Explorer tool, but the major difference is it's large diameter. So, the 16 through 36 inch tools will be the Tigre platform. And it's designed to navigate plug valves. So all of the vessels and bodies have to be small enough to fit through the opening of a plug valve and it uses high resolution MFL magnetizer section, so that magnetizer section has to be able to collapse, be pulled away from the pipeline and also pass through a plug valve.

Another interesting feature on this is also it integrates a turbine for in-line recharging of the batteries to extend the mission.

Again, launch and receive through a single hot tap fitting throughout the pipeline that 20 to 26 inch capability will be late summer of 2007. High resolution, hall effect MFL sensors, again will be video metal loss, i.d., o.d. and caliper data sends. Again, completely autonomous wireless communication and streaming data, video and be able to access. Onboard power generation, and the design criteria is to navigate miter bends and branch connections as well as plug valves.

Commercialization schedule for this platform--robotic platform is being assembled right now. And the sensing section is complete. The platform and sensing integrations start right after the holidays. Field trial is in May and, again, between January and May that is a lot of the in-house testing and the data that we gather May, June, July will all go toward the API1163 qualification and we expect to be commercial with the 20 through 26 inch size range late August or early September.

This here is a concept for a robot by Rosen. My understanding is this product is not funded yet. And they are very interested in partnering up with various operators so if that's something you're interested in participating in, there's some contacts. So I've got contact information at the end of the presentation.

But conceptually in launch receipt through single hot tap into live pipeline, I anticipate the first prototype available late 2008 or early 2009. EMAT or eddy current sensing with infrared 3D imaging and inertia mapping capability. Fully autonomous operation and, again, wireless communication. Real time data. Onboard power generation and the ability to navigate miter bends, plug valves and branch connections.

In conclusion, I just want to stress that I believe that ILI techniques are available for your pigging unpiggable locations. Again, I kind of wanted to summarize where to go for the various applications and it's really important to match technologies to the applications. And every pipeline is going to have a different mission profile.

And as my presentation is really concluded, we can go to questions if you like. I wanted to leave this up there for the note takers. Just contact information for the various people at the various companies with more information on applications for your current assessment projects.

M: Thank you, Mr. Molson.

TRANSCRIPT OF QUESTIONS FROM PANEL

All right, we have ten minutes of questions. Any questions from the panel?

Greg Swank from BP: Mark, one question--it certainly looks like it's capable to introduce a pig into the line through a hot tap if you don't have launcher and receivers. The questions, two I've got: (1) how big does that hot tap have to be? Is it a one-to-one to the size of the pipe you are running? And (2) can you also use an operating pipeline system with a tethered pig?

Mark Olson: I will address the first question first. The size of the hot tap fitting needs to be at least as large as the smallest size of the tool. So, the one tool is covered in many different sizes. For example, the smallest tool is good for 6 and 8 inch pipelines. It has to be multi-diameter, so if it was an 8 inch pipeline you would need a 6 inch hot tap. If it was a 6 inch pipeline, you need a 6 inch hot tap. On the larger diameter tool a 20 to 26 inch, again, you would need a 20 inch hot tap if you were inspecting a 24 inch pipeline and you'd need a 20 inch hot tap if you were expecting a 20 inch pipeline.

On your tethered question, are you referring to tethered technology like a feed line, or are you talking about a tethered robot?

Greg Swank: Most likely the tethered V line. Something that would give you MFL data or some kind of data back from corrosion and not have to shut the line down.

Mark Olson: Yeah. With the V line technology currently the line needs to be out of service. I believe they're actually working on the ability to run it online, but I am unaware of the progress there, but Terry Wheeler is actually here today and in the booth. Sorry, Terry.

Bill Flanders: Has any thought been for robotics in slack line areas in liquid lines where the velocity of the fluid is so high that it a normal MFL or UT tool couldn't get accurate readings?

Mark Olson: In a slack line, you mean kind of like low flow?

Bill Flanders: High flow, over amount fast.

Mark Olson: To my knowledge, the current robotic platforms are really looking at an out-of-service line as far as the liquids go. So, there's more R&D going into basically the navigation and the communication on the robotics in order to be able to navigate liquid lines. It's still a pretty new field.

M: Does that answer your question? Other questions from the panel? Yes, please.

Tom Maunder, Oil and Gas Commission: On your tethered systems, is the wire line coated or are precautions taken to avoid any sawing effect as you go around features?

Mark Olson: The wire line and the pipe is lubricated as part of the process. So, the wire--it's a standard down hole style wire line, so not coated as such. In 20 plus years of running the technology, I have only heard of one instance of sawing and basically what we're talking about is where the cable drag actually physically damages the inside of the pipe. And my understanding of the situation was that they were navigating too many bends, or whatever, but the operation just put in too much line for the cable. And that part of the mission profile has to be defined. But in 20-plus year history, I have known of only one instance of that.

M: Does that answer your question? Other questions from the panel? Yes, please.

Chris Dash, ConocoPhillips: A follow-up to that question, how many bends is too many bends? We have expansion loops on the Slope that----

Mark Olson: Well, there's a rule of thumb and I think it's 720 degrees and--my mind just went blank, Terry---- What that means, 720 degrees is, you know, a 90 degree, plus 90 degree, plus 45 plus 30 equals quick. So, but again it is in the mission profile. And you really have to with tether application, really do have to take a look at the mission profile because you can inspect pipeline at the branch connection, right? You can choose where to make a cut. If you're not accessing the line through an existing flange you can choose where to make your cut, so you can make your cut at a T and go in three different directions. Inspect with a wire line from three different directions and now your number of bends is 720 degrees times three different inspections from one cut and one inspection. It is the multiplication of the wire.

That's where the engineering and project management and strategy and coordination with the operator come in.

M: Does that answer your question? Other questions from the panel? Yes, please.

Sam Saengsudham, ADEC: Mark, what is the inspection speed for this Explorer II and Tigre?

Mark Olson: Four inches per second.

M: Does that answer your question? Okay, other questions?

Mark Olson: We can go faster or slower, it's a design compromise. It has an effect on battery and how long it takes to inspect. We can go slower and have more battery life, but it takes longer to get an inspection. Or we can go faster but it goes through batteries quicker.

Sam Saengsudham: What is the fastest it can go, then?

Mark Olson: That's a good question. Eight inches per--or four inches per second works out to a couple of miles per day. And just shooting from the hip, I would say that double that speed is probably an upper limit.

M: Does that answer your question? Other questions from the panel?

We had more questions for Mr. Molson than for anybody else. That's good. Appreciate it. Thank you very much.

All right, it's now time for lunch and, once again, what time are we supposed to be back? 1:05 right on the dot. Thank you.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

So, the next person on the line here is Mr. Molson. Mark Olson. And you'll remember that Mark talked about pigging the unpiggable. And he had a film to boot. Okay? So----

Mark Olson: I'd like to start off by yielding five minutes to the gentleman on my left.

Jon Strawn: See you in court.

M: Okay. I'm supposed to be the comedian.

Mark Olson: I was serious.

M: Okay. First question. Please answer this one in Greek. No. Please explain the potential future use of a portable pig launcher and receiver you helped design in 1990's for North Slope pipelines.

Mark Olson: I don't remember designing a pig launcher.

M: Actually, this has Lou's name on it. Is this something that you would have a hand in? Okay. Then let's have you get it. I'm sorry, it had number five on here, but it's directed to Louis. Should I repeat the question?

Louis Kozisek: Maybe shuffle it off to someone else. I haven't been involved in the Kuparuk corrosion program for probably a dozen years, so perhaps Chris Dash could answer that better than I.

Chris Dash: Could you read the question, please?

M: Okay. Please explain the potential future use of the portable pig launcher and receiver--you didn't help design it--but that was designed in the 1990's for North Slope operations.

Chris Dash: We are currently using it on our 20 inch pipeline for maintenance pigging, and we are probably going to use it for maintenance pigging and smart pigging in 24 inch line. So, we will use it.

M: Mark, I think this is actually a question for you this time. For robots, how far can they travel?

Mark Olson: That's a good question. And it goes back to all the engineering and project management that needs to go into every mission profile. The batteries on the tools range up to 24 hours, so figure roughly six, seven miles in a network.

Now the larger diameter tools have got a turbine so that overnight they can just sit in the pipeline and recharge with the flow over it if we're talking about in a gasline. But the tools, just based on the network and the mission and where it's convenient to put the tool in and out of, you take a tool out of another hot tap downstream, replace the batteries and put it right back in and go again, or you can crawl all the way back to the original entry point and change--refresh the batteries and go back out again.

And some of the ongoing research that we're working on is to actually be able to access the pig through a small tap in a line and plug into it and recharge it where it is and continue to extend the mission. And another interesting design feature is the tools are very modular, so we can add more battery sections and more drive sections and extend the mission that way. But at the speeds they run, they're not intended to be designed for cross-country pipelines.

In doing some market research, one potential customer I was talking to was very excited. He had a 100 mile pipe that wasn't unpiggable and they had plug valves on it. And I'm like, you can pay my crews for 50 days, I'd be happy to come and inspect your line but there's probably more cost effective ways to do it and maybe they--in their integrity management program maybe they just want to look at HCA's and then we'll point a tool in and taking it out based on the boundaries of the HCA's.

M: Okay. This actually is the second part of this individual's question. Does the production need to be shut down during this operation?

Mark Olson: Yeah, the current status of the R&D--the tools, and maybe I didn't go into sufficient detail. The tools first of all--you've got video cameras and headlights--I guess taillights. You've got headlights on both ends of the tool, so one of the very important data streams that are coming in for just navigating a pipeline is the video feed. So that you can always see where the position of the tool and see what obstacle you're coming into.

So for video purposes, being in a medium that you can visually see with the video is important. And also the control system--the ability to talk to the tool and issue commands and get position and status from all of the different servo motors and everything. That's all communicated wirelessly inside the pipe to antenna or whatever. And the video feed is coming over the wireless and the data stream--all the data streams are coming over the wireless. So that necessitates a gas or air, natural gas, or whatever.

So due to the navigational and control needs of the current embodiment, the flow line needs to be drained up. We are--the ongoing research is to overcome those obstacles--navigation and control in order to be able to run live online in a fluid environment, even including crude oil non-clear medium.

M: Any other comments from the panel? Okay. Next question. Can the Explorer take video in a liquid pipeline or does it need to be shut down?

Mark Olson: I think I just answered that. It needs to be drained up.

M: Okay. Please discuss portable launchers and receivers versus hot taps. Here's the question. Please discuss portable launchers and receivers versus hot taps.

Mark Olson: Well, if you can access the pipeline just by bolting up a portable, a simplified portable launcher, just a tube with a flange on one end and a blind flange on the other end--if there is an access point, just a valve or a flange that we can break in and flange up to, that's real easy.

And, again, every project is different and the project engineering that goes into it developed in the mission profile, we would definitely look at the most cost effective way to get in and out of the pipeline. Otherwise, the system is designed for the worst case, which is a hot tap ingress and egress.

M: Okay. Any other comments from the panel? Please.

Sam Saegnsudham: You were saying, the Explorer the line needed to be drained out, that is including the Explorer II that use MFL?

Mark Olson: I didn't hear the first part of the question.

Sam Saegnsudham: The Explorer II video tool you have right now using the MFL technology, right?

Mark Olson: Correct.

Sam Saegnsudham: Does that also require the line be drained out?

Mark Olson: Correct. Tigre and Explorer II and Explorer- all of them. Even the predecessors to those, I'm not sure what the Rosen's plan is for the long-term. It's an issue they're going to have to deal with.

M: Yes, please.

Chris Dash: One thing to be careful about--hot tapping is inherently risky so it's much better to use flanges that are already there in available spots than it is to hot tap them in.

Mark Olson: I would agree 100%.

M: Other comments? Okay. With respect to liquid packed pipelines, specifically crude oil packed, at what stage of development are robotic inspection devices, and do you have any projections in terms of when they'll be online?

Mark Olson: Yeah. I think--I'm shooting from the hip. It's based on my experience and the question is who pays for it. The funding and the ongoing research is really typically pretty slow. And it's not until it gets closer to commercialization that the pace really picks up. And then someone like myself can get involved. But I would, if I were to hazard a guess, I would say 2, 3, 4 years. Just making that next step is probably on that order of magnitude.

M: Okay. Any other comment from the----? All right. Do you need to de-inventory the line when intervening with tethered or other ILI tools?

Mark Olson: My understanding is with a tethered system like the Baker Hughes V line technology definitely the line needs to be de-inventoried, or drained up, if you will. And I failed to mention in my program that pretty much all of the traditional--I say traditional--free-swimming pigging products can also be used and have been used in somewhat of a tethered format. I know Rosen has done it frequently and C Pig as well. And I assume that GE and Tuboscope and Magpie have as well. And to my knowledge those would all be evacuated.

It was also brought to my attention that A. Hak has a tethered technology that looks fairly interesting. I'm not as familiar with it and have no personal experience with it. But that can actually run live in product. It's worth looking at earlier--and here, they're actually here.

M: Okay. Last question. Are there ILI tools that handle an expander in the line? For example, like going from six inch to eight inch, say in the direction of the flow.

Mark Olson: Yeah. That's what I was referring to when I talked about multi-diameter pipelines and multi-diameter tools. The more traditional free-swimming tools, all of the companies have a broad range of multi-diameter tools where--and by multi-diameter I mean they might be telescoping up a couple of sizes and down a couple of sizes throughout the inspection and the tools can handle pretty significant pipe changes. And that's probably--we've seen a lot of advancements in that just over the course of the last two or three years.

M: Any other comments from the panelists? Thank you, Mark.

Mark Olson: One thing I just wanted to say if I get a free second here. It sounds like a lot of the questions and a lot of the answers were all dancing around a common theme. And somebody actually said earlier. But the IMP rule--the integrity management rules--are not pigging rules.

And I always want to keep things in that perspective. It is an information gathering rule, it's an information management rule, decision-making, continual improvement. But it's not a pigging rule. I wanted to do my comment on about 10 or 15 of the questions that were asked, but I just didn't say anything.

M: I'm glad you didn't.

Mark Olson: I've got four already.

M: Let me just make it real clear. A lot of the people in the audience are looking for information. That doesn't mean that every questioner is as aware of these things as you are. So thank you.

Mark Olson: Yeah, I'm just trying to put it in kind of a big picture context. You're always looking at the questions and answers from the integrity management rules, and from that perspective it is easy to get sucked on into the minutiae and you really want to keep your--keep that big picture focus in it as well.

M: Okay. Once again, thank you, Mark.

APPENDIX K

INTELLIGENT PIGGING CONFERENCE PRESENTATION 6

IN-LINE INSPECTION ON THE NORTH SLOPE

GREG SWANK OF BP EXPLORATION (ALASKA), INC.

ABSTRACT OF PRESENTATION 6

In-Line Inspection on the North Slope

Speaker Name: Greg Swank

Company Name: BP Exploration (Alaska) Inc.

Website URL: **www.bp.com**

Type of Business: From a pioneer explorer in Alaska in the late 1950s, BP has become the largest oil and gas producer and one of the largest gasoline retailers in the US. BP is the second-largest liquids pipeline company in the US, operating about 10,000 miles of pipelines, and is the second-largest refiner and the second-largest fuels marketer in North America.

A comprehensive Integrity Management Program (IMP) goes beyond proving pipe integrity; it analyzes the risks associated with the pipeline and evaluates the appropriate actions necessary to reduce those risks. Performing In-Line-Inspection (ILI) by running appropriate inspection tools is one method of evaluating pipeline integrity. ILI results are validated and than analyzed utilizing a variety of engineering tools to determine the pipeline's integrity. The comprehensive risk assessment than evaluates data related to the pipeline design, operation, maintenance, leak history, and environmental conditions. This data evaluation calls for a management system that is able to store, retrieve, and integrate the information. While this appears to be an easy task it is not. Most data is scattered throughout the records system and utilizes a variety of documentation techniques. This presentation will provide an overview of a comprehensive IMP and than focus on the risk assessment that is integral to complete the program. This presentation will also discuss the latest developments in the following areas:

- Goals;
- Limitations;
- Frequencies;
- Types of Pigs;
- Performance Management.

TRANSCRIPT OF PRESENTATION 6

M: Our last presentation is by Greg Swank. Everybody knows Greg. I think he set the record this morning for the most questions. You get two guesses to guess what the official colors are of Ohio State University. Scarlet and gray. I think Greg is going to wear that until they lose, so we may get tired of that sweater before the end of the year. Okay, Greg, once again, is with BP. He is going to discuss in-line inspection, ILI, on the North Slope. Greg is the manager of regulatory and technical services for BP Pipelines. He has over 25 years of experience in the oil and gas industry performing engineering, construction, operations, and government oversight activities. Greg has worked periodically on the North Slope since 1975. He is, as I have already mentioned, a graduate of Ohio State University in welding engineering, is a registered professional engineer and spent two years as an associate professor.

Okay. Thirty minutes.

Greg Swank: Thank you very much. Good afternoon. Hopefully, everyone had a very good lunch and I am going to be in a position to allow you that time to digest, take a little snooze, just relax. So this will be good.

Yes, I am, as Pat said and you heard, from Ohio State, so Saturday between about 11 to 3 I will not be taking phone calls.

I have recently changed positions. I am currently titled the HSSE Advisor. I no longer report through North America Pipelines out of Chicago. I report directly here through the BP--I've got to figure out who's paying me here--BP Pipelines, or BP Exploration Alaska.

So I changed jobs, my past job dealt strictly with the DOT covered pipelines. We are still figuring out what the current role is going to be, but it looks like it's going to be pipeline-related for sure.

Today I'm going to talk to you about BP's integrity management program and how it relates to those covered pipelines with a focus on the risk assessment task associated with the integrity management program.

But first I want to review the progress related to the oil transit lines in Prudhoe Bay. The corrective action order we received from the DOT was mainly about running in-line inspection tools. The Lisburne pipeline was the first in-line inspection tool we ran on the oil transit pipelines. The results came back with no repairs required on that particular line.

The second pipeline we ran an inspection tool through was the 34 inch currently operating what we call the EOA, the eastern operating area pipeline. That in-line inspection tool came back. We're currently validating the tool inspection results, and it certainly appears that there is no internal corrosion that requires repairs on that particular line either.

And today I got the news that we had a successful magnetic flux tool run, ILI run, again in WOA, which is the 34 inch western operating area pipeline. And we certainly don't have any results yet to speak to you about. But we have successfully completed all of our in-line inspection runs on those particular lines.

Just to schematically let you know where these lines are, the first leak in March occurred in this particular segment, which is shut down. The line that we just completed the run in yesterday--or actually--yesterday, I believe--is this section here from the GC1 area over to skip 50 by Alyeska. It goes to Pump Station 1. This is a 16 inch Lisburne pipeline, the LPC line, that we ran the inspection tool with good integrity. And here's where we had the second leak. And then that was a 30-inch pipeline. The-34 inch pipeline, we ran several weeks ago and that particular pipeline looks like it has good integrity.

Okay, so what is integrity management? It's a continuous improvement process. You apply it throughout design/construction/maintenance/operation and in through the commissioning of the pipelines to assure that you manage integrity safely.

Sandy mentioned earlier this morning that all the current DOT regulated light pipelines, Northstar, Endicott, Milne Point, Badami, are going to fall under the DOT integrity management program, and we've made a commitment to Admiral Barrett who is the chief of the PHMSA association there in DC, that we will have that completed by 12/31/06. So that was quite a task to get accomplished.

We are also going to include the low stress pipelines that are not currently regulated by DOT. Those are the OT lines that I just talked about--the Lisburne pipeline and the east and west 34 inch oil transit lines. We will include those in the integrity management program review also.

And to make our task just a little bit tougher, we decided to--BP's a pretty good-sized organization in America, and we had separate programs. BP Alaska had a program, integrity management program, BP North America Pipelines had one, our gas folks have an integrity management program. We had one down in the Gulf of Mexico. We've integrated those into one program, so we are also in the process of transitioning into one integrity management program. So, throw that all together, we've got a little work ahead of us.

Integrity management program: Here's some of the plan contents of a good integrity management program. One: Segment identification. I think Jon went through that quite a bit today, this morning. Baseline assessment plans, what are you going to do to run, basically, your tools. We also have an assessment of those results and any remedial actions as a result of that baseline assessment. Then we perform the risk assessment. The majority of my talk today is going to be on that particular piece, the risk assessment piece. You have to qualify your folks, you need a batch of supporting documents. And then you have to analyze all that information.

As a result of the risk assessment, you have preventive and mitigative measures. You have continuous evaluation assessments and then program measures to see how well your program is functioning, taking any course changes as a result of that.

This is an interesting bubble graph from the BP Pipeline Integrity Management System, PIMS. And you can see the various pieces of the puzzle that make a complete integrity management program in the BP system.

Key risk factors that you need to evaluate while you are performing your integrity management is the proximity of any high consequence areas. There's five of them in three large categories. There's five areas--high pop and other pop, we call them. Drinking water, environmentally sensitive and commercially navigable waterways. So those are the high consequence areas. You also need to understand what kind of product you're pushing inside that pipe. Different products have different risk factors associated with them.

Ruptured volume loss and dispersion potentials: We've conducted some LIDAR surveys in Prudhoe with a little aerial ground overflight photography. We've done some fate and transport analyses to understand where your low-lying grounds are, where your oil if it's spilled, where it might go so you can understand that from a risk perspective.

The time since your last assessments, so you need to understand what all your data is, how much information you have up there to integrate that. Your leak history. Leak history is an element you definitely need to evaluate so it helps you point to where you need to understand how you're going to manage that particular threat.

Operating stress versus design limits as well as any cycle fatigues or pressure changes in your system. Natural hazards: earthquakes, floods, landslides, those kind of things. We've had a heck of a storm up in Prudhoe here about a month or so ago. That particular storm was a very large event in Prudhoe Bay. You need to understand those kinds of events and what effects it may have on your pipeline. And, of course, pipe safety design. Roughly older pipes from the high frequency/low frequency RW welded. We don't have that kind of a problem at Prudhoe Bay, we've got good pipe that's outside of that particular problem from a risk standpoint.

So what do we need to understand? What information do we need to analyze on these risk elements? Pressure surge reviews. You need to understand how the pressure wave affects the operations of that particular pipeline should you have an emergency situation, shut that pipeline in.

Depth recover reviews. Fortunately in Prudhoe most of our pipes are above-ground and available for inspection. We do have some pipes that are below rivers. Close interval surveys. We don't have close interval survey requirements in Prudhoe because most of our pipes are above ground.

Low frequency RW and lap seams again. One-call activity. We don't have a one-call state here, and Prudhoe Bay is pretty well controlled from the outside public and we have guard shacks and we're a little different scenario than the rest of the 48. And then the risk profile reviews.

This is an interesting timeline for compliance. The section in this box here is what we've agreed to have in complete by December 31 of this year. And that will take us through a complete review of the integrity management program, all the elements within that program, and applying them to the DOT regulated pipes as well as to those three oil transit pipelines that I have discussed and showed you earlier.

We've identified the pipeline segments that could affect high consequence areas. We've performed the fate and transport analysis--it's in that first box here. We've established baseline assessments. As I just mentioned, we've run the final tool in the last line segment that we need to evaluate in the integrity management program. And then the next thing we have to do is review the data and perform a risk analysis. And then from that risk analysis we will be developing the risk mitigation plans, develop any repair plans that may be necessary. And then this loop over here is the continuous improvement cycle loop. All of these boxes you see have some DOT regulation sites in them. So once we complete this on December 31st, we'll get into this continuous annual loop to develop the mitigating plans, monitor and managing the risk indicators, conduct our annual inspections, review any operation data, execute and reassess, that goes back through this loop.

Now, the majority of the talk I want to spend some time on the risk assessment piece of the integrity management program. Purpose for a pipeline risk assessment, it to identify and prioritize the risks of the system so that decisions can be made as to how, where and when risk mitigation resources can be allocated to improve pipeline system integrity.

It sounds like a fairly straightforward sentence. It is not as straightforward as some may think. It's iterative and as you evaluate your risks and get more data and input, you may find that your course changes just a little bit based on all that information. And based on that information as well as integrating that information.

Characteristics of a sound risk assessment approach. One, it's got to be structured. It's got to be something that you can come back to on a regular basis. Has to have adequate resources applied. You can't do this in a vacuum with one person. While some of us might think we have all the answers, most often than not we don't. It's experience based. We want to get quite a diverse group of individuals into the room together to understand what interactions and integration has on each other. It could be predicted as to what these outcomes are going to result in.

Use appropriate data--that sounds like an easy one. Everybody has data, right? You have it in different forms, formats, and different locations. Some of it's in paper, some of it's electronic.

Very difficult to get all the appropriate information. And then you don't want to spend the 80-20 rule. You don't want to spend 80 percent of your time trying to get 20 percent of the data that has very, very little meaning to you. So you have to prioritize this data.

The ability to provide for and identify a means of feedback. You need to be able to report what the findings were, you need to be able to understand what is the result of that risk, what actions you're going to take and be able to understand what actions were taken for the next annual review. And then it's got to be documented.

In risk assessment methodology, there's two methodologies that's approved through the BP group practices. A qualitative risk assessment and a quantitative risk assessment.

The particular risk assessments we're utilizing on the integrity management program going forward starting actually today is going to be a qualitative risk using expert panel judgment and supporting data.

Again, the data that we evaluate is the key to success in this risk assessment.

Outcomes from this risk assessment. You are going to have relative risk force for each of these pipeline segments. So we're going to have a pipeline, say the pipeline's ten miles long. We may have that pipeline broken out into several segments depending on its particular risk characteristics. Such as is it more risky from a fate and transport analysis to go over a river? Or do we have different risk integrities if it's close to a road or possibly through a culvert, a caribou crossing or a road crossing?

Then we develop a risk register. We rank these things relative to each other. We come up with preventive and mitigative measures and then a re-assessment schedule.

Data gathering. Data collection approach should be appropriate to support the subjective scoring and risk by the initial expert panel. We've challenged our experts that are coming to the risk assessment reviews in their particular area of expertise to--and we actually gave them a little list of information that they needed to go out and gather. For instance, the ILI folks. They had to gather the past ILI data. They had to gather validation information as well as any other information that may lead to an analysis of what anomalies may be on that particular pipeline. We'll review that data and pre-score the risk assessment sheets before they come into the room, and then they analyze that with that information being available and publicized to everybody in this expert panel.

Data review. We have completeness of data, quality of the data, the timeliness. No sense having data that comes in after you do your risk assessment. And then importance of specific pipeline data. When you see pipeline data analysis spreadsheets they are--Frank, we're actually utilizing the Mulbauer Pipeline Risk Assessment model for this particular risk assessment. And that risk assessment has data scoring sheets and they are weighted data scoring sheets with different factors. So you could look at these factors and judge how important a particular factor is to another factor.

Data integration. This is another very, very tough piece to integrate all the data that you have available to you. We are going to be utilizing a GIS system with data layers so we can turn on and off particular data layers. If you're just looking at one set of data you may not understand the complete risk associated with that particular anomaly or location. An example of that would be you've got a smart tool run. You've got a MFL location that shows some metal loss, you're not too excited about that metal loss because it's 38 percent, you're within your error bands, you know, it's nothing too exciting. But if you couple that and overlay that data with a location that has a dent, a location that has a high strain for whatever reason--jacking VSM or sinking or in the case of Northstar, maybe a melted permafrost area. Then your concern starts to go up. So integrating this data is extremely important when evaluating the risks associated with that particular anomaly.

And also getting the data in a particular type of keyed index so we're going to utilize the pods system. The pods system has been developed over the last probably five to six years. It has been discussed in industry since DOT first came up with their integrity management program draft. It was out in regulation for public comment. The industry now has really solidified around this pods system. It's a pipeline open data standard. And it establishes standards for all of the data and that could be GIS point data, to anomaly data, to walk-by information data, to schools, to all kinds of information goes into this pods system that is then compatible from pipeline to pipeline so you can overlay it into your GIS system.

We have utilized the pods open data standard for fate and transport work that we currently perform on these pipelines that we're going to risk assess starting today through the rest of this week.

So we've got started on the pods system, we certainly don't have all the information into the pods system yet such as pressure data, but we are planning to implement the pods system for the 2007 integrity review with the data at that time will be in the pods system.

This is an example of the fate and transport study that was conducted. This happened to be on the Badami pipeline. And it's for a guillotine cut on the pipeline so it's expected that this would be the worst case scenario for a fate and transport which a pipeline spill may affect in this particular pipeline alignment. And you can see--you probably can't see because I can't even see it--but we've got pipe data down here, we've got pipeline profile data here, we've got the aerial surveys and then we run it through a particular model that was developed by New Century Software for different time periods of the release. And the maximum red time period is 100 percent loss from containment on that particular guillotine cut.

So it graphically gives you an indication of where your highest risk areas may be from a fate and transport should you have a release.

Expert panel qualifications. Risk assessment approach involves knowledgeable, experienced personnel that review the input, review assumptions and actually review results in an open forum with all of the experts. It's extremely important to have all of the experts from operations and maintenance personnel to engineering, to your environmental folks, to your integrity folks running tools and analyzing that. You've got to have them all in the room. It's amazing the conversations you get into--"Oh, I didn't know that." "I didn't know that." So it's very, very helpful.

The DOT qualification requirements are compliant with the requirements in the program.

Oh, one thing I might mention is when you train your folks if you perform your risk assessment in accordance with this type of a risk assessment model, you must also document in your training, however you set up your training within your company, you must document that. It is an item the DOT will ask for, I suspect.

Here's the techniques. I talked about the brainstorming, the issues, the risks, conduct segment by segment reviews, so if you break your pipeline segments, say you have ten miles of pipe and you broke it into five separate segments, you would go through the complete analysis for each of those segments.

You use structured questions and checklists. Again, from the Mulbauer approach we have multiple spreadsheets with particular questions that would tickle folks' mind in understanding what people were after when this question was asked and get that dialogue started.

Then you would use the simple risk matrix to qualify or to qualitatively portray and communicate the likelihood and consequences of different events. It tries to give you some understanding of the higher risks before us.

Scoring tables. Pipeline is segmented based on a consistent set of potential risks, quality and completeness of the underlying data that substantiates the subjective scoring. It's very important that you can determine that your quality and completeness of that data is good and sound.

Additional segments could be identified as part of the risk assessment process. You do that ahead of time, you understand what you think your problems are or what the differences of the risks are between segments, but as you're doing the process itself you may find that you do need to have other segments than what you originally came into.

This is a little bit of a busy flow diagram here. The risk assessment model is this basic model here. This is as simple as it gets, I think. You have your threat identification, your probability of consequences, any risk estimations, your risk evaluation and then any mitigation. As you come down into this box here it just expands these different colors here. So on these yellow boxes here--I won't have any problem with the 30 minutes--okay.

So segment score sheets, and here's your threats. These are the four areas of estimation of those risk threats identified in the Mulbauer approach. And you also have this leak impact factor as the fifth. You sum these, you multiply and divide and get some kind of relative risk scores. If you do it to all of the segments, great, if you didn't you just keep going through this box until all segments are completed. Then you sort by segment with a relative, review the results to see if it does make sense, you create the risk register and populate your boxed in squares on where your highest risks are and the consequences related to those risks. Then you develop your preventive and mitigative measures. Then you go out in the field the next week and get them accomplished.

And this is a real busy chart I'm not going to go through, but these boxes here are those four boxes that I talked about, the Muldauer approach plus that leak impact factor. These are all the things that you talk about during that risk assessment meeting and they all have relative scores in them. Very comprehensive.

Talked about staffing levels have to be adequate. We have lots of folks involved in this risk assessment review. We have Emerald Engineering, Ball Consultants, EnTech, SSD and Endicott to quite a few folks, and all these folks are here this week going through this risk assessment analysis of these pipelines.

And once you get your preventive and mitigative measures you evaluate and prepare the effectiveness of each, cost benefits, human resources required, put together a plan and a schedule. Then you also need to identify and evaluate the leak detection system and your emergency flow restricting devices. And these factors are right out of the DOT code. So there's eight factors for leak and ten factors for EFRD locations.

Then you get into that continuous review loop. You review the methods, review any new data was garnered in that reassessment year, and then you establish a reassessment period. Then it goes back into this new loop again that I showed you earlier.

IMP, Integrity Management Program, is different than the integrity of your pipeline. We've run these ILI tools in the DOT covered pipelines. And as you can see, what we don't have on here is the last run for the OT lines but all the current covered DOT pipelines have had lots of ILI tools run in them. The latest is just this year with the Northstar pipelines--both the oil and gas.

We've seen some of these this morning, just some different types of tools from geometry tools to MFL tools. This is a little bit of a tool from--called SAAM. I don't know what the acronym stands for, I should. We've talked about it enough. It's a very simple tool to get geospatial information from your pipeline. And just loads inside a cleaning pig. So the tool is just loaded in here, it's very simple. It doesn't require any special technicians to come up. Just load it and gather the data. And run it four or five times since it's a relative tool. And it gives you good enough information to determine the strain limits of your pipeline from a relative basis. So if you know what your strain is currently, you can run this pipe in and see if there's been any change to that.

An MFL tool we just recently ran. It's in the shop sitting in its cradle. It came home so some folks, you know, all dressed up and don't breathe those fumes.

And, that's it. I appreciate the time and I guess we'll take some questions.

TRANSCRIPT OF QUESTIONS FROM PANEL

M: All right we have about ten minutes for questions from the panel. Does anyone have a question for Greg? Panel? Please.

Jon Strawn of the DOT: Thanks for not asking me any questions. I have a couple questions. And that is, that you talked about right at the end of your talk about you have a leak on the W line and there is a leak on the E line East operating line, and then you pigged these operating area lines and the second two-thirds, you didn't find anything. And then on the WOA two-thirds you probably won't find anything with smart pigging on the pig. Why have you had leaks on the first segments of those pipelines and not on the second two segments of the pipeline? Can you come up with any conclusions as to why that happened and can we look forward to that on some of the other pipelines?

Greg Swank: Look forward to-- Jon, if I had an answer to that I'd probably be a consultant. It's not a part of my particular purview and I do know that we're taking chemistries and analyses and we're going through the process of identifying what the root cause of that problem was. I'd hate to speculate. I can't speculate.

Jon Strawn: I just wondered if you have the data or if you had that root cause analysis if you have any opinion on that?

Greg Swank: Nope, I'm sorry.

M: I'm not going to ask you if he answered your question.

Jon Strawn: He's working on it. He's always working on it.

M: And he was referring to a higher calling when he was talking about being a consultant. Other questions for Greg? Yes, please.

Bill Flanders: Anytime you do a risk assessment you bring in expertise, you always have I think an inherent bias to be conservative on the risk. The people that are performing the risk assessment haven't been exposed to the consequences of the failure. What I'm trying to say is, inherently people are familiar with the consequences of higher maintenance costs, of downsizing people, of having people that they know have been laid off, so they tend to be more conservative than they would in a more freer environment. Has BP thought about that particular aspect of risk assessments from in-house expertise?

Greg Swank: We try to get as diverse a group of in-house experts that we can from, again the maintenance, the operations, the ILI tool evaluators, the inspectors, HSE. We also have outside consultants assisting us and monitoring the program that we're going through this week on the risk assessment. And we're utilizing the Mulbauer scoring sheets that actually will tickle people's minds to have this kind of open discussion. There's not much that you can do with folks that don't have an ability to look beyond a conservative risk base. All you can do is try to prompt that information from them. But I don't believe you can go wrong by getting your experts that absolutely live with that pipe every day to be in that room to have those little discussions.

M: Does that answer your question? Okay. Other questions for Greg? Yes, please.

Sam Saengsudham, ADEC: Do you think that all the pipelines at least the common carrier and the OTL will be for the future pipelines?

Greg Swank: Correct.

Sam Saengsudham: Now, I know this is a question in the future, but assuming that the proposed 195 rule that passed with inspection of those specified pipes, how are you going to address that? Are you thinking about just going ahead and apply 452 or are you going to switch back to 195 to all?

Greg Swank: Depending on what the results of the pending legislation will look like--I don't know if it'll be lesser than the full compliment of 195 requirements or if it'll just incorporate the 452 requirements on integrity management. It's hard for me to answer that, Sam. Right now we had committed with those OT lines that are not currently regulated by DOT as they are low stress pipelines, into the integrity management program.

M: Does that answer your question? Other questions from the panel? Thanks, Greg. Appreciate it.

TRANSCRIPT OF QUESTIONS FROM AUDIENCE

So we do have Greg here now, so we're ready for the last round questions. And if we get through this in a timely fashion, there were a couple of others that came in a little bit late and I'll ask those as well.

First question: How many miles of pipeline on the North Slope are covered by the DOT integrity management rule?

Greg Swank: I hate to quote numbers, but around 122 total; if we include the 16 miles of the OT lines.

M: Okay. OT being? That is an acronym--what does it stand for?

Greg Swank: Oil transit lines. That's the Lisburne and the eastern operating, western operating 34 inch lines.

M: Okay. And were the pipelines that leaked in 2006 covered by the DOT integrity rule?

Greg Swank: No, the oil transit lines, the three that I described earlier first on in the presentation were operating at less than 20% SMYS and exempt from DOT regulation.

M: Any comments from the panel on that topic? Okay. This is a multiple-part question that's coming up now. What pipeline design changes are being made to address corrosion/failure problems in the pipelines?

Greg Swank: Repeat that, please.

M: Okay. What pipeline design changes are being made to address corrosion/failure problems in the pipelines?

Greg Swank: Pipelines are designed to national standards, 31.4 to 31.8 for gas, 31.4 for liquids. So if the question is related to the national standards, I'm not on those committees, so I'm not certain. Bill might be able to answer on one of those committees. But I don't know that they have anything on their agenda to change a design standard.

Jon Strawn: The only thing that I can think of is that BP on the OTL lines is going to put in all new piping. It's going to be 18 inch piping where the fluid will now be able to higher velocity, compared to these old 30 to 34 inch lines. So it is to me like that's an inherent design change if you've already decided to put in that new pipe. Is that a correct statement?

Greg Swank: I wouldn't characterize that as a design change for the pipeline. You design a pipeline for whatever its particular velocities and capacities are, as well as pressures. So we design all of those pipes to a national standard. So I would say that the standard hasn't changed.

Jon Strawn: So I just threw that out as a comment, that you are planning on installing new 18 - 24 inch line.

Sam Saengsudham: I would just like to add that you should make sure those lines are piggable.

Greg Swank: They are currently piggable.

Bill Flanders: The current ASME B31.4, doesn't address pipelines operating under 20% SMYS. You may voluntarily apply those standards to the design of a pipeline that would operate in those regions.

Chris Dash: ConocoPhillips has modified our external insulation so that we are reducing our risk of external corrosion hazards. So I think that's a pretty big change--namely because one of the biggest threats on the North Slope is corrosion under insulation--not just internal corrosion.

M: Other comments? This is addressed to Greg, but I'm not too sure that you're going to be able to answer this. Other panelists may have to jump in here. Are any new standards being developed to address corrosion/failure problems. ASME, API, ANSI, ASTM? New pigging techniques, metallurgy, anything new, that you are aware of in the standards area?

Bill Flanders: ASME B31.4 is writing a corrosion section which will be incorporated in the next revision of B31.4. How much that change is, I'm not sure that it would address internal corrosion specifically or to the extent that the person that wrote that question would want, but there is a new section coming out of B31.4. And that more closely aligns itself to these standards.

M: Okay. Any other comments?

Pat Vieth: The NACE has also developed a whole series of recommended practices. One currently under development is the petroleum ICDA. Internal Corrosion Direct Assessment methodology.

M: Any other comments? Okay. Will all pipeline integrity data be managed within the pods data format.

Greg Swank: The expectation is that yes, at the end of 2007 we will be managing our data in the pods format. Now, again, that's an expectation. There's a lot of data mining that has to take place, there's huge data records just pertaining to one area and that would be smart pig data. So to convert all that in time specific for one year is a heck of an undertaking so there is no guarantee it will be all converted to pods at that time. We are going toward the pods standards.

M: And that includes historical data?

Greg Swank: Absolutely. Historical data has to be characterized in a method that allows you to integrate that into the GIS system for risk analyses. It makes it a lot easier.

M: Okay. I assume nobody else has any comments on that. Anybody? Okay. Will the risk assessment evaluate currently allowable levels of sediment and water in sales oil quality, oil quality crude as a risk factor for internal pipe corrosion?

Greg Swank: Yes, we are establishing every time that we get pig returns information, those pig returns data are being analyzed for corrosion properties. They will then be rolled up into the annual risk assessment analysis.

M: Okay. And then here's kind of a statement. I think there's a question here, but I'll read it. Isn't the BP situation on the North Slope an indictment of the risk assessment process? That is, the low stress pipelines which had problems were determined to be "low risk" pipelines and thus given less attention than higher risk pipelines like the multi-phase lines from wells.

Greg Swank: Well, I wasn't in charge of those particular low stress pipelines. As I said earlier, I was mostly concerned with the DOT regulated pipelines, but everything I understand on those lines, we had an external corrosion program that we thought was well in hand. So I wouldn't say that it was less of a risk factor that we have evaluated, but obviously when these kind of things happen you always learn.

M: Other comments from the panel? Okay. I'm going to try this. I'm sure it will make sense to everybody on the panel. But this one says, "Which ASME"--and then it has "B31.3, 4, 8 codes have the most corrosion failure problems and why?"

Greg Swank: I certainly don't have information from the Prudhoe Bay lines on which 31.4, 31.3, 31.8, lines have more failure than any other. I don't know that we categorize our lines by a design specification or code requirement. I'd look for others on the panel to shed some light on that.

M: Anybody have an answer to that question? Okay. Are more North Slope pipelines going to be under part 195 regulations?

Greg Swank: Well, as we discussed earlier in the day, in my presentation and what Jon was talking about, that the low stress pipelines rule-making is currently undergoing public notice, and most certainly those lines will be incorporated in the DOT purview.

M: That's the last question for you, Greg. Thank you. Okay.

APPENDIX L

INTELLIGENT PIGGING CONFERENCE EXHIBITOR INFORMATION

Internal pipeline inspection services

Ultrasonic Piglet

THE PIGLET SYSTEM

Special for relative short “non-standard piggable” pipelines A. Hak Industrial Services designed an intelligent versatile tethered intelligent pigging system which is still attached to an ‘umbilical’. Despite this ‘umbilical’ it still has the ability to inspect pipeline lengths up to 12 kilometer in one run, negotiate an unlimited number of bends, is able to travel in two directions, has the ability to inspect multiple diameters in one inspection run, and provide all ultrasonic measurements on-line.

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The success of the Piglet is based on the patented ‘umbilical’ design and storage. Instead of using strong relative thick cables, the Piglet is using a glass fiber optic which has a diameter of less then 1 mm. This glass fiber optic is not stored on a winch, which is placed outside the pipe, but stored on a patented unwinding reel which is stored in the Piglet itself. This results in an operational mode whereby the glass fiber optic is not pulled into the pipe whilst the Piglet is pumped into the pipeline, but merely unreels the glass fiber whilst it is progressing to the end.

PIGLET SYSTEM CONFIGURATION

The Piglet is typically configured as per the below shown diagram. The most important aspects of the system are:
- ultrasonic measuring head;
- Piglet;
- fiber wire;
- data acquisition system.

PIGLET INSPECTION RANGE

Diameter	*Max. length**	*Insp. speed*
4”	*2 km*	*500 m/h*
6”	*6 km*	*500 m/h*
8”	*12 km*	*500 m/h*
10” – 18”	*12 km*	*250 m/h*
20” – 36”	*12 km*	*125 m/h*
40” – 48”	*12 km*	*75 m/h*

* Based on client requirements, we can redesign tools up to an inspection length of 35 km

PIGLET OPERATIONAL ASPECTS

The Piglet is sent through the pipeline in a similar way as a conventional pig. In other words it requires a fluid in the pipeline for propulsion, and a differential pressure over the Piglet system. The Piglet can in such a manner be pumped forward and backward through the pipeline. In order to accommodate the customer, A. Hak has built a complete range of temporary launchers and receivers that can easily be attached to the line. Also complete pumping and monitoring arrangements can and will be provided as part of the package.

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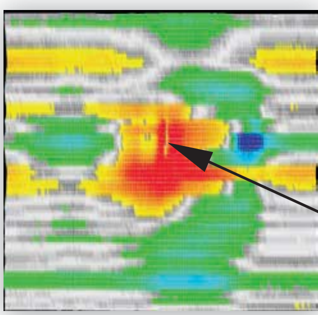

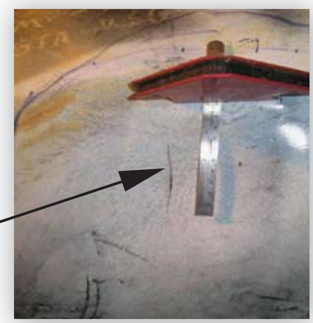

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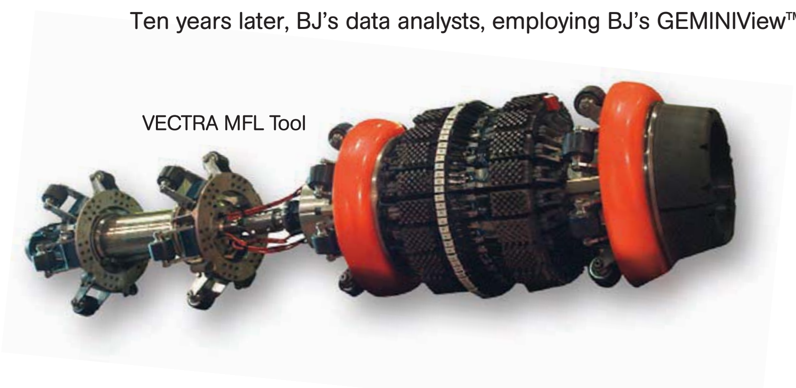

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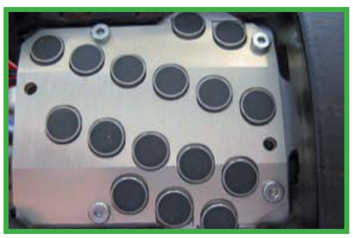
24" LineExplorer UC



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8" Sensor Carrier Confi guration UC

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Available Confi gurations

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Metal loss	■		■	
Laminations and mid-wall flaws	■		■	
Narrow axially extended corrosion	■			
Pitting	■			■
Cracks, stress corrosion cracking (SCC): axial orientation		■	■	
Cracks, stress corrosion cracking (SCC): circumferential orientation		■		■
Crack inspection, spirally welded pipe		■		■
High temperature	■	■	■	■
High pressure	■	■	■	■
Bi-directional mode	■	■	■	■
Non-piggable	■	■		■
Dual- and multi-diameter	■	■		■

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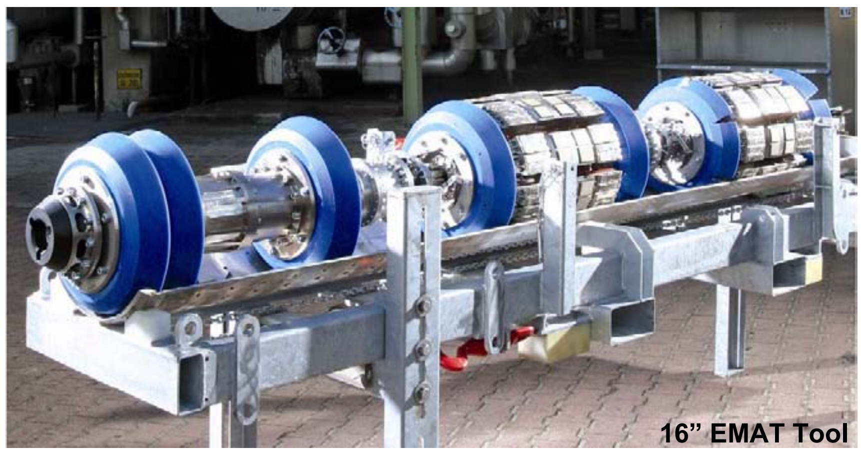
56” Axial Flaw Detection Pig


12” RPS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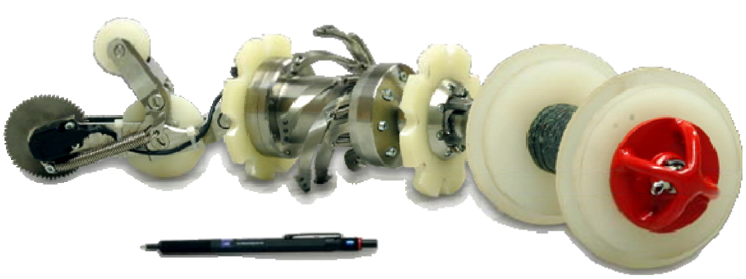

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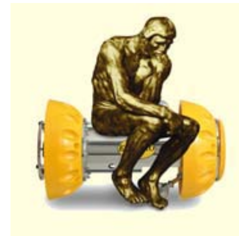

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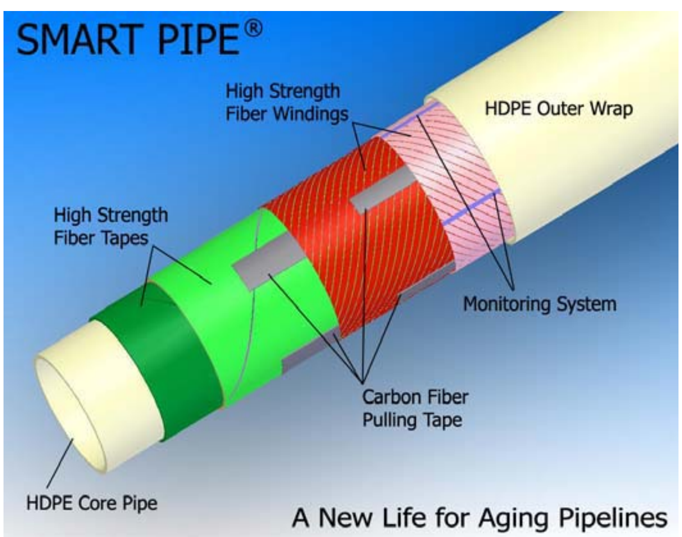

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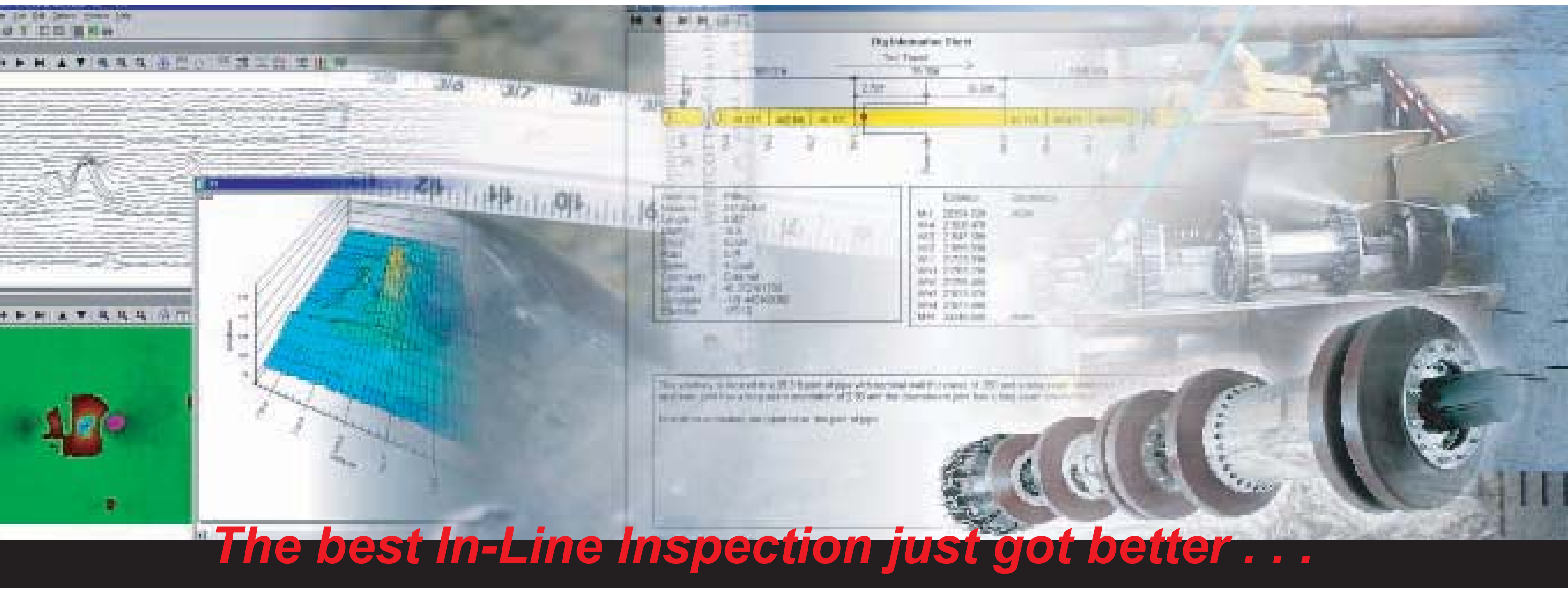

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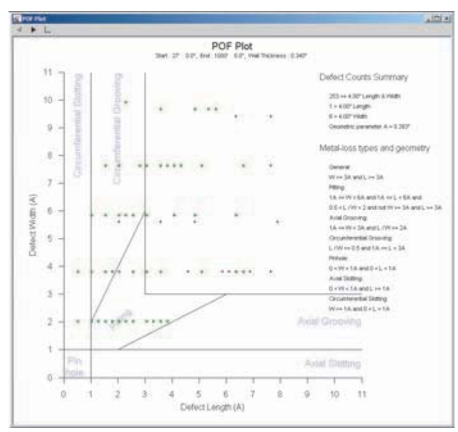

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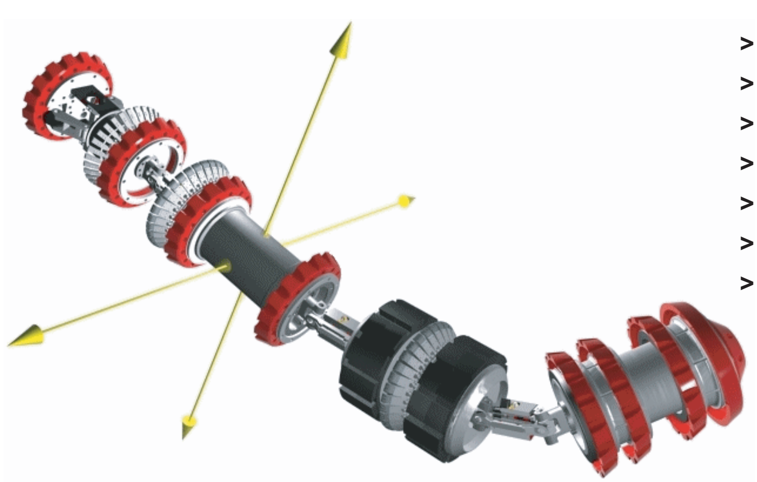

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