Pipeline Leak Detection Technology Conference

Pipeline Leak Detection Technology
2011 Conference Report

Final Report
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**Alaska Department of Environmental Conservation
Division of Spill Prevention and Response
Industry Preparedness Program
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Pipeline Leak Detection Technology
2011 Conference Report
Anchorage, Alaska

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EXECUTIVE SUMMARY

This document presents a summary of the Alaska Department of Environmental Conservation (ADEC) sponsored Pipeline Leak Detection (PLD) Technology Conference (Conference) that took place on September 13 and 14, 2011. Implementation of the 2011 PLD Technology Conference and development of this Conference report was conducted under Shannon & Wilson's ADEC Term Contract, Division of Spill Prevention and Response No. 18-4002-12. This project consisted of a review of proven PLD technologies and related practices used worldwide, facilitation of a PLD Technology Conference in Anchorage, Alaska, and this Conference report which includes a review and appraisal of the presented technologies.

In accordance with Title 18 of Alaska Administrative Code Chapter 75.447 (18 AAC 75.447), ADEC is tasked with sponsoring a technology conference at least every five years in cooperation with persons, organizations, and groups with interests and expertise in relevant technologies. This is the fourth technology conference held since 2004. Additionally, one of the recommendations from the Alaska Risk Assessment Project, conducted between 2007 and 2010, was to consider new requirements for pipeline leak detection by having ADEC sponsor a conference to investigate advances in pipeline leak detection technologies. The intent of the 2011 PLD Technology Conference was to assess pipeline leak detection technologies and related practices for flow lines, crude oil transmission pipelines, and other oil pipelines including facility oil piping. The goal of the 2011 PLD Technology Conference was to gather information from experts in the field of pipeline leak detection technology including related practices; examine how proven or promising technologies and related practices could be applied to Alaska's pipelines; and identify the best technologies and related practices that may be employed on Alaska pipelines.

There are internally (observing hydraulic behavior) and externally (released fluid detection) based PLD technologies. A detailed discussion of PLD technologies currently available is presented in Sections 1 through 7 of UTSI International Corporation's *Alaska Department of Environmental Conservation 2011 Leak Detection Conference Technology Analysis* report, provided in Appendix A.

Sixteen PLD technology providers presented their products and/or services at the Conference including products, practices, and equipment associated with meter-based solutions, vapor detection and liquid sensing solutions, fiber optics, and meters. UTSI concluded in their analyses of the sixteen presentations, provided in Sections 8 through 10 of Appendix A, that none of the tools described at the Conference are considered breakthrough technologies since each technology has already been deployed somewhere in Alaska. Furthermore, internally-based pipeline leak detection technology in Alaska has a record of being thwarted by thermal issues that cause false alarms and may mask real leaks. The conference clearly showed that there are

commercial products available that can significantly improve leak detection performance on pipelines with thermal issues. One internally-based tool described in the conference has been tested and reported to have shortened detection time in a fluid withdrawal test from fourteen hours to under one hour compared to the incumbent system on the pipeline.

UTSI made no declarations regarding what technology is applicable on a given pipeline. UTSI emphasizes that the selection and deployment of any particular leak detection system should be based on the suitability of the technology for the unique operational characteristics of the pipeline.

Identifying a leak equal to one percent of a day's throughput should <u>not</u> always be considered a satisfactory level of protection. Instead, the 1% criterion should be considered an absolute minimum level of performance for pipelines. Some external leak detection technologies may be worthy of deployment as a primary system on large capacity lines due to their potential to significantly limit released fluid volumes. External leak detection technologies may also be applicable as a secondary leak detection method to extend leak detection sensitivity or shorten detection time.

As important as detecting a leak is, the controller's response is equally critical. There have been several cases where the leak detection system detected an actual leak and declared an alarm which was ignored by the controller.

Specific operations, geographical locations, and physical environments where the PLD technologies presented at the Conference could be applied are identified. No one technology or commercially available product is suitable for any or all pipelines operations in Alaska or superior to others in all cases. The UTSI report, in Appendix A, provides the necessary information for staff with detailed familiarity with a given pipeline to evaluate whether a technology or commercially available product is suitable for their pipeline. Selecting the right leak detection product or products is critical for successful detection of leaks at the lowest feasible detection threshold and shortest detection time and requires a cooperative effort involving the pipeline operator and potential suppliers of leak detection products.

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LIST OF ACRONYMS AND ABBREVIATIONS

AAC	Alaska Administrative Code
A/D	Analog-to-Digital
ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
BAR	One atmosphere of pressure (around 14.7 PSI)
BAT	Best Available Technology
BOTDA	Brillouin Optical Time Domain Analysis
BPD	Barrels per day
BPXA	BP Exploration Alaska
C	Centigrade
CFR	Code of Federal Regulations
C-Plan	Oil Discharge Prevention and Contingency Plan
CPM	Computational Pipeline Monitoring
DC	Direct Current
DEC - PDP	Digital Equipment Corporation - Programmed Data Processor
DSTS	Distributed Strain and Temperature Sensor
DTS	Distributed Temperature Sensing
DVS	Distributed Vibration Sensor
EFA	Ed Farmer & Associates
EPA	Environmental Protection Agency
F	Fahrenheit
FFS	Fast Fuel Sensor
FKA	Formerly Known As
GIS	Geographic Information System
GPS	Global Positioning System
HCA	High Consequence Area
HCL	Hydrochloric Acid
HMI	Human Machine Interface
IATA	International Air Transportation Association
IEC	International Electrotechnical Commission
IR	Infrared
LNG	Liquified Natural Gas
MOP	Maximum Operating Pressure

LIST OF ACRONYMS AND ABBREVIATIONS (Continued)

MOV	Motor Operated Valve
NTP	Notice to Proceed
OGI	Optical Gas Imaging
OPC	Object Linking and Embedding Process Control
OT	Oil Transit
%	Percent
PD	Positive Displacement
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	Programmable Logic Controller
PLD	Pipeline Leak Detection
PRCI	Pipeline Research Council International, Inc.
PSI	Pounds per square inch
P/T	Pressure and Temperature
Q&A	Question and Answer
RFID	Radio Frequency Identification
RFP	Request for Proposal
ROW	Right-of-Way
RTD	Resistance Temperature Detector
RTSA	Real Time Statistical Analysis
RTTM	Real-Time Transient Model
RTU	Remote Terminal Unit (includes PLCs and other field devices)
SCADA	Supervisory Control and Data Acquisition
SPRT	Sequential Probability Ratio Test
TAPS	Trans Alaska Pipeline System
TCP/IP	Transmission Control Protocol/Internet Protocol
TCS	Tightness Control System
TDMA	Time Division Multiple Access
TDR	Time Domain Reflectometry
TT	TraceTek
VPN	Virtual Private Network

PIPELINE LEAK DETECTION TECHNOLOGY
2011 CONFERENCE REPORT
ANCHORAGE, ALASKA

1.0   INTRODUCTION

This document presents a summary of the Alaska Department of Environmental Conservation (ADEC) sponsored Pipeline Leak Detection (PLD) Technology Conference (Conference) that took place on September 13 and 14, 2011. The Conference was conducted in accordance with Title 18 of Alaska Administrative Code Chapter 75.447 (18 AAC 75.447). The purpose of the Conference was to provide entities with expertise in PLD an opportunity to describe the status of existing technologies in use, as well as technologies (including related practices) that may be considered superior to those currently in use. This Conference report identifies current PLD technologies and related practices that ADEC considers may significantly enhance leak detection performance on existing pipelines. The objective of the project was to gather information from experts in the field of PLD technology including related practices; examine how proven or promising technologies and related practices could be applied to Alaska's pipelines; and identify the best technologies and related practices that may be employed on Alaska pipelines.

This project was authorized under Shannon & Wilson's ADEC Term Contract, Division of Spill Prevention and Response No. 18-4002-12. Implementation of the 2011 PLD Technology Conference and development of this Conference report was performed in general accordance with the ADEC February 22, 2011 Request for Proposal (RFP) document, the Shannon & Wilson technical proposal dated March 15, 2011, and Shannon & Wilson's cost proposal dated March 21, 2011. ADEC authorization to proceed with this project task was received on March 25, 2011 with Notice to Proceed (NTP) No. 18-4002-12-021, as amended with NTPs 21B, 28, and 28B.

1.1 Background

In accordance with 18 AAC 75.447, ADEC is tasked with reviewing and appraising technologies applied at other locations in the United States and the world that represent alternatives to the technologies used by plan holders in their oil discharge prevention and contingency plans (C-Plans) submitted to meet response planning standards in 18 AAC 75.430- 18 AAC 75.442 and the performance standards of 18 AAC 75.005 – 18 AAC 75.080. ADEC conducts this review and appraisal by sponsoring a technology conference at least every five years in cooperation with persons, organizations, and groups with interests and expertise in relevant technologies. A Best Available Technologies (BAT) Conference, during which PLD technologies and related practices were addressed, was held in May 2004, a Maintenance Pigging of Pipelines Conference was held in October 2006, and an Intelligent Pigging of Pipelines Conference was held in November 2006.

In 2007, the State of Alaska initiated the Alaska Risk Assessment Project to assess the risks and reliability of the existing oil and gas infrastructure if it is operated for another generation. The results of the Alaska Risk Assessment Project efforts to-date have been documented in the following three November 2010 reports:

- *Summary of Phase 1 Alaska Risk Assessment Accomplishments and Challenges*,

- *Review of Select Foreign & Domestic Approaches to Oversight & Management of Risk & Recommendations for Candidate Changes to the Oversight Approach for the Alaska Petroleum Transportation Infrastructure*, and

- *Final Report on North Slope Spills Analysis and Expert Panel Recommendations on Mitigation Measure*.

One of the recommendations from the Alaska Risk Assessment Project was to identify and investigate new or existing state-of-the-art technologies that could improve leak detection sensitivity for North Slope crude oil transmission pipelines and multiphase flow lines. The intent of the 2011 PLD Technology Conference was to assess pipeline leak detection technologies and related practices for flow lines, crude oil transmission pipelines and other oil pipelines such as facility oil piping. One of the goals of the 2011 PLD Technology Conference was to identify technologies and products that enable the discovery of smaller leaks faster than is typical with existing systems frequently used in Alaska. The results of the review and appraisal of technologies presented at the 2011 PLD Technology Conference may be used to develop new leak detection regulations for flow lines, those pipelines that convey multi-phase fluids between well sites and processing facilities. The ADEC does not currently have response or performance standards or regulations for pipeline leak detection for flow lines or facility oil piping. The only pipeline leak detection requirements for these categories of pipelines are specified in 18 AAC 75.047(d) which state that:

- No later than December 30, 2007, the operator shall completely contain the entire circumference of the flow line and provide the interstitial space with a leak detection system approved by the department; or have in place a preventative maintenance program that ensures the continued operational reliability of any flow line system component affecting quality, safety, and pollution prevention.

The pipeline leak detection requirements for crude oil transmission pipelines are specified in 18 AAC 75.055(a). The requirements state that:

- A crude oil transmission pipeline must be equipped with a PLD system capable of promptly detecting a leak including:

1. If technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;

2. Flow verification through an accounting method, at least once every 24 hours; and

3. For a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

1.2 Project Description

This project consisted of a review of proven PLD technologies and related practices used worldwide, facilitation of the PLD Technology Conference in Anchorage, Alaska, and this Conference report which includes an analysis of the presented technologies. Shannon & Wilson used several methods to review the PLD technologies including subcontracting with a PLD technology expert from UTSI International Corporation (UTSI) to provide guidance in researching and evaluating existing technologies; investigating current and alternate technologies discussed in existing C-Plans; conducting a technology search; and interviewing individuals knowledgeable of proven technologies used worldwide.

Shannon & Wilson solicited input from technology providers about their PLD products or related practice. Shannon & Wilson and the PLD technology expert, in conjunction with the ADEC project manager, selected presenters for the Conference. The PLD Technology Conference was held at the Sheraton Anchorage Hotel and comprised five sessions. During the first session, a technology user group panel discussed challenges and problems users face when selecting and using PLD technologies. The other four sessions included presentations by PLD technology providers about meter-based solutions and practices, vapor detection and liquid sensing solutions, fiber optics, and meters. Brief Question and Answer (Q&A) Sessions were held after each presentation with the presenters and the PLD technology expert. In addition, Q&A sessions were held following the final presentation for each session to generate participation between the audience, presenters, and the PLD technology expert. An Exhibit Hall was set up adjacent to the Conference room to provide a location where PLD technology providers were able to display their products during the two-day event.

Shannon & Wilson was responsible for providing facility planning, conference organization, and documenting conference proceedings. Mr. Randy Allen of UTSI served as the PLD technology expert and provided guidance to Shannon & Wilson for implementing the 2011 PLD Technology Conference and the *Alaska Department of Environmental Conservation 2011 Leak Detection Conference Technology Analysis* report, provided in Appendix A. Ms. Julie Jessen of HDR Alaska, Inc. facilitated the conference proceedings as the Conference Moderator. Ms. Karen Zac of Visions assisted Shannon & Wilson in planning and facilitating the Conference and Exhibit Hall. UTSI, HDR, and Visions provided their services under subcontract to Shannon & Wilson.

This report documents the review and appraisal of PLD technologies and related practices for the 2011 PLD Technology Conference.

2.0   PIPELINE LEAK DETECTION TECHNOLOGY DESCRIPTION

There are internally (observing hydraulic behavior) and externally (released fluid detection) based PLD technologies. Computational pipeline monitoring (CPM) is an internally based PLD technology defined in the American Petroleum Institute (API) Recommended Practice 1130, *Computational Pipeline Monitoring for Liquids*. CPM uses pressure, flow, temperature, and/or acoustic instruments to measure single or multi-phase fluid parameters within a segment of pipeline. A Supervisory Control and Data Acquisition (SCADA) system monitors, processes, transmits, and displays the pipeline data to a controller in a control room. Various computer software programs are available to analyze the information and issue an alarm when a leak is detected. External methods include hydrocarbon vapor or liquid-sensing devices as well as aerial surveillance along pipeline corridors. Typical external devices include systems employing optical fibers, acoustic sensors, chemical sensors, and electrical sensors. Visual observations from vehicles or aircraft and/or hydrocarbon and thermal sensing devices strategically positioned along pipeline right-of-ways are commonly used external PLD technologies. A detailed discussion of PLD technologies currently available is presented in Sections 1 through 7 of the UTSI PLD technology expert's *Alaska Department of Environmental Conservation 2011 Leak Detection Conference Technology Analysis* report, provided in Appendix A.

Shannon & Wilson, with guidance from the PLD Technology Expert, identified twenty-nine PLD technology providers for potential presentations at the Conference. These PLD technology providers were contacted and invited to provide presentations at the 2011 PLD Technology Conference. Sixteen PLD technology providers presented their products and/or services at the Conference. The technology provider and technology names, contact information, and a description for each of these sixteen PLD technologies are listed in Table 1. The remaining thirteen PLD technology providers did not attend the Conference for various reasons.   The technology provider and technology names, website address, and a description for these thirteen other PLD technologies are provided in Table 2.

3.0   SUMMARY OF CONFERENCE PRESENTATIONS

The technologies presented at the 2011 PLD Technology Conference included products, practices, and equipment associated with meter-based solutions, vapor detection and liquid sensing solutions, fiber optics, and meters. Various PLD technologies are available and one or more technology may be necessary to achieve the desired goals for an individual pipeline.

3.1 Session 1 - PLD Technology Users Group Panel Discussion

Operating a pipeline in Alaska presents numerous challenges with regard to fluid management; maintaining flowing conditions for example. Consequently, leak detection technologies and tools have had varying degrees of success due to fluid characteristic changes during transit.   A PLD technology users group panel was assembled from some of the key pipeline operators present in the state, including ConocoPhillips Alaska, Inc., Alyeska Pipeline Service Company, and Tesoro Alaska Company. The panel discussed a few of the challenges encountered by the various entities operating pipelines in Alaska through three presentations.

3.1.1 Key Metrics in Selecting, Deploying, and Supporting a CPM PLD System on the North Slope

Mr. Dave Alzheimer, representing ConocoPhillips Alaska, Inc., discussed some of the general challenges facing pipeline operators. ConocoPhillips has operations in Kuparuk, located on the Alaska North Slope, as well as operations in the Cook Inlet area, specifically Kenai, Tyonek, and Beluga River. Numerous considerations are necessary in designing a PLD system based on available products and can generally be broken down into process characteristics, field instrumentation and data interface, the leak detection engine/algorithms, and the human machine interface (HMI). The effect of how each of these components impact success depends on the specific characteristics of the individual pipeline and strengths of each leak detection product. Each pipeline is different and requires individual considerations for PLD system selection and design. Pipelines have different flow rate patterns, fluid/chemical properties, and temperature variations. The specific goals of pipeline leak detection include desired sensitivity, leak detection time, leak location capability, accuracy of leak volume estimates, and adaptability of a given technology to routine and non-routine activities. These goals impact system selection for a pipeline. Pipeline field instrumentation, data interface, and telecommunication properties also present limitations or constraints. Options for integrating the PLD system with SCADA and its HMI are also a major factor. Incorporating each of these components into selection of a PLD system takes careful consideration and the compatibility and flexibility of a specific vendor and/or technology should also be taken into account. The main topics of discussion included in Mr. Alzheimer's presentation are itemized in Section 8.1.1 of Appendix A.

3.1.2 Difficulties with Maintaining CPM Leak Detection System During Times of Low Throughput

Dr. Morgan Henrie of MH Consulting, discussed challenges associated with Alyeska's operation of the Trans Alaska Pipeline System (TAPS), extending from Prudhoe Bay to Valdez. The throughput of the TAPS has decreased since the 1980s, and is currently projected to continue to decrease. Based on regulatory requirements, a PLD system should be able to detect a leak as

small as 1 percent (%) of the daily throughput. Therefore, as the throughput decreases the sensitivity of the PLD system has to increase in order to meet the regulatory requirement. The uncertainties in flow, fluid properties, modeling accuracy, and other components of a pipeline and PLD system further complicate achieving the 1% requirement. Variable throughput creates a situation where the selected PLD system must be able to meet the required sensitivity metric under all conditions. The main topics discussed in Dr. Henrie's presentation are itemized in Section 8.1.2 of Appendix A.

3.1.3   Challenges to Operating and Selecting a PLD on Kenai to Anchorage Pipeline

Mr. Gillus Moore, representing Tesoro Alaska Company, addressed challenges encountered with transporting their product from the Kenai Refinery to the Port of Anchorage and the Anchorage International Airport. In general, selecting the appropriate PLD system requires a clear understanding of the specific pipeline characteristics, the measurement systems and equipment currently in use, and the expectations of the operators using the system. The second component in PLD system selection is recognizing the performance level desired from the system. Achieving certain performance goals may require sacrificing others, or require additional systems to compensate or augment the selected primary PLD system. Specific challenges faced by Tesoro include temperature and volume change as fluid density varies during transit, slack line effects, and other challenges associated with operating in a non-steady-state mode (startups, transient conditions, and control operations). The main topics discussed by Mr. Moore are itemized in Section 8.1.3 of Appendix A.

3.1.4   Q&A for PLD Technology Users Group Panel

Mr. Allen of UTSI asked the users group panel questions pertaining to: usual procedures following a leak alarm, specifically what the role of the controller has in this determination; testing a prospective PLD system with live data prior to purchasing a system; managing slack line conditions; and challenges with temperature. Conference attendees asked questions regarding: differences in handling pipelines traversing populated versus non-populated areas; causes of leaks encountered on the pipeline; discussion of the human component in PLD systems; ongoing testing following installation of a PLD system; and temperature and pressure compensation of flow measurements. Additional details of the Q&A session questions and responses are provided in Section 8.1.4 of Appendix A.

3.2 Session 2 – Meter-Based PLD Solutions and Related Practices

Meter-based PLD solutions that use a combination of measured pressure, flow, temperature, volume and/or acoustic waves for detecting leaks were presented during this PLD technology conference by several companies. The companies presenting technologies included ATMOS

International, Inc.; Krohne Oil & Gas; hansaconsult Ingenieurgesellschaft; Vista Leak Detection, Inc.; Telvent USA Corporation; and Siemens. In addition MH Consulting presented a discussion on temperature variations and PLD selection.

3.2.1   ATMOS Pipe® and ATMOS Wave by ATMOS International, Inc.

Mr. Michael Twomey, president of ATMOS International Inc., presented the patented ATMOS™ Pipe Real Time Statistical Analysis (not to be confused with a real-time transient model).   ATMOS™ Pipe employs statistical analysis software to minimize false leak alarms. The main topics discussed by Mr. Twomey are itemized in Section 8.2.1 of Appendix A. The PowerPoint presentation slides for the ATMOS™ Pipe Real Time Statistical Analysis Software technology presentation are included in Appendix B. Additional information about ATMOS Pipe® can be obtained by visiting the ATMOS website at www.atmosi.com.

3.2.2   PipePatrol by Krohne Oil & Gas

Mr. Daniel Vogt of Krohne Oil & Gas presented the PipePatrol Leak Detection and Localization System. PipePatrol is a real time transient model. Using temperature and pressure measurements at the inlet and the outlet along with flow measurements, a virtual pipeline is calculated and a model is produced which provides the hydraulic profiles of the pipeline in real time. The main topics of discussion included in Mr. Vogt's presentation are itemized in Section 8.2.2 of Appendix A. The PowerPoint presentation slides for the Krohne PipePatrol technology presentation are included in Appendix C. Additional information about PipePatrol can be obtained by visiting the Krohne internet web site at www.krohne.com.

3.2.3   TCS "Tightness Control System" by hansaconsult Ingenieurgesellschaft

Mr. John Birnie, Vice President of Hansa Systems LLC, hansaconsult Germany's United States office, presented the TCS. The TCS is based on a pressure step method technology under non-flowing conditions.   The main topics discussed by Mr. Birnie are itemized in Section 8.2.3 of Appendix A. The PowerPoint presentation slides for the hansaconsult TCS technology presentation are included in Appendix D. Additional information about TCS can be obtained by visiting the hansaconsult website at www.hansa-leakdetection.de/.

3.2.4   LT-100 and HT-100 by Vista Leak Detection, Inc.

Mr. Doug Mann presented the Vista Leak Detection, Inc. LT-100 and HT-100 technologies. They are dual pressure, precision volumetric tests for leak detection on pipeline segments under static conditions.   The main topics of discussion included in Mr. Mann's presentation are itemized in Section 8.2.4 of Appendix A. Additional information about LT-100 and HT-100 can be obtained by visiting the Vista Leak Detection website at www.vistaleakdetection.com.

3.2.5   SimSuite Pipeline by Telvent USA Corporation

Mr. Kelly Doran, of Telvent USA Corporation, presented the SimSuite Pipeline technology. SimSuite Pipeline uses real time modeling and the compensated mass balance method for leak detection. The main topics discussed by Mr. Doran are itemized in Section 8.2.5 of Appendix A. The PowerPoint presentation slides for the Telvent SimSuite Pipeline technology presentation are included in Appendix E. Additional information about SimSuite Pipeline can be obtained by visiting the Telvent USA Corporation website at www.telvent.com.

3.2.6   FUS-LDS by Siemens

Mr. Paul Murphy and Mr. Rocky Zhang of Siemens, presented FUS-LDS. The FUS leak detection systems are based on a compensated volume balance method that continually monitors the difference in flow rate between clamp-on ultrasonic meters located typically at the beginning of a pipeline and the end of a pipeline. Significant points included in Mr. Murphy's and Mr. Zhang's presentation are itemized in Section 8.2.6 of Appendix A. Additional information about FUS-LDS can be obtained by visiting the Siemens website at www.sea.siemens.com.

3.2.7   Selecting PLD for a Transmission Pipeline with Temperature Variations as Product Is Conveyed Downstream by MH Consulting

Dr. Morgan Henrie and Mr. Ed Nicholas described the impact that thermal effects have on selection of a PLD system. The main topics discussed by Dr. Henrie and Mr. Nicholas are itemized in Section 8.2.7 of Appendix A. The PowerPoint presentation slides for the MH Consulting presentation are included in Appendix F.

3.2.8   Q&A for Session 2 - Meter-Based PLD Solutions and Related Practices

A Q&A session took place following completion of the Session 2 presentations. Questions were submitted on index cards and were addressed to either the whole group or individual presenters. General questions were asked about: published comparison of detection time versus leak rate for individual systems; correlations between false alarm rates and response times; PLD systems that are successful with aboveground pipeline systems in the arctic climate; what flow meters are the best; the ability of hydraulic models to handle low velocities; accuracy and precision of noise filters on measurements; standardization of field meters to achieve desired accuracy of a PLD system; and the need for power supply to operate PLD systems in remote locations. Vendor specific questions were also submitted. A complete list of questions and answers is provided in Section 8.2.8 of Appendix A.

3.3 Session 3 - Vapor Detection and Liquid Sensing PLD and Related Practices

Vapor detection and liquid sensing PLD systems are external PLD technologies that use a variety of methodologies including air sampling, infrared cameras, and sensing cables. Companies presenting their vapor detection and liquid sensing technologies included AREVA NP GmbH, FLIR, Tyco Thermal Controls, and PermAlert ESP, a Division of Perma-Pipe, Inc.

3.3.1   LEOS by AREVA NP GmbH

Dr. Walter Knoblach of AREVA NP GmbH, presented LEOS technology. LEOS technology is an intelligent air sampling system designed to detect leaks that are below the threshold of detectability by meter-based methods. Significant points included in Dr. Knoblach's presentation are itemized in Section 8.3.1 of Appendix A. The PowerPoint presentation slides for the AREVA NP GmbH LEOS technology presentation are included in Appendix G. Additional information about LEOS can be obtained by visiting the AREVA website at http://www.areva-diagnostics.de/en/.

3.3.2   GF-300 Optical Gas Imaging Infrared Camera System by FLIR

Mr. David Shahon of FLIR presented GF-300 Series OGI Infrared Cameras. The OGI infrared camera system uses thermal imaging tuned to identify VOC gas vapors. This system can be used to detect leaks in oil-filled and gas-filled pipes as vapors given off will be visible to the FLIR GF300 camera system. The main topics discussed by Mr. Shahon are itemized in Section 8.3.2 of Appendix A. The PowerPoint presentation slides for the FLIR GF-300 Series OGI Infrared Cameras technology presentation are included in Appendix H. Additional information about OGI can be obtained by visiting the FLIR website at http://www.flir.com.

3.3.3   TraceTek 5000 Hydrocarbon Sensor Cable and TT-FFS Fast Acting Fuel Probes by Tyco Thermal Controls

Mr. Ken McCoy of Tyco Thermal Controls presented TraceTek (TT) 5000 Hydrocarbon Sensor Cable, TT-FFS fast acting fuel probes, TTSIM Sensor Interface, and TTDM-128 Alarm Panels. TraceTek uses sensor cables and probes that interact with spilled liquid hydrocarbons producing electrical changes in the cable that are monitored by sensor interfaces and alarm panels to detect leaks and leak location. The main topics of discussion included in Mr. McKoy's presentation are itemized in Section 8.3.3 of Appendix A. The PowerPoint presentation slides for the Tyco Thermal Controls TraceTek (TT) 5000 Hydrocarbon Sensor Cable, TT-FFS fast acting fuel probes, TTSIM Sensor Interface, and TTDM-128 Alarm Panels technology presentation are included in Appendix I. Additional information about these technologies can be obtained by visiting the Tyco Thermal Controls website at http://www.tracetek.com or http://www.tycothermal.com.

3.3.4   P-600 Infrared Camera System Thermal Imaging by FLIR

Mr. David Shahon of FLIR presented the P-600 Camera. The P-600 is an infrared camera system that can be used to detect leaks in two different ways. In the first method, an actual leak will cause a difference in temperature in the surrounding water surface area. Oil on water is easier to identify from farther away with an IR camera. The second method includes viewing temperature differences on insulated pipe. An anomaly or thermal non-uniformity can mean that the insulation is wet or improperly installed which could lead to corrosion and oil leaks. Significant points included in Mr. Shahon's presentation are itemized in Section 8.3.4 of Appendix A. The PowerPoint presentation slides for the FLIR P-600 Infrared Camera System Thermal Imaging technology presentation are included in Appendix J. Additional information about P-600 infrared camera system can be obtained by visiting the FLIR website at http://www.flir.com.

3.3.5   PAL-AT by PermAlert ESP, a Division of Perma-Pipe, Inc.

Mr. Art Geisler of PermAlert ESP, a Division of PermaPipe, Inc. presented PAL-AT. PAL-AT uses Time Domain Reflectometry (TDR) techniques with coaxial sensor cables to detect and locate liquid leaks along pipelines, at pumping/metering stations, and other applications. The main topics of discussion included in Mr. Geisler's presentation are itemized in Section 8.3.5 of Appendix A. The PowerPoint presentation slides for the PermAlert PAL-AT technology presentation are included in Appendix K. Additional information about PAL-AT can be obtained by visiting the PermAlert ESP website at http://permalert.com.

3.3.6   Q&A for Session 3: Vapor Detection and Liquid Sensing PLD and Related Practices

Questions regarding the technologies presented in Session 3 were addressed to the group of presenters. The questions included inquiries about: the ability of sensor cables to detect leaks if wetted in water; the continuity and location of the V-channel installation for LEOS; point type leak detection systems available from PermAlert; the ability for FLIR to see oil in the snow when both are cold and if gas sensitive FLIR can detect vapors over cold crude; the limitations of Tyco's sensing cable for cased crossings in arctic conditions; the ability of the technologies presented in Session 3 to work on cased piping located below grade and not in contact with soil; the longest deployment length of the cable sensing technologies; resetting sensor cables once leaks have been detected; installation of the LEOS diffusion tube relative to the pipeline insulation; ability to use the sensor cable for methanol lines; length of time following a spill that the thermal imaging cameras can be effective; the major deciding factor for installation of an external leak detection product on a crude oil pipeline; experiences of the presenters in working with local regulatory authorities to gain acceptance of the presented technologies; recommended

changes to State of Alaska regulations pertaining to leak detection; accounting based systems; and cost and economics of the technologies presented. A complete list of questions and answers is provided in Section 8.3.6 of Appendix A.

3.4 Session 4 - Fiber Optics PLD and Related Practices

Fiber optics technology uses a basic telecommunications cable to detect changes in temperature and movements to monitor pipeline integrity. Omnisens SA presented the DiTest STA-R Analyzer and Schlumberger Oilfield Services presented the Integriti Pipeline Monitoring System.

3.4.1 DiTest Analyzer by Omnisens SA

Mr. Dana Dutoit of Omnisens SA presented DiTest Analyzer. The Omnisens DiTest Analyzer uses distributed temperature profiles, exhibited by standard fiber optic cables that are installed in close proximity to the pipeline, and Brillouin Optical Time Domain Analysis (BOTDA) technology to detect leaks based on abnormal localized temperature changes. Significant points included in Mr. Dutoit's presentation are itemized in Section 8.4.1 of Appendix A. The PowerPoint presentation slides for the Omnisens SA DiTest Analyzer technology presentation are included in Appendix L. Additional information about DiTest Analyzer can be obtained by visiting the Omnisens SA website at http://www.omnisens.com.

3.4.2 Integriti Pipeline Monitoring System by Schlumberger Oilfield Services

Mr. Alex Albert of Schlumberger Oilfield Services presented Integriti Pipeline Monitoring System. The Integriti Pipeline Monitoring System utilizes distributed temperature, strain, and vibration sensing and a combination of Coherent Rayleigh Noise, Raman and Brillouin Optical Time Domain Reflectometry measurement techniques to detect and locate high pressure gas and liquid leaks. The main topics of discussion included in Mr. Albert's presentation are itemized in Section 8.4.2 of Appendix A. The PowerPoint presentation slides for the Schlumberger Oilfield Services Integriti Pipeline Monitoring System technology presentation are included in Appendix M. Additional information about the Integriti Pipeline Monitoring System can be obtained by visiting the Schlumberger Oilfield Services website at http://www.slb.com.

3.4.3 Q&A for Session 4 - Fiber Optics PLD and Related Practices

A Q&A session was conducted following the two presentations for Session 4: Fiber Optics PLD. The questions inquired about: the cost per kilometer of fiber optic PLD; what are the power requirements to use fiber optics; splicing fiber to install on sections of pipeline; installation options for underground pipelines; the feasibility to retrofit an aboveground multi-phase pipeline; sensitivity of fiber optics to wind noise in aboveground applications; precautions

needed to prevent mechanical damage or vandalism to the PLD system/equipment; single versus multi-mode fiber; intermediate stations needed along long distances of pipelines; signal boosting at stations; sensitivity for a buried crude oil subsea pipeline; and applications that cannot be covered by fiber optics technologies. A complete list of questions and answers is provided in Section 8.4.3 of Appendix A.

3.5 Session 5 - PLD Meter Technology and Related Practices

Micro Motion, Division of Emerson Process Management and PCE Pacific Inc./Emerson Process Management presented leak detection infrastructure technology available for use in PLD systems.

3.5.1   Micro Motion Coriolis Flow and Density Meters by Micro Motion

Mr. Chris Connor of Micro Motion, Division of Emerson Process Management, presented the Micro Motion Coriolis Flow and Density Meters. These meters are used to deliver flow and density measurements for both crude oil and natural gas and provide repeatable performance in multi-phase flow regimes for void fractions as high as 20%.   Significant points included in Mr. Connor's presentation are itemized in Section 8.5.1 of Appendix A. Additional information about Coriolis Flow and Density Meters can be obtained by visiting the Micro Motion website at http://www.micromotion.com.

3.5.2   Smart Wireless and WirelessHart by PCE Pacific Inc.

Mr. Kurt Weedin of PCE Pacific Inc./Emerson Process Management, presented Smart Wireless and WirelessHart 3051S Pressure, 648 Temperature, 702 Discrete, 2160 Vibrating Fork, 708 Acoustic, and 775 Thum meter/transmitter technology. The main topics of discussion included in Mr. Weedin's presentation are itemized in Section 8.5.2 of Appendix A. The PowerPoint presentation slides for the PCE Pacific Inc. Smart Wireless and WirelessHart technology presentation are included in Appendix N. Additional information about Smart Wireless and WirelessHart can be obtained by visiting the PCE Pacific website at http://www.pcepacific.com and the Emerson Process Management website at www.emersonprocess.com/SmartWireless.

3.5.3   Q&A Session 5 – PLD Meter Technology and Related Practices

A Q&A session was held following completion of Session 5 – PLD Meter Technology. Questions received from the attendees included inquiries about: battery life in arctic winter conditions; ability to encrypt the wireless signal for security purposes; safety certifications; and ability for the meters to operate on multi-phase lines for leak detection. A complete list of questions and answers is provided in Section 8.5.3 of Appendix A.

3.6 Conference Participant Evaluation Form Comments

A total of 124 participants, including the ADEC Commissioner, Mr. Larry Hartig, 19 presenters, 9 exhibitors, PLD Technology expert, Moderator, and Shannon & Wilson project manager attended the 2011 PLD Technology Conference. Participant names and name and location of the company or organization represented are listed in Table 3. Of the 124 individuals who attended the Conference, 33 completed the evaluation forms regarding conference satisfaction. 97% of the evaluators rated their overall satisfaction with the Conference as good (48.5%) to excellent (48.5%). Suggested topics for future conferences include:

➢ Leak Prevention.

➢ User or user/supplier presentations. What works, what doesn't?

➢ Pipeline testing protocol and methods, protection systems for pipelines and tank systems, and pipeline integrity and corrosion control.

➢ Any topic that can improve public confidence in pipelines.

➢ How these systems meet regulations and what regulations are met and/or not met.

➢ How to package a system that requires multiple vendors and problems matching them up.

➢ Aboveground tank leak detection technology or similar.

➢ Specific examples of projects that combine the complementary leak detection technologies as successful pipeline management systems.

➢ Customized systems for above ground pipelines and large diameter pipeline systems.

➢ All technologies for natural gas and vapor product pipelines for Arctic environments. These are for future gas development.

➢ Include a session that summarizes State and Federal regulatory requirements for leak detection.

➢ Response related: effective recovery rate calculation for mechanical equipment response and prevention for offshore facilities.

➢ Slides to show detection of oil under ice and snow.

➢ Oilfield operations both upstream and downstream.

➢ A representative installation by company to explain selection, installation, and operation.

➢ An ADEC discussion on their adoption of new technology for compliance options.

➢ An Alaska Oil and Gas Commission discussion synergistically with ADEC and operators to make Alaska oil and gas production profitable again.

> ➢ Economic and financial advantages, government regulations such as leak quantities required for reporting, and penalties and enforcement.

Many of the topics listed above will likely be incorporated into future conferences. A summary of the evaluation forms, including ratings for the individual sessions and additional comments, are provided in Appendix O.

4.0 TECHNOLOGY REVIEW AND APPRAISAL SUMMARY

In the following sections, Shannon & Wilson summarizes the evaluator comments on each of the presentations. These comments were provided by Mr. Randy Allen, UTSI PLD technology expert, and are included in Appendix A.

4.1 Pipeline Leak Detection Technology Users Group Panel Presentations

The first session by the pipeline leak detection technology users group panel was assembled from some of the key pipeline operators present in the state, including ConocoPhillips Alaska, Inc., Alyeska Pipeline Service Company, and Tesoro Alaska Company. The panel discussed a few of the challenges encountered by the various entities operating pipelines in Alaska.

4.1.1 ConocoPhillips Alaska, Inc.

The presentation by ConocoPhillips Alaska, Inc. was a well-rounded explanation regarding how to avoid the most common mistakes and missteps that occur in deployment of a leak detection system that ultimately results in less than desired performance. Efforts to minimize costs by selecting a vendor largely on a cost basis are usually unsuccessful because vendors of products that have limited sophistication know they have to compete in the business arena rather than on a technical basis. Vendors whose products are mature and highly capable are more willing to compete on a technical level, but usually for a reasonable price that reflects the benefits provided by their system. However, there is competition at the highest levels.

To expand on the topic of integration, it is generally important to define the level of integration desired with other systems and produce a functional specification and invitation to bid. Dominant vendors are all adept at integrating their leak analysis results with SCADA systems in order to efficiently draw the controller's attention to the leak alarm. The specification should address any preferences pertaining to the topics presented by ConocoPhillips and listed in Section 8.1.1 in Appendix A. Unlike "concrete and conduit" project specifications, vendors should be expected to take exception where their product does not fully comply with requirements. Vendor proposals should be evaluated based on perceived value and project risk. Pilot projects are a good way to determine a system's capability, especially if the most difficult line is used for the pilot.

4.1.2   Alyeska Pipeline Service Company

The presentation by MH Consulting, representing Alyeska Pipeline Service Company, provided insight into the challenges dealt with by the TAPS leak detection system and how these challenges are expected to grow until, and if, new production increases throughput. While the number of recorded topics is small, a great deal of detail was provided. While the TAPS pipeline leak detection system encounters significant challenges due to hydraulic behaviors that are aggravated by the pipeline operation and terrain, these problems are unique to the TAPS pipeline only with regard to their unique influence on the particular pipeline. Other pipelines in Alaska can encounter similar challenges under typical conditions.

The 1% of daily flow requirement as expressed in the Alaska regulations has a qualifier: *if technically feasible* that eases the low flow problem to some degree. The increased slack-line flow at lower flows will require additional pressure and flow measurements on the pipeline to maintain leak detection performance as good as conditions allow. "Technical feasibility" should not be taken to presume performance limits imposed by inherent characteristics of any particular leak detection product and its implementation. Instead, it should be interpreted to reflect the actual hydraulic characteristics and fluid behaviors matched with the most capable leak detection product for the hydraulic conditions.

4.1.3   Tesoro Alaska Company

The Tesoro Alaska Company presentation provided a detailed example of thermal conditions that can thwart efforts to operate a leak detection system at a high sensitivity level with a low false alarm rate. The jet fuel example illustrates the problem of uncertainty in the linepack due to a significant change in the density of the fluid as it travels to Anchorage.

The comment that the vendor can struggle to understand the fluid dynamics and how to effectively deal with them was significant. Some vendors of products using simple algorithms are not fully aware of their limitations. It is not uncommon for some vendors to explain that temperature is an insurmountable problem even though more sophisticated thermal modeling provided by other vendors can accurately estimate the fluid density profile along the line and minimize false alarms. Tesoro ships gasoline, diesel, and jet fuel to Anchorage in a 10-inch pipeline. A 40°-temperature differential from one end of the line to the other may occur when injecting jet fuel. Even with high quality Coriolis meters, false alarms are a problem. The line goes slack occasionally. Batch changes can cause false alarms. This illustrates the fact that good metering cannot overcome apparently simplistic linepack analysis.

4.2 Meter-Based Solutions Presentations

Meter-based PLD solutions presented during this PLD Technology Conference include several companies that use a combination of measured pressure, flow, temperature, and/or volume for detecting leaks. Meter-based technology has evolved from simple meter comparisons (instantaneous or accumulated flow over an observation interval) to use of more sophisticated algorithms performing linepack analysis in order to properly allocate any observed flow imbalance to a change in pipeline inventory. Meter-based PLD solutions are the dominant methods employed on long transmission lines and require meters at all fluid entry and exit points. The companies presenting technologies included ATMOS International, Inc.; Krohne Oil & Gas; hansaconsult Ingenieurgesellschaft; Vista Leak Detection, Inc.; Telvent USA Corporation; and Siemens. In addition MH Consulting presented a discussion on temperature variations and PLD selection.

4.2.1 ATMOS Pipe® and ATMOS Wave by ATMOS International, Inc.

ATMOS Pipe® is an extremely popular leak detection system due to its record of low false alarms and predictable performance using meter-based mass balance algorithms. The system's strengths include their sophisticated leak probability algorithms, as well as their method of analyzing excursions away from usual quiescent states of the pipeline hydraulics rather than using absolute measurements. The system has been known by the evaluator to replace an early vintage real-time transient model of DEC-PDP (Digital Equipment Corporation-Programmed Data Processor) and its successor after the successor's poor performance rendered it unusable. ATMOS Pipe's performance in this highly transient, but small pipeline network, was deemed acceptable by the operating company and regulators.

While ATMOS Pipe® has a very good record on highly transient systems before their development of a RTTM component, the use of a RTTM's thermal model should improve the system's understanding of the linepack and, therefore, shorten detection time and limit the spilled volumes further. Exploring the options and value of their RTTM module is recommended.

4.2.2 PipePatrol by Krohne Oil & Gas

The evaluator did not have previous experience with PipePatrol on actual projects. However, the performance record provided in the presentation and its underlying technology indicate it would be a worthy competitor for selection on liquid pipelines that operate at elevated fluid temperatures and with temperature declines typical of Alaskan pipelines. The description of bi-directional pipelines with batches of several different products suggests the system expertly handles the adverse influences that would thwart good leak detection performance using less sophisticated meter-based systems. The less capable systems often merely tolerate these

influences by elevating detection thresholds and/or increasing detection time to confirm persistence of the leak evidence. By modeling the pipeline, this system decreases linepack uncertainty and, therefore, has an opportunity to develop confidence in evidence of a leak much sooner than could be done using non-model based systems. The presenter commented that *"You cannot find a leak smaller than you can measure"*. This comment illustrates the point that meter quality determines sensitivity by establishing the best degree of balance accuracy while the algorithm significantly affects detection time by tolerating, or in this case minimizing, linepack uncertainty. This tool is of a class that would handle the temperature issues known to be a problem for other systems in Alaska.

4.2.3   TCS "Tightness Control System" by hansaconsult Ingenieurgesellschaft

This system evolved in a particularly sensitive high consequence area before the term HCA became commonplace. It is particularly suited for use where lines can be shut in tightly and be pressurized for testing. While this particular product has not been traditionally deployed on transmission lines, but rather on complex fuel hydrant networks, it could easily be adapted to support interplant lines and terminals with complex piping. Static pressure testing in its basic form has only recently become a common feature in meter-based systems. This tool offers the potential of extending the sensitivity of any pipeline leak detection capability to its lowest detection level during periods of inactivity. Issues that are expected include the cost of the pressurization system and other infrastructure enhancements, such as control elements, tight valves, proprietary instrument deployment and, in the case of portable operation, the transportation costs. While airport hydrant systems have much more stringent leak detection criteria because of the high hazard environment and sporadic pipeline use allowing time for integrity tests without interrupting operations, they provide an example of what can be achieved if one is really determined to have sensitive leak detection.

An additional benefit of this method is accomplishment of substantially the same verification of pipeline integrity as is provided by hydro-testing, but without the risk associated with the high pressure excursions often required by formal hydro-testing protocols.

Above-ground piping may be more difficult for the pressure step technology because the potentially larger temperature differential between the pipe and its environment may cause more rapid heat flow. However, the benefit of insulation should reduce heat flow much as does the warmed soil around buried pipe. The expected behavior of static testing for each pipeline segment should be established empirically with allowances for seasonal and weather conditions.

4.2.4   LT-100 and HT-100 by Vista Leak Detection, Inc.

Similar to the TCS, this product also is based on the benefit of non-flowing pressurized testing where flow measurement uncertainty is zero because flow is zero. Either of these methods, pressure and volume, could provide integrity verification during periods of pipeline inactivity or upon suspicion of a leak.

4.2.5   SimSuite Pipeline by Telvent USA Corporation

SimSuite is known to be a very detailed model with respect to using parameters that might otherwise be considered insignificant. The modeling technology was developed for use in the nuclear power industry and adapted for pipeline applications.

The model is unique in that there is no standard code base. Instead, an executable file is created from the configuration file. This results in a very fast executable program that can typically be processed four times per second. Early implementations of SimSuite occasionally had difficulty dealing with model errors because the hydraulic errors had to be corrected in the code generator. However, as the product matured, such occurrences became rare to the degree that several pipeline companies have standardized on SimSuite and are very pleased with it.

SimSuite is advertised to exceed API-1149 performance limits. API-1149 results are heavily influenced by the temperature uncertainty used in the API-1149 equations. An accurate metric for temperature uncertainty along the line based on endpoint measurements is difficult to define, especially in environments where fluid temperature varies along the line with the temperature profile dependent on the transit time of the fluid. In such cases, any temperature uncertainty could be very high without the benefit of a thermal model. SimSuite provides such a model and actually reduces uncertainty in the temperature profile along the line. Therefore, a more complete explanation of SimSuite's performance with respect to API-1149 should describe the benefits of their thermal model in reducing the thermal uncertainty that API-1149 would otherwise use in its calculations.

SimSuite offers great opportunities with regard to training controllers as well. It can provide a virtual pipeline on which leaks can be generated without involving the real pipeline. Upset conditions that are to be avoided on the real pipeline can be generated to train the controller to respond appropriately. Managing pipeline assets to prevent Maximum Operating Pressure (MOP) excursions or surge discharges are a common training topic. Controller certification is another common use of the training feature. This tool is also of the class that would handle thermal issues known to be problematic in Alaska.

4.2.6   FUS-LDS by Siemens

The evaluator admits a long-standing suspicion about the fragility of clamp-on ultrasonic meter compared to the reliability of machined spool meters. However, the evaluator also admitted in recent years some companies have deployed clamp-on meters and have standardized on them because they have demonstrated a high degree of reliability. It is believed that methods of ensuring reliable coupling between transducers and the pipe have evolved to a point coupling reliability may be a lesser concern than in the past. In keeping with an interest in erring on the side of caution, the evaluator recommends consulting with the meter vendor regarding deployment methods suitable for the Alaskan climate prior to a commitment, including a program for field tests on pipes that would demonstrate tolerance of the usual sources of decoupling.

The Siemens leak detection system is presumed to be based on the system that was distributed with Controlotron meters before Siemens acquired Controlotron. In any case, the evaluator was pleased to hear the system attempts to estimate the effect of changes in linepack on leak detection performance. However, thermal issues are known to be problematic with other meter-based systems in Alaska where RTTM technology is not used.

The evaluator notes that the general term "model" means to "produce a representation or simulation of[1]" something and, with that broad definition, any effort to assess linepack throughout the line can fall under that terminology. However, it is generally accepted by many in the leak detection community that "modeling" a pipeline and data profiles involves dividing the line into short sections for the purpose of defining homogeneous segments whose characteristics can be applied to solve conservation of energy, mass and momentum equations accurately. In the case of the Siemens leak detection system, the nature of linepack analysis algorithms remains elusive. It is presumed that if their thermal modeling algorithms involved the most detailed solutions typical of RTTM technology, this capability would have been prominently displayed in the slide presentation. Consequently, until further details confirm a sophisticated thermal modeling capability, this system should be deemed more suitable for short lines with limited thermal issues.

The presenter indicated that buffers are provided in order to limit false alarms during packing or unpacking conditions. This statement suggests the use of persistence in distinguishing between a leak and a normal unpacking of the line; a method frequently used to accumulate imbalance data until it overwhelms uncertainty thresholds. The context of the discussion near that description may indicate a strong dependency on persistence, which suggests potentially significant uncertainty in the linepack estimate; thus potentially lengthening the time-to-detect compared to

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[1] http://www.merriam-webster.com/dictionary/model

times offered by RTTM solutions. Until further details are acquired regarding the potential linepack estimation accuracy for potential projects, this solution would be most applicable where the temperature profile is substantially linear or where its shape can be accurately estimated and tracked by native algorithms.

4.2.7   Selecting PLD for a Transmission Pipeline with Temperature Variations as Product Is Conveyed Downstream by MH Consulting

The evaluator regarded this presentation as a clear and concise evaluation of the subject and provided the following discussion of the temperature issue with respect to measurement uncertainty in Section 4.1.2 in Appendix A.

Variations in temperature will have a significant effect on crude oil density. Fluid injection at elevated temperatures with respect to the environment will produce a corresponding ejection of a substantially equivalent, but slightly lesser, volume of higher density fluid. The degree to which incoming and outgoing flows differ is strongly influenced by the temperature difference between injection and delivery sites. During steady-state operations, both the thermal and density profiles along the line are relatively stable, though possibly poorly understood by some leak detection algorithms. During transient operations such as a step change in flow rates, the quiescent state of the thermal profile is disturbed, thus altering heat migration from the oil to the environment. In the case of an increase in flow, the thermal profile is lengthened as fluid travels further down the line while heat is being lost. The thermal profile will become more linear for higher flows. In the case of a decrease in flow, the thermal profile will contract and become more non-linear as more heat is transferred to the environment a shorter distance from the injection point. If the pipeline flow is low enough that the fluid temperature substantially achieves equilibrium with the environment, it becomes impossible to use endpoint measurements to estimate the temperature profile along the line. This is due to the inability to estimate the shape of the curve because thermal equilibrium may have occurred anywhere along the line.

Variations in the thermal profile and changes in its shape are significant problems for meter-based leak detection methods because the natural flow imbalance expected with normal operations will appear to be a shortage (more injected than delivered, or a leak) or an overage (masking a leak) when considering net, or mass, flow through the meters. This can be aggravated by the relatively instantaneous influence of pressure causing the change in flow compared to the longer term thermal effects along the line.

Meter-based methods deal with this problem with varying degrees of success. In cases where fluid injection temperature is substantially the same as delivery temperature, simple algorithms can largely ignore the uncertainty in the temperature profile with reasonable success. Where this

is not the case, the sophistication of the product's method of estimating the temperature profile will determine the leak detection performance.

When considering commercially available leak detection systems for use on a particular pipeline, one should expect long lines or lines with low flow to have very non-linear temperature profiles. Such profiles are difficult to estimate using simple linepack estimation methods, especially under varying flow conditions. Short lines, or lines in which fluid temperature changes vary little from one end to the other, are suitable for most linepack estimation algorithms. When in doubt, it is prudent to err on the side of caution.

4.3 Vapor Detection and Liquid Sensing PLD and Related Practices

Vapor detection and liquid sensing PLD systems have a primary focus on the detection of fugitive product by various means instead of determining the presence of a leak by hydraulic behavior. Several commercial products based on various technologies are becoming common in the pipeline community. Base technologies include vapor detection, liquid hydrocarbon detection, and detection of temperature anomalies indicative of released fluid. Companies presenting their vapor detection and liquid sensing technologies included AREVA NP GmbH, FLIR, Tyco Thermal Controls, and PermAlert ESP, a Division of Perma-Pipe, Inc.

4.3.1   LEOS by AREVA NP GmbH

The LEOS® system has been used in the pipeline industry for a very long time, though not usually on long-haul transmission lines due to its potentially limited range due to diffusion of the hydrocarbon vapor sample and long distances between stations. It's limitation of being slow to acquire a sample prevent its use as a primary leak detection tool looking for leaks of any size. However, when deployed with a meter-based tool, this system can extend sensitivity to the smallest of weepers. It is a good candidate for a role of a secondary leak detection method in Alaska and, if appropriate, on a case-by-case basis as a primary method where metered flow is not an option and the cycle time of the tests are deemed tolerable.

4.3.2   GF-300 Optical Gas Imaging Infrared Camera System by FLIR

The GF-300 Optical Gas Imaging (OGI) Infrared Camera System is a tool best used to determine if fugitive vapors exist in a particular area. The presentation dealt with optical investigation of leak detection and location using thermal imaging cameras. The focus of the presentation was on products somewhat removed from full length pipeline leak detection, but was of great value in a stand-alone operation where investigations were locally focused. The cameras can be mounted on fixed stands in order to monitor gas presence in stations or used in a hand-held mode. They would be applicable for inspecting a pipeline ROW for fugitive natural gas emissions too small to see with the naked eye.

4.3.3   TraceTek 5000 Hydrocarbon Sensor Cable and TT-FFS Fast Acting Fuel Probes by Tyco Thermal Controls

The TraceTek 5000 leak detection system is very suitable for detecting liquid hydrocarbons in localized or medium length applications. As described in the presentation, the only likely false alarms would be legitimate detection of background contamination. This might be problematic for retrofit in older facilities where discarded motor oil was regularly used to control weed growth along fences (an example). An early application of the TraceTek 500 product involved finding a way to extend its range to several miles in length. Since then, the product family has evolved such that support for extended distances is a standard feature.   The 250-meter distance between pull boxes is a bit short when considering manhole covers and the implied structures usually involved where full body access is required. However, such periodic access points facilitate less costly replacement of cable segments after pipe repairs and cleanup, and the manhole covers may simply cover a small vault just below the surface where appropriate cable connections can be made and physically protected from abuse. With the tiny volume of contamination required to cause an indication, this system is capable of providing a leak indication based on a zero-tolerance detection level provided leeway is given for fluid migration from the leak to the cable.

4.3.4   P-600 Infrared Camera System Thermal Imaging by FLIR

The P-600 Infrared Camera System Thermal Imaging technology is focused on detecting liquid hydrocarbons by thermal characteristics that may be in the form of radiant heat or thermal absorption. It is expected that observations will be local except in the case of traveling systems configured for ROW monitoring. It is not expected that fugitive oil will be detected when covered with a blanket of ice or snow. However, ongoing leaks may provide sufficient heat as to create a localized spot where a thermal signature may be seen as different from surrounding areas even though visible differences are not yet significant. The method is especially useful for facility monitoring or ROW examination in conjunction with a meter-based system.

4.3.5   PAL-AT by PermAlert ESP, a Division of Perma-Pipe, Inc.

PAL-AT would be suitable for deployment over high consequence areas where cable characteristics match the environment in which it is deployed. As with other cable-based sensors, a plan to ensure a leak contaminates the cable must be developed and executed. Close cooperation with the vendor to engineer an appropriate deployment plan is recommended. Particular questions to address would be wet cable operation (noting the wet cable startup comment), the effect of ice formation in or around the cable, and splicing methods in the event a leak is detected and repairs are needed. Potential users should request a proposal based on a complete description of the pipeline, its environment characteristics, and performance goals.

The proposal should describe performance limitations and their causes, as well as a deployment strategy that addresses regional and seasonal issues that may dictate particular installation methods.

4.4 Fiber Optics PLD and Related Practices

Fiber optics technology uses a basic telecommunications cable to detect changes in temperature and movements to monitor pipeline integrity. It was not very long ago when there was a great deal of information available about the potential of fiber optic technology in pipeline integrity monitoring applications. However, during the infancy of the technology, finding commercial products that were capable of exciting the fiber in some manner, interpreting any results, and generating useful information was a challenge. Those days are over now that commercial products exist that can collect data that can be easily interpreted and associated with normal or leaking conditions. There remains a need to engineer a particular solution using the commercial products deployed in a way that a leak will influence the fiber optic cable and, therefore, provide evidence of the leak. Omnisens SA presented the DiTest Analyzer and Schlumberger Oilfield Services presented the Integriti Pipeline Monitoring System.

4.4.1 DiTest Analyzer by Omnisens SA

It was not that many years ago when the potential of fiber optic technology to measure temperature along its length was demonstrable in the laboratory. In the early days of the development of the technology, distances between stations limited its practical use and there were no commercially available products that supported pipeline applications. Those products that did exist were not as easily integrated with external systems as they are now.

The technology has matured greatly and Omnisens produces commercially available products that are easily configurable to recognize pipeline leaks any time a leak would create a temperature anomaly, either by direct contact of fluid with the cable or by enhanced heat flow from the pipe to the cable through soil saturated by oil. It is noteworthy that information of interest is not the actual temperature of the cable, but temperature anomalies in the thermal profile of the cable. Measurement resolutions down to one meter, with peak and average temperatures collected for each segment, provide an ability to detect leak conditions and monitor the spread of fluid in the trench at the leak site.

Fiber optic technology can provide primary leak detection services in multi-phase flow conditions where leakage of either gas or liquid contents would affect the cable. It may be especially useful where meters are expected to be inaccurate due to multi-phase flow and where longer multi-phase lines are subject to fluid behaviors such as phase change and slugging that thwart meter-based algorithms. It is also an excellent secondary method where meter-based solutions are deployed as a primary leak detection method. Given the requirement of a one

percent (1.0%) of daily throughput and meter accuracy limitations, this method may provide greater sensitivity than is possible using meter-based tools on high throughput lines. In this case, accurate leak location is a secondary benefit of the technology.

Pipeline operators considering the deployment of fiber optic technology must work with the vendor to develop a good deployment strategy that will accomplish the operator's leak detection goals. The technology is not recommended on existing buried pipelines due to the excavation risk to the pipeline. However, it is recommended for existing above ground pipelines. Another benefit of this technology can be a high speed communications network for both data and voice applications.

4.4.2   Integriti Pipeline Monitoring System by Schlumberger Oilfield Services

The Integriti Pipeline Monitoring System presentation confirmed the maturity of fiber optic technology and demonstrated its applicability in pipeline leak detection and in pipeline security monitoring. The foundation of the Schlumberger products is based on the same underlying technology as was described in the previous Omnisens presentation. Schlumberger, however, appears to have fast tracked their product deployment into their entire spectrum of services they traditionally support. That is not intended to suggest a less than deliberate focus on each application, but rather to acknowledge that Schlumberger has a long history of involvement in numerous activities where fiber optic technology can be applied. This has given them practical experience in a wide variety of implementations that are of interest in Alaska.

Schlumberger's fiber optic technology is also suitable as a primary method for flow lines where meter-based techniques are impractical and multi-phase pipelines where meter-based solutions are not expected to perform well. Their system is also applicable as a secondary leak detection method to complement meter-based solutions.

4.5 PLD Meter Technology and Related Practices

These presentations focused on leak detection infrastructure component technology, such as Coriolis meters and transmitter technology. Micro Motion and PCE Pacific Inc., both Divisions of Emerson Process Management presented several meters available for use in PLD systems.

4.5.1   Micro Motion Coriolis Flow and Density Meters by Micro Motion

Coriolis meters have in recent years gained market share because of the maturity of the technology and increasing capacity to cover larger pipelines. Their overall benefits are such that some companies standardize on them for custody transfer applications, especially where flow rates vary. While these meters are a very good fit for pipeline leak detection, it is important to remember that the uncertainty related to flow measurement at the meter location pales in

comparison to linepack uncertainty as flow imbalances are measured. It is the linepack uncertainty that leads to a high false alarm rate or masking of real leaks. As the presenter indicated, good metering is the foundation of meter-based leak detection. However, good meters cannot substitute for effective linepack analysis algorithms. Installing high quality meters on lines whose operations have linepack uncertainty issues will not compensate for limited algorithm sophistication.

Coriolis meters are growing in popularity in the lower forty-eight states because their reputation for reliable accurate measurement is good. It is important to determine whether the available leak detection algorithm would perform better using volumetric measurement or mass measurement. Short lines with changing injection temperatures due to batched operation may require volumetric data since the mass in each barrel injected can vary as batch sources and corresponding temperatures are switched. With a short line, balancing barrels by volume, if this problem exists, could be superior to balancing by mass since the mass of an injection barrel and discharge barrel may differ significantly even though the volumes match. RTTM technology handles this issue natively and benefits greatly from accurate flow measurement.

4.5.2   Smart Wireless and WirelessHart by PCE Pacific Inc.

The Smart Wireless and WirelessHart products described in this presentation are applicable on any pipeline project, subject to review of their environmental specifications with respect to the expected operating environment. The wireless transmitters are interesting in several ways. However, long scan intervals of thirty-two seconds for a ten-year battery life are not desirable in a leak detection system. It is preferable to have scan frequencies at around or under five-second intervals. Consequently, power may need to be distributed to transmitters in order to avoid occasional battery replacement. If power must be distributed, wired communication infrastructure can be installed at the same time. It is also necessary to verify the wireless data communication system will operate during adverse weather conditions.

5.0   CONCLUSION AND RECOMMENDATIONS

Each of the Conference presentations described PLD technologies and/or practices to accomplish leak detection in Alaska. The following sections discuss the applicability of each of the PLD technologies and/or practices presented at the Conference for use on crude oil transmission pipelines, multi-phase flow lines, and facility oil piping in Alaska. Specific operations, geographical locations, or physical environments where the PLD systems could be applied are identified. PLD technologies that may significantly enhance leak detection performance on existing pipelines are discussed. Recommendations for pipeline leak detection system selection and design are also provided.

5.1 Applicability of PLD Technologies Presented at Conference

The PLD technology and practices providers discussed commercially available products that could be considered for deployment on petroleum pipelines in Alaska. In general, the applicability of the PLD technology or practice depends on the specific characteristics of the individual pipeline being considered including fluid/chemical properties; pipeline length; existing or new underground or aboveground installation; flow rate patterns; temperature variations; measurement systems and equipment currently in use; desired sensitivity, leak detection time, leak location capability, accuracy of leak volume estimates, and adaptability of a given technology to routine and non-routine activities; and the expectations of the operators using the system.

The PLD technologies and practices presented at the Conference can be deployed individually or combined and deployed as integrated tools within a system, with appropriate engineering design, to significantly improve leak detection performance on petroleum pipelines in Alaska. Potential technologies are discussed below.

5.1.1   Crude Oil Transmission Pipeline Leak Detection Systems

CPM leak detection technology or meter-based PLD solutions presented during the Conference include several companies that use a combination of measured pressure, flow, temperature, volume, and/or acoustics for detecting leaks. Meter-based PLD solutions are the dominant methods employed on long crude oil transmission pipelines and require, at a minimum, meters at all fluid entry and exit points. Meter-based solutions used on crude oil transmission pipelines in Alaska have a record of being thwarted by thermal issues. Two commercially available products presented at the Conference, PipePatrol and SimSuite Pipeline, are Real-Time Transient Models (RTTMs) that can significantly improve leak detection performance by modeling heat transfer and the density profile of the fluid in the pipeline.

One meter-based tool described in the Conference, ATMOS Pipe®, uses statistical processes to determine the probability of a leak based on behavior "learned" during configuration. ATMOS Pipe® has been tested on a North Slope pipeline and was shown to significantly improve leak detection performance. ATMOS Pipe® is reported to have shortened detection time in a fluid withdrawal test from fourteen hours to under one hour compared to the incumbent system on the pipeline.

The Siemens FUS leak detection system is deemed suitable for short lines with limited thermal issues.

External leak detection technologies such as LEOS, TraceTek, PAL-AT, DiTest Analyzer, and Integriti may be applicable as a secondary leak detection method to extend leak detection

sensitivity or shorten detection time. These leak detection technologies do not estimate leak rates and, therefore, must be combined with a meter-based solution for volume loss verification. These external technologies have the potential to significantly limit released fluid volumes and have an added benefit of accurate leak location. With the relatively short range possible with LEOS, it should not be considered suitable for long crude oil transmission pipelines. TraceTek and PAL-AT are better suited for shorter segments of pipelines while Ditest Analyzer and Integriti fiber optics solutions can be deployed on pipelines up to several hundred miles long.

The FLIR P-600 Infrared Camera System Thermal Imaging technology is focused on detecting liquid hydrocarbons by thermal characteristics that may be in the form of radiant heat or thermal absorption. Fixed wing and helicopter-mounted P-600 Infrared Camera traveling systems can be configured for weekly aerial surveillance. The FLIR GF-300 OGI Infrared Camera System is a tool best used to determine if fugitive vapors exist in a particular area. The cameras are hand-held devices especially useful for facility monitoring (valves, flanges, etc.) or on-the-ground surveillance of pipeline right-of-ways accessible by vehicle.

Static pressure or volume tests, as discussed by hansaconsult with TCS and Vista Leak Detection with LT-100 and HT-100, are particularly suited for use where liquid can be shut in tightly and pressurized for testing. Depending on the diameter and length of the transmission line, either of these methods, pressure and volume, may provide integrity verification upon suspicion of a leak.

As important as detecting a leak is, the controller's response is equally critical. Training programs should be developed around actual fluid withdrawals in order to verify that controllers recognize and respond to leaks appropriately.

5.1.2   Multi-Phase Flow Line Leak Detection Systems

Flow verification for multi-phase flow lines is problematic with measurement errors up to plus or minus twenty percent (+/- 20%). Multi-phase flow meters are improving but do not have nearly as high an accuracy specification as seen for single-phase meters. Separation of multi-phase flow at the wellhead, if possible, would provide a significant improvement in leak detection performance where separate pipelines are used for each fluid being transported.

The accuracy of RTTM is limited by multi-phase flow measurement accuracy and uncertainty in condensate formation and expulsion. Telvent indicated that SimSuite has been deployed on a number of flow lines. ATMOS Pipe® is installed on two multi-phase pipelines in Russia and may be installed on a multi-phase project in Brazil where as much as $500,000 may be spent per flow meter. These meter-based solutions rely on accurate flow measurements for their leak detection sensitivity and detection time and, therefore, must be combined with a complementary

method that extends sensitivities and shortens detection times. Meter-based solutions may be worthy of deployment on flow lines as a secondary system to verify approximate volume loss.

External leak detection technologies such as LEOS, TraceTek, PAL-AT, DiTest Analyzer, and Integriti can provide primary leak detection services in multi-phase flow conditions where leakage of either gas or liquid contents would affect the cable. Accurate leak location is a secondary benefit of these technologies.

Static pressure or volume tests, as discussed by hansaconsult with TCS and Vista Leak Detection with LT-100 and HT-100, are particularly suited for use where pipelines can be shut in tightly and pressurized for testing. For multi-phase fluid lines, gas would need to be removed from the pipeline and a single-phase fluid would need to be used for the test.

Double-wall pipe with interstitial monitoring using such methods as LEOS, TraceTek, or PAL-AT, have the potential of combining fluid containment with sensitivity far greater than provided by usual leak detection methods.

The P-600 Infrared Camera System Thermal Imaging technology can be configured for fixed wing and helicopter-mounted traveling systems to provide weekly aerial surveillance of flow lines. The GF-300 OGI Infrared Camera System is especially useful for facility monitoring (valves, flanges, etc.) or on-the-ground surveillance of flow line right-of-ways accessible by vehicle.

5.1.3   Facility Oil Piping Leak Detection Systems

The same pipeline leak detection technologies deployed on crude oil transmission pipelines and multi-phase flow lines are applicable to facility oil piping. The selection criteria are the same but facility oil piping is typically much shorter in length than crude oil transmission pipelines and multi-phase flow lines. In selecting the appropriate PLD technology for facility oil piping, operators need to consider the specific characteristics of the individual piping.

5.2 Specific Operations, Geographic Locations, and Physical Environments

The commercially available products presented at the Conference can potentially be deployed as tools, with appropriate engineering design as discussed in Section 5.4, in an integrated pipeline leak detection system to enhance leak detection performance on petroleum pipelines in Alaska. Table 4 provides examples of specific pipeline operations where the pipeline leak detection technologies can be considered for deployment as primary, secondary, or tertiary tools to monitor for leaks or to perform pipeline integrity tests upon suspicion of a leak.

External leak detection technologies may be suitable as a primary or secondary method for environmentally sensitive areas and/or a High Consequence Area (HCA). Environmentally sensitive areas may be pipelines or flow lines constructed subsea, under or over water bodies, within threatened or endangered species habitat, in aquifer recharge zones, etc. HCAs are defined in Title 49 Code of Federal Regulations (CFR) Part 195.903 as areas where transmission pipeline accidents could have a greater consequence to health and safety or the environment.

LEOS, TraceTek, PAL-AT, DiTest Analyzer, and Integriti are highly sensitive to small amounts of contaminant, potentially in the range of teaspoons, with the necessary direct contact. These technologies can be deployed in environmentally sensitive areas and HCAs as a secondary system combined with a meter-based solution for crude oil transmission pipelines and as a primary system combined with a meter-based solution for flow lines.

Installation of double-wall pipe in environmentally sensitive areas and/or HCAs provides fluid containment with leak detection sensitivity far greater than usual methods. Double-wall pipe interstitial monitoring can be accomplished using LEOS, TraceTek, or PAL-AT.

5.3 Proven PLD Technology Breakthroughs

A PLD technology breakthrough may be described as the development of a new product or practice that significantly enhances leak detection performance. The pipeline leak detection technologies and practices represented at the 2011 PLD Technology Conference have been or are currently being used somewhere on Alaskan pipelines. Therefore, none of the products are considered breakthrough technologies. Implementation of several of these technologies and/or practices, however, can significantly enhance leak detection performance on existing pipelines.

RTTM technology can provide performance gains compared to simpler meter-based solutions widely used on Alaska pipelines. Configuration tools, self-tuning algorithms, and instrument quality assessment features decrease the complexity of RTTM systems while providing optimum performance with less configuration effort. RTTM minimizes uncertainty in the linepack by modeling heat transfer and the density profile of the fluid in the pipeline and has been successfully deployed by pipeline companies whose operations include highly transient hydraulic behavior that would thwart lesser tools. RTTM technology has successfully been deployed on some Alaska pipelines for many years, specifically TAPS. Implementation of RTTM can significantly enhance leak detection performance for pipeline companies whose operations include highly transient hydraulic behavior, low flow, and/or temperature variations.

ATMOS Pipe® uses statistical processes to determine the probability of a leak based on behavior "learned" during configuration. It has been tested on a North Slope pipeline, and is reported to have shortened detection time in a fluid withdrawal test from fourteen hours to under one hour compared to the incumbent system on the pipeline. Implementation of ATMOS Pipe® can

significantly enhance leak detection performance for pipeline companies whose operations include highly transient hydraulic behavior and/or temperature variations.

External sensing technologies, such as LEOS, TraceTek, PAL-AT, DiTest Analyzer, and Integriti, are highly sensitive to small amounts of contaminant, potentially in the range of teaspoons, but require an engineering effort to ensure a leak will provide evidence of its existence to the sensor. Implementation of external sensing technologies can significantly enhance leak detection performance for pipeline companies whose operations include multi-phase flow, highly transient hydraulic behavior, and/or temperature variations.

5.4 System Selection and Design

Selecting the right leak detection product or products is critical for successful detection of leaks at the lowest feasible detection threshold and shortest detection time. Leak detection performance limitations associated with temperature are often stated as reasons why achievement of mandated performance metrics, described in 18 AAC 75, are not feasible. Based on presentations heard during the 2011 Conference it is clear that more sophisticated tools offer advantages over tools that are routinely thwarted by temperature uncertainties along Alaskan pipelines.

Selection of leak detection products should be a cooperative effort involving the pipeline operator and potential suppliers of leak detection products. The first consideration by purchasers that should be made is that the vendor's salesman may not be aware of the inherent limitations of his own product, or that completion of the sale is paramount over the customer's satisfaction with product performance. In many cases, the salesman holds a pessimistic view of their competition's product capabilities compared to those of his own product, and often with no actual familiarity with competing products. Mr. Allen explained that one vendor's salesman declared his product's usual sensitivity to be very good compared to that of a competing product. His experience was that the competing product's performance was twelve times better than the competing salesman claimed. No vendor claims about competitive product performance should be taken seriously without confirmation from unbiased sources. It is the pipeline company that must become familiar with technology options in order to make informed decisions.

Future standards of due diligence may include the ability to limit releases to a small volume; thus making a combination of a meter-based solution and a fugitive oil detection system necessary. Clean-up costs and penalties may already justify deployment of primary and secondary systems, especially in cases where fugitive oil may be spread widely by migration via waterways and irregular terrain. With this in mind, the first question to answer involves whether such a system architecture should be considered. The second should address what combinations of technologies broaden the performance window rather than simply duplicate the same window.

Once a general approach is defined, vendors such as those who presented papers at the Conference should be contacted for assistance in developing a strategy that maximizes leak detection performance and integration with other systems such as SCADA using their products. Vendors who did not attend the Conference, but who offer products based on similar technologies to those described during the Conference should also be considered. Initial performance projections should be completed prior to development of a short-list of products deemed worthy of further consideration. Buyers should be very wary of performance claims of a product with little or no consideration of the project details such as pipeline, fluid, and environmental characteristics. Any such claims should be justified by an explanation regarding why particular details are not important. It is prudent to assume an issue that is considered unimportant is also not handled well. Examination of the product's performance track record where the issue is known to exist should confirm any claims that the issue has no significant adverse impact on performance. Care should be taken to ensure aggravating factors such as low flow rates or slack line appear in the experience used to confirm the issue is unimportant on a pipeline substantially similar to the target pipeline.

Each vendor should be expected to ask for pertinent project details that would influence the successful application of their technology. Again, failure to address potential obstacles to successful deployment should be met with suspicion. Working with multiple vendors with similar products to define product differences can often provide insight regarding issues inherent in that class of leak detection product regardless of the vendor or product. Such competition can provide the buyer with information from one vendor that is critical for successful deployment of either vendor's product, or it can highlight product or technology deficiencies. Information learned during product evaluation can be used in the bid specification either as an alert to the bidder that an issue exists, or as a warning that the solution will have to address the issue successfully; subject to the bidder's proposed solution in that area.

Application of different technologies involves different deployment strategies and in some cases different configuration information. For example, modeling fluid thermal behaviors requires heat transfer characteristics of the environment as well as fluid thermal properties. Since river crossings can have a significant effect on fluid temperature at a faster rate than would occur on land, it is prudent to measure temperature on either side of the river as close as possible in order to properly characterize the land-water-land thermal properties. Vendors who will need this information are adept at defining applicable parameters by known soil types or empirically. However, buyers must make the presence of such issues known while products are being evaluated so that they can be considered in performance projections.

It has been observed that bid specifications are very important in the project planning process. A bid specification written in a manner that requires all bidders to declare and explain any exceptions taken to requirements is necessary to negotiate a binding contract. Such a

specification should present all project characteristics known to be important to successful deployment of the target technology. For example, typical injection fluid and soil temperatures as well as delivery point temperatures are important in designing a deployment strategy for a system based on fiber optic Distributed Temperature Sensing (DTS) technology. Having a fluid temperature the same as the environmental temperature would thwart successful use of DTS methods because a leak would not result in a temperature anomaly. Flow rate and pressure would be of no interest to DTS provided reasonable thermal parameters are applicable for all operational conditions. A meter-based solution would likely use such endpoint thermal measurements, but they would be less critical in determining if the solution would work conceptually. Instead, pressures and flows would be of interest to determine if leaks of various rates could be detected based on pressure/flow anomalies.

The bid specification, in addition to making bidders aware there is competition, is the opportunity for purchasers to define the scope of their project to a degree that expensive change orders cannot be justified based on the vendor being unaware of some aspect of the purchaser's operation during the bid process. It is also an opportunity to request guidance from the vendor to define the infrastructure necessary to achieve specified performance goals. Eliminating justification for failure to meet performance predictions is a significant benefit of a delivery contract that includes the vendor's proposal in response to the bid specification. Specifications are also important in conveying responsibility for integration with SCADA systems.

Determining which leak detecting product(s) should be deployed on a given pipeline in order to achieve the best possible performance can be a time-consuming process. For small operations using a consulting firm familiar with the technologies and processes can be attractive because they become a temporary and skilled extension of the engineering team. Using internal staff to research various options and executing the project in-house can result in a well-trained support staff as the system is commissioned. In either case, expectations that a pipeline may leak and cleanup will be necessary, and 18 AAC 75 requirements, drive the search for the best available leak detection technology.

TABLE 1 - PIPELINE LEAK DETECTION TECHNOLOGY PROVIDER CONTACT INFORMATION

Technology Provider Name	Technology Name	Previous Use	Website	Company Contact	Contact Email	Contact Phone	Technology Description	Exhibit Hall
AREVA NP GmbH	LEOS	Inside Alaska	http://www.areva-diagnostics.de/en/	Dr. Walter Knoblach	walter.knoblach@areva.com	49-9131-90092367	LEOS monitors for chronic leaks by air sampling with permeable plastic "sensor tube" that is installed with the pipeline. Leakage substance is collected inside sensor tube by through-wall diffusion.	no
ATMOS International, Inc.	ATMOS Pipe and ATMOS Wave	Inside Alaska	http://www.atmosi.com	Michael Twomey	mike.twomey@atmosinc.com	714-907-1366	ATMOS Pipe uses learned volumetric flow difference for a pipeline and compares it to the current flow difference to determine probability of a leak and ATMOS Wave detects the negative pressure waves associated with the onset of a leak.	yes
FLIR	GF-300 Series Cameras	Inside Alaska	http://www.flir.com	David Shahon	david.shahon@flir.com	800-853-8331	FLIR – GF-300 Optical Gas Imaging (OGI) is an Infrared Camera system that is tuned to "see" volatile organic compound (VOC) gas vapors. Leaking vapors from oil and gas filled pipes are "visible" with the GF-300 Camera.	yes
FLIR	P-600 Camera	Inside Alaska	http://www.flir.com	David Shahon	david.shahon@flir.com	800-853-8331	FLIR – P-600 Infrared Camera System detects leaks based on temperature differences in the surrounding area. Oil on water looks different with an IR camera. Temperature differences on insulated pipe create an anomaly or non-uniformity indicating insulation is wet or improperly installed which could lead to corrosion and oil leaks.	yes
hansaconsult Ingenieurgesellschaft	TCS "Tightness Control System"	Inside Alaska	http://www.hansaconsult.com	John Birnie	jbirnie@hansaconsult.com	603-879-0388	TCS "Tightness Control System" Pressure-Step and Pressure Temp Method Leak Detection System is a highly accurate static leak detection test and Kleopatra is a simulation software for dynamic leak detection.	yes
Krohne Oil & Gas	PipePatrol Leak Detection and Localization System (fka Gallileo)	Outside Alaska	http://www.krohne.com	Daniel Vogt	d.vogt@krohne-oilandgas.com	31-76-711-2096	PipePatrol is a Real Time Transient Model Leak Detection System with unique signature analysis to prevent false alarming on pipelines containing crude oil, natural gas, refined hydrocarbons, liquefied gases and supercritical gases but not multiphase.	yes
MH Consulting	Life Cycle Project Management	Inside Alaska	http://mhcinc.net	Morgan Henrie	mhenrie@mhcinc.net	907-229-5469	Selecting a PLD on a crude oil transmission pipeline with temperature variations as product is conveyed downstream.	yes
Micro Motion, Division of Emerson Process Management	Micro Motion Coriolis Flow and Density Meters	Inside Alaska	http://www.micromotion.com	Chris Conner	Chris.Connor@emerson.com	281-610-7271	Micro Motion Coriolis Flow and Density Meters are used to deliver accurate, repeatable flow and density measurements for both crude oil and natural gas and provide good, repeatable performance in multi-phase flow regimes for void fractions as high as 20%.	yes
Omnisens SA	Ditest LTM	Inside Alaska	http:// www.omnisens.com	Dana Dutoit	dana.dutoit@Omnisens.com	953-236-4422	DiTEST STA-R Analyzer uses Brillouin Optical Time Domain Analyzer (BOTDA) to determine leak time and location by evaluating light scattering that occurs in fiber optic cables positioned along pipeline.	yes

TABLE 1 - PIPELINE LEAK DETECTION TECHNOLOGY PROVIDER CONTACT INFORMATION

Technology Provider Name	Technology Name	Previous Use	Website	Company Contact	Contact Email	Contact Phone	Technology Description	Exhibit Hall
PCE Pacific Inc. / Emerson Process Management	Smart Wireless; WirelessHart; 3051S Pressure Transmitter, 648 Temperature Transmitter, 702 Discrete Transmitter, 2160 Vibrating Fork Transmitter, 708 Acoustic Transmitter, 775 Thum	Inside Alaska	http://www.pcepacific.com / www.emersonprocess.com/SmartWireless	Keith Weedin	keith.weedin@pcepacific.com	907-243-3833	WirelessHart products are used to provide pressure, temperature and flow measurements to support leak detection from remote sensors without need for cabling, power or communication infrastructure.	yes
PermAlert ESP, a Division of Perma-Pipe, Inc.	PAL-AT	Inside Alaska	http://permalert.com	Art Geisler	art.giesler@permapipe.com	817-239-2234	PAL-AT System uses a coaxial cable connected to a microprocessor based panel capable of continuously monitoring a sensor string. Liquid hydrocarbons can penetrate the coaxial cable. The control panel uses Time Domain Reflectometry techniques to locate and detect when a leak, break or short occurs in the coaxial cable.	yes
Schlumberger Oilfield Services	Integriti Pipeline Monitoring System	Outside Alaska	http://www.slb.com	Alastair Pickburn	APickburn@slb.com	44-1794-529567	Integriti Pipeline Monitoring System utilizes distributed temperature, strain and vibration sensing using a combination of Coherent Rayleigh Noise, Raman and Brillouin Optical Time Domain Reflectometry measurement techniques to detect and locate high pressure gas and liquid leaks.	no
Siemens	Sitrans FUH1010 Ultrasonic Meters	Inside Alaska	http://www.sea.siemens.com	Jim Doorhy and Jaye Johnson	james.doorhy@siemens.com and jaye.johnson@siemens.com	631-231-3600 x 1258	Clamp-on transit-time ultrasonic flowmeters use patented WideBeam™ technology to induce an axial sonic wave in the pipe wall for leak detection.	yes
Telvent USA Corporation	SimSuite Pipeline	Inside Alaska	http://www.telvent.com	Michael Tankersley and Kelly Doran	mike.tankersley@telvent.com and kelly.doran@telvent.com	410-910-1270	SimSuite Pipeline is a two-phase, non-thermal equilibrium Real Time Transient Model. It has separate dynamic mass, momentum and energy balances for each phase, and provides complete simulation of pipeline systems including pump stations, compressor stations, injection/delivery stations, tank farms, valves and control logic.	yes
Tyco Thermal Controls	TraceTek 5000 Hydrocarbon Sensor Cable, TT-FFS fast acting fuel probes, TTSIM Sensor Interface and TTDM-128 Alarm Panels	Inside Alaska	http://www.tracetek.com or http://www.tycothermal.com	Ken McCoy	kmccoy@tycothermal.com	650-474-4785	TraceTek uses sensor cables and probes that interact with spilled liquid hydrocarbons producing electrical changes that are monitored by sensor interfaces and alarm panels to detect leaks and leak location.	yes
Vista Leak Detection, Inc.	LT-100 and HT-100	Outside Alaska	http://www.vistaleakdetection.com	Doug Mann	dmann@vistald.com	509-737-1380	LT-100 and HT-100 are thermally compensated, dual pressure, precision volumetric tests for leak detection on pipeline segments under static conditions. Leak condition is determined by comparing volume data at the conclusion of the test period.	yes

TABLE 2 - OTHER PIPELINE LEAK DETECTION TECHNOLOGIES

Technology Provider Name	Technology Name	Website	Technology Description
Acoustic Systems Incorporated	WaveAlert	www.wavealert.com	WaveAlert uses sensitive acoustic sensors situated at the ends of the pipeline and some intermediate valve sites to detect leaks and determine leak location.
Asel-Tech	ILDS	www.asel-tech.com	Asel-Tech Integrated Leak Detection System (ILDS) combines two detection techniques defined by API 1130; acoustic (negative pressure wave) and mass balance technologies.
Auspex (fka EnviroPipe Applications)	Leak Track 2000	www.leaktrack2000.com	Leak Track 2000 (LT2000) uses deviation methodology to detect leaks. Deviation, includes mass balance/line pack, flow deviation, pressure wave analysis and other monitored data.
Avateq	WaveControl	www.avateq.com	WaveControl leak detection system is based on the principle of detection and identification of pressure waves that occur in pipelines during leaks.
Chelsea Technologies Group	Sub-Sea PLD	www.chelsea.co.uk	Chelsea's pipeline leak detection system finds leaks in sub-sea pipelines by sensing the fluorescence of leaking hydrocarbons or, for pipeline commissioning, by introducing fluorescent dyes (such as Rhodamine, Fluorescein or Agma EP1186/MIS). The system is extremely sensitive and is capable of detecting leaks at levels as low as 1 part per million (ppm) in sea water.
EFA Technology	LEAKNET™	www.efatech.com	LEAKNET™ is a fully integrated software/hardware product that includes the patented Pressure Point Analysis (PPA)™ algorithm and an operationally independent (and proprietary) mass balance system with dynamic line pack compensation called MassPack™.
Energy Solutions International (fka Modisette Assoc, LICEnergy Inc., and Simulutions)	PipelineManager/ LeakWarn	www.energy-solutions.com	ESI uses Real Time Transient Models to simulate operating conditions and show the operator and others a complete hydraulic picture of the pipeline, including the position of all batches.
Multi Phase Meters AS	Multiphase Meters	www.mpm-no.com	MPM multi-phase flow meters can measure oil, gas and water without separation using radio frequencies and other technologies to create a three dimensional image of flow through multiple planes that measure the individual parts.
Praxair (fka Tracer Research)	Tracer Tight and Seeper Trace	www.praxair.com	Praxair's tracer chemicals are added directly to the product in the pipeline or in water during hydrotesting. Samples are collected along the pipeline and analyzed. The detection of the tracer chemicals indicates leakage.
Pure Technologies	SmartBall®	www.puretechnologiesltd.com	The SmartBall® device consists of an instrumented aluminum core in a urethane shell slightly smaller than the inside diameter of the pipeline. The ball rolls along with the flow in the pipeline using a range of instrumentation, including an acoustic data acquisition system that listens for leaks as the ball travels through the pipeline.
Smart Pipe	Smart Pipe	www.smart-pipe.com	Smart Pipe is a double-walled HDPE pipe tight fit liner simultaneously manufactured and installed (using trenchless technology) in up to 50,000 feet of an underground pipeline without disruption of the surface areas covering the pipeline except for a small opening at the entry and exit points of the pipeline section being lined. Fiber optic sensors in the interstitial space monitor leak detection.
SPS GL Noble Denton [fka Stoner Pipeline Simulator (SPS)]	Leakfinder	www.gl-nobledenton.com	Leakfinder uses "Active Modeling" to dynamically modify leak detection thresholds to ensure fast and accurate leak detection and location under all operating conditions, while minimizing potential false alarms.
Worley Parsons (fka Colt Technologies)	Lineguard	www.worleyparsons.com	LINEGUARD is a field-proven, innovative approach to modeling the transient behavior of liquid pipelines and provides an accurate, robust, model-assisted, material-balance leak detection system.

TABLE 3 - PIPELINE LEAK DETECTION CONFERENCE PARTICIPANTS

Last Name	First Name	Function	Participating Company or Organization	City	State Province	Country
Hartig	Larry	Commissioner - Opening Remarks	Alaska Department of Environmental Conservation	Juneau	Alaska	USA
Munson	Dianne	Work Group	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Saengsudham	Surath	Work Group	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Pexton	Scott	Work Group	Alaska Department of Environmental Conservation/Spill Prevention and Response	Anchorage	Alaska	USA
Allen	Randall	Evaluator	UTSI International Corporation	Friendswood	Texas	USA
Jessen	Julie	Moderator	HDR Alaska, Inc.	Anchorage	Alaska	USA
Terry	Tim	Organizer	Shannon & Wilson, Inc.	Anchorage	Alaska	USA
Alzheimer	David	Presenter	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Henrie	Morgan	Presenter	MH Consulting, Inc.	Anchorage	Alaska	USA
Moore	Gillus	Presenter	Tesoro Alaska Company	San Antonio	Texas	USA
Nicholas	Ed	Presenter	Nicholas Services	Harrisonburg	Virginia	USA
Knoblach	Walter	Presenter	AREVA NP GmbH	Erlangen	Bayern	Germany
Albert	Alex	Presenter - Exhibitor	Schlumberger	Houston	Texas	USA
Birnie	John	Presenter - Exhibitor	Hansaconsult	Alton	New Hampshire	USA
Connor	Chris	Presenter - Exhibitor	MicroMotion	Boulder	Colorado	USA
Doran	Kelly	Presenter - Exhibitor	Telvent USA Corporation	Columbia	Maryland	USA
Dutoit	Dana	Presenter - Exhibitor	Omnisens SA	Morges	Switzerland	Switzerland
Giesler	Art	Presenter - Exhibitor	PermAlert ESP, a Division of Perma-Pipe, Inc.	Niles	Illinois	USA
Mann	Doug	Presenter - Exhibitor	Vista Leak Detection	Richland	Washington	USA
McCoy	Ken	Presenter - Exhibitor	Tyco Thermal Controls	Menlo Park	California	USA
Murphy	Paul	Presenter - Exhibitor	Siemens Industry, Inc.	Atascadero	California	USA
Shahon	Dave	Presenter - Exhibitor	FLIR Systems	Boston	Massachusetts	USA
Twomey	Michael	Presenter - Exhibitor	ATMOS International, Inc.	Anaheim	California	USA
Vogt	Daniel	Presenter - Exhibitor	KROHNE Oil & Gas	ZG Breda	The Netherlands	The Netherlands
Weedin	Keith	Presenter - Exhibitor	PCE Pacific, Inc.	Anchorage	Alaska	USA
Zhang	Rocky	Presenter - Exhibitor	Siemens Industry, Inc.	Hauppauge	New York	USA
Figueredo	Julio	Exhibitor	KROHNE Oil & Gas	Calgary	Alberta	Canada
Geiger	Gerhard	Exhibitor	KROHNE Oil & Gas	ZG Breda	The Netherlands	The Netherlands
Incontri	Joseoh	Exhibitor	KROHNE Oil & Gas	Peabody	Massachusetts	USA
Lanoux	Paula	Exhibitor	KROHNE Oil & Gas	ZG Breda	The Netherlands	The Netherlands
LeBrun	Greg	Exhibitor	KROHNE Oil & Gas	Woodinville	Washington	USA
Tetzner	Ralf	Exhibitor	KROHNE Oil & Gas	ZG Breda	The Netherlands	The Netherlands
Olson	Mel	Exhibitor	PCE Pacific, Inc.	Bothell	Washington	USA
Pickburn	Alastair	Exhibitor	Schlumberger	Romsey	Hampshire	UK
Benbedda	Zakaria	Exhibitor	Siemens Industry, Inc.	Hauppauge	New York	USA

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Last Name	First Name	Function	Participating Company or Organization	City	State Province	Country
Burdick	John	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Burleigh	Roger	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Cook	Gary	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Edmunds	Shekinah	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Evans	Gary	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Ha	Young	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Harry	John	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Harwood	Dennis	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Larson	Tiffany	Audience	Alaska Department of Environmental Conservation	Fairbanks	Alaska	USA
Law	Timothy	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
McDermott	Karen	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Nodurft	Beth	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Sanfacon	Keith	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Schorr	Betty	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Spiegel	Becky	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Steele	William	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Swartz	Jeanne	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Wood	Graham	Audience	Alaska Department of Environmental Conservation	Anchorage	Alaska	USA
Silfven	Laurie	Audience	Alaska Department of Environmental Conservation - Industry Preparedness Program	Anchorage	Alaska	USA
Sherwood	Michele	Audience	Alaska Department of Environmental Conservation/Spill Prevention and Response/Prevention and Emergency Response Program	Anchorage	Alaska	USA
Hagedorn	Ben	Audience	Alaska Department of Natural Resources	Anchorage	Alaska	USA
Selvik	Justin	Audience	Alaska Department of Natural Resources	Anchorage	Alaska	USA
Browne	Susan	Audience	Alaska Department of Natural Resources Division of Oil and Gas	Anchorage	Alaska	USA
Iversen	Allison	Audience	Alaska Department of Natural Resources Petroleum Systems Integrity	Anchorage	Alaska	USA
Steele	Marie	Audience	Alaska Department of Natural Resources Petroleum Systems Integrity	Anchorage	Alaska	USA
Brown	Tammas	Audience	Alaska Department of Natural Resources State Pipeline Coordinators Office	Anchorage	Alaska	USA
Haese	Bill	Audience	Alaska Department of Natural Resources State Pipeline Coordinators Office	Anchorage	Alaska	USA
Pierce	Sandra	Audience	Alaska Department of Natural Resources State Pipeline Coordinators Office	Anchorage	Alaska	USA
Taft	Don	Audience	Alaska Instrument	Anchorage	Alaska	USA
Barnett	Steve	Audience	Alaska Instrument/PermAlert	Anchorage	Alaska	USA
Baker	Michael	Audience	Aleut Enterprise, LLC	Anchorage	Alaska	USA
West	Tom	Audience	Asel-Tech USA LLC	Pasadena	Texas	USA
Kaiser	Joe	Audience	ASRC Energy Services	Anchorage	Alaska	USA
Bronson	Mike	Audience	BP Exploration Alaska	Anchorage	Alaska	USA
Bruchie	James	Audience	BP Exploration Alaska	Anchorage	Alaska	USA

TABLE 3 - PIPELINE LEAK DETECTION CONFERENCE PARTICIPANTS

Last Name	First Name	Function	Participating Company or Organization	City	State Province	Country
Chubb	Tyler	Audience	BP Exploration Alaska	Prudhoe Bay	Alaska	USA
Coster	Scott	Audience	BP Exploration Alaska	Anchorage	Alaska	USA
Daggett	Matt	Audience	BP Exploration Alaska	Anchorage	Alaska	USA
Fledderman	Kurt	Audience	BP Exploration Alaska	Anchorage	Alaska	USA
Tu	Jen	Audience	BP Exploration Alaska	Anchorage	Alaska	USA
Finger	Thomas	Audience	Bureau of Land Management / Office of Pipeline Monitoring	Anchorage	Alaska	USA
Heath	Nolan	Audience	Bureau of Land Management / Office of Pipeline Monitoring	Anchorage	Alaska	USA
Wall	Rance	Audience	Bureau of Ocean Energy Management, Regulation and Enforcement	Anchorage	Alaska	USA
Greenstein	Larry	Audience	Chevron	Anchorage	Alaska	USA
Thorsell	Scott	Audience	Chevron	Anchorage	Alaska	USA
Baldridge	Jeff	Audience	Coffman Engineers	Anchorage	Alaska	USA
LaPella	Pete	Audience	Coffman Engineers	Anchorage	Alaska	USA
Liverance	Tom	Audience	Coffman Engineers	Anchorage	Alaska	USA
Schoen	Lee	Audience	Coffman Engineers	Anchorage	Alaska	USA
York	Bonnie	Audience	Coffman Engineers	Anchorage	Alaska	USA
Hasar	John Cankutan	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Jerling	Mark	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Michaelson	Cindy	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Murali	Jagannathan	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Nelson	Mark	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Shifflett	Jeannette	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Singh	Probjot	Audience	ConocoPhillips Alaska, Inc	Anchorage	Alaska	USA
Kirby	Dennis	Audience	ConocoPhillips Alaska, Inc.	Anchorage	Alaska	USA
Catalano	Steve	Audience	Cook Inlet Regional Citizens Advisory Council	Kenai	Alaska	USA
Moore	Ted	Audience	Cook Inlet Regional Citizens Advisory Council	Kenai	Alaska	USA
Munger	Michael	Audience	Cook Inlet Regional Citizens Advisory Council	Kenai	Alaska	USA
Miller	Greg	Audience	Crowley	Anchorage	Alaska	USA
Dummann	Ernest	Audience	du Alaska Incorporated	Anchorage	Alaska	USA
Lewis	Chris	Audience	Enbridge Pipelines	Edmonton	Alberta	Canada
Chapman	Thomas	Audience	Energia Cura	Fairbanks	Alaska	USA
Kelley	Michael	Audience	Energia Cura	Fairbanks	Alaska	USA
Buchert	Jakob	Audience	Energy Solutions International	Calgary	Alberta	Canada
Anderson	Tracey	Audience	ExxonMobil Development Company	Anchorage	Alaska	USA
Denman	Erika	Audience	ExxonMobil Development Company	Anchorage	Alaska	USA
Guimond	Chris	Audience	ExxonMobil Development Company	Anchorage	Alaska	USA
Turner	Mery	Audience	ExxonMobil Development Company	Anchorage	Alaska	USA
Bottorff	Jeff	Audience	Kakivik Asset Management, LLC	Anchorage	Alaska	USA
Geuss	Mark	Audience	Kakivik Asset Management, LLC	Anchorage	Alaska	USA
Sanders	Allen	Audience	Kakivik Asset Management, LLC	Anchorage	Alaska	USA
Schoffmann	Ben	Audience	Kakivik Asset Management, LLC	Anchorage	Alaska	USA
Shepard	Ray	Audience	Kakivik Asset Management, LLC	Anchorage	Alaska	USA

TABLE 3 - PIPELINE LEAK DETECTION CONFERENCE PARTICIPANTS

Last Name	First Name	Function	Participating Company or Organization	City	State Province	Country
Witte	Paul	Audience	Marathon Pipe Line	Kenai	Alaska	USA
Robertson	Tim	Audience	Nuka Research and Planning Group, LLC	Seldovia	Alaska	USA
Dietz	Julie	Audience	OES, Inc.	Anchorage	Alaska	USA
Burnison	Roger	Audience	OMNI Flow Computers, Inc.	Sugar Land	Texas	USA
Cutting	Dan	Audience	Pioneer Natural Resources	Anchorage	Alaska	USA
Miner	Lydia	Audience	SLR International Corp	Anchorage	Alaska	USA
Epstein	Lois	Audience	The Wilderness Society	Anchorage	Alaska	USA
Crosby	Clara	Audience	UIC UMIAQ	Anchorage	Alaska	USA
White	Alex	Audience	Umiaq	Anchorage	Alaska	USA
Humann	Brian	Audience	Unknown			
Steiner	Rick	Audience	Unknown	Anchorage	Alaska	USA
Rockwell	Ted	Audience	US Environmental Protection Agency	Anchorage	Alaska	USA
Whittier	Robert	Audience	US Environmental Protection Agency	Anchorage	Alaska	USA

TABLE 4 - POTENTIAL DEPLOYMENT OPPORTUNITIES FOR PIPELINE LEAK DETECTION TOOLS

Technology Provider Name	Technology Name	Technology Type	Multi-Phase Flow Lines	Crude Oil Transmission Pipelines	Facility Oil Pipelines	Subsea Pipelines	Existing Underground Pipelines	New Underground Pipelines	Above Ground Pipelines	Double Wall Pipe Interstice
AREVA NP GmbH	LEOS®	Vapor Detection and Liquid Sensing Externally-Based System	primary tool[1], possibly limited by length	secondary tool[2], possibly limited by length	secondary tool	secondary tool, possibly limited by length	not applicable	secondary tool, possibly limited by length	secondary tool, possibly limited by length	primary tool, possibly limited by length
ATMOS International, Inc.	ATMOS Pipe and ATMOS Wave	Real Time Statistical Analysis Internally-Based System	secondary tool, limited by accurate flow metering	primary tool	primary tool	primary tool	primary tool	primary tool	primary tool	not applicable
FLIR	GF-300 Series Cameras	Vapor Detection Externally-Based System	tertiary tool[3] for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	not applicable
FLIR	P-600 Camera	Thermal Anomaly Detection Externally-Based System	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	tertiary tool for surveillance	not applicable
hansaconsult Ingenieurgesellschaft	TCS "Tightness Control System"	Static Pressure Test Internally-Based System	tertiary tool[4] to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	not applicable
Krohne Oil & Gas	PipePatrol Leak Detection and Localization System (formerly known as [fka] Gallileo)	Real Time Transient Model Internally-Based System	secondary tool, limited by accurate flow metering	primary tool	primary tool	primary tool	primary tool	primary tool	primary tool	not applicable
Micro Motion, Division of Emerson Process Management	Micro Motion Coriolis Flow and Density Meters	Flow and Density Meters	not applicable	support tool	support tool	not applicable	not applicable	support tool	support tool	not applicable
Omnisens SA	Ditest STA-R Analyzer	Distributed Temperature Sensing Externally-Based System	primary tool	secondary tool, possibly limited by length	secondary tool	secondary tool	not applicable	secondary tool	secondary tool	not applicable
PCE Pacific Inc. / Emerson Process Management	Smart Wireless and WirelessHart Products	Wireless Transmitters	support tool	support tool	support tool	support tool	support tool	support tool	support tool	not applicable

TABLE 4 - POTENTIAL DEPLOYMENT OPPORTUNITIES FOR PIPELINE LEAK DETECTION TOOLS

Technology Provider Name	Technology Name	Technology Type	Multi-Phase Flow Lines	Crude Oil Transmission Pipelines	Facility Oil Pipelines	Subsea Pipelines	Existing Underground Pipelines	New Underground Pipelines	Above Ground Pipelines	Double Wall Pipe Interstice
PermAlert ESP, a Division of Perma-Pipe, Inc.	PAL-AT	Liquid Sensing Externally-Based System	primary tool	secondary tool, possibly limited by length	secondary tool	secondary tool	not applicable	secondary tool	secondary tool	primary tool
Schlumberger Oilfield Services	Integriti Pipeline Monitoring System	Distributed Temperature, Strain and Vibration Sensing Externally-Based System	primary tool	secondary tool, possibly limited by length	secondary tool	secondary tool	not applicable	secondary tool	secondary tool	not applicable
Siemens	Sitrans FUH1010 Ultrasonic Meters	Clamp-on Ultrasonic Flowmeter Internally-Based System	not applicable	support tool	support tool	not applicable	not applicable	not applicable	support tool	not applicable
Telvent USA Corporation	SimSuite Pipeline	Real Time Transient Model Internally-Based System	secondary tool, limited by accurate flow metering	primary tool	primary tool	primary tool	primary tool	primary tool	primary tool	not applicable
Tyco Thermal Controls	TraceTek 5000 Hydrocarbon Sensor Cable and TT-FFS Fast Acting Fuel Probes	Liquid Sensing Externally-Based System	primary tool	secondary tool, possibly limited by length	secondary tool	secondary tool	not applicable	secondary tool	secondary tool	primary tool
Vista Leak Detection, Inc.	LT-100 and HT-100	Static Pressure and Volume Test Internally-Based System	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	tertiary tool to verify pipe integrity	not applicable

Notes:

1   Pipeline operators should first consider primary tools for deployment to monitor for leaks prior to considering secondary or tertiary tools.

2   Pipeline operators should consider secondary tools for deployment to monitor for leaks after considering primary tools but before tertiary tools.

3   Pipeline operators should consider surveillance procedures as tertiary tools for deployment to monitor for leaks after considering primary and secondary tools.

4   Pipeline operators should consider pipeline integrity tests as tertiary tools for deployment upon suspicion of a leak.

APPENDIX A

UTSI INTERNATIONAL CORPORATION *ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION 2011 LEAK DETECTION CONFERENCE TECHNOLOGY ANALYSIS* **REPORT**

Shannon & Wilson, Inc.

Alaska Department of Environmental Conservation 2011 Leak Detection Conference Technology Analysis

Final

UTSI International Corporation
1560 West Bay Area Blvd., 2nd Floor – Suite 300
Friendswood, Texas 77546 U.S.A.

November 30, 2011

TABLE OF CONTENTS

1.0   INTRODUCTION

This report assesses leak detection technology currently available as commercial products with respect to applicability in gas, crude oil, refined product, and multi-phase pipelines including, but not limited to, facility oil piping. The State of Alaska requires the deployment of Best Available Technology (BAT) on crude oil transmission pipelines within Alaska. The term "Best Available Technology" cannot be applied to any commercial product without considering the pipeline for which it is a candidate.   When considering meter-based systems referred to as Computational Pipeline Monitoring (CPM)[1], more than one (1) class of CPM technology would provide good performance on a steady-state pipeline where measurement accuracy is high. Some such systems would not perform well under transient conditions. Therefore, it follows that, for any designation of Best Available Technology, BAT must be defined in a manner that considers specific pipeline hydraulics. The term "BAT" should be considered a reflection of the applicability of a solution under consideration on the pipeline for which it is being evaluated. A determination that a leak detection solution warrants a designation of BAT for a project indicates the following:

- The leak detection solution is not a compromise with respect to cost or convenience at the expense of significant degradation of leak detection performance on the pipeline for which it is considered,

- The solution is applicable for the hydraulic conditions, known or expected to be encountered,

- The system is not prone to generate false alarms when implemented on pipelines similar to the one for which it is considered,

- Instrumentation in place or planned for the pipeline is adequate to support the leak detection system under consideration, and

- When leak detection products are employed as a primary solution or jointly with a secondary solution, the system shall detect a leak in sufficient time to limit the total spilled volume of liquid to no more than one percent (1%) of nominal daily throughput, with "nominal" being the traditional flow rate approaching the rated limits of the pipeline or the maximum flow allowed by external capacity (connecting pipelines, other flow or pressure restrictions, usual fluid availability, etc.), whichever is less.

The requirement that any system must be capable of identifying the presence of a leak and limit the lost fluid to one percent (1%) of daily flow should not be taken to mean achievement of that metric is sufficient to receive BAT recognition. Detection of such a leak on some pipeline segments by some meter-based systems would be trivial with appropriate instrumentation and quite an accomplishment or impossible on other pipeline segments. BAT recognition must be granted on the basis of matching pipeline characteristics with a technology that limits released fluid to the greatest degree possible and no more than one percent (1%) of daily flow on any segment on the pipeline.

The assessment of technologies described herein is general in nature and does not intend to distinguish products based on similar technology. Nor does it intend to make claims regarding product performance that would be influenced by instrument quality and/or applicability of a specific product to the hydraulic

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[1] API Recommended Practice 1130, Computational Pipeline Monitoring for Liquids, Third Edition - September 2007

behavior of the pipeline for which it is considered. Instead, this report intends to describe the strengths and applicability of various technologies in a manner that facilitates proper selection of commercial products for a pipeline based on recognition of benefits offered by their underlying technologies.

An important consideration, often overlooked, is that the pipeline company management must be committed to leak detection and personnel must be adequately trained and given the time to manage the leak detection system. This is especially important in understanding the causes of false alarms and limiting their occurrence.

2.0   EVOLUTION OF LEAK DETECTION METHODS

Early methods of leak detection on pipelines involved simple pressure and flow measurements with evaluation performed by manual means. Familiarity with normal pipeline hydraulic behavior was critical in recognizing anomalies indicative of a leak. Direct observation such as flying or driving the right-of-way (ROW) looking for unhealthy vegetation or released fluid was, and still is, a major method of verifying pipeline integrity.

The evolution of transducers evolved quickly, first to support manual readings, and then integrated with communication systems to transmit results to data collection devices. Over time, new technologies were developed to sense escaping fluid by indirect means such as a disturbance in normal hydraulic conditions within the pipeline, or by external means to detect fugitive fluid in the environment. Indirect detection of leaks using traditional Supervisory Control and Data Acquisition (SCADA) data has evolved from simple comparison of meter readings to sophisticated algorithms to deal with fluid density changes along the flow path and their effect on the apparent pipeline inventory. Other technologies were developed to detect acoustic signatures of escaping fluid in the form of a rarefaction wave at the onset of a leak or vibrations continuously emitted at the leak site. Relatively new products involved the deployment of fiber optic technology to observe thermal characteristics of the environment in search of evidence of a temperature anomaly indicative of a leak. Other tools employ sensors capable of remotely observing fugitive fluid or vapors near the leak site.

2.1   Leak Detection System Performance

From the former API 1155 (Evaluation Methodology for Software Based Leak Detection Systems), there are four (4) results by which modern leak detection performance is graded. These are as follows:

1. The system correctly indicates there is no leak,
2. The system correctly indicates that there is a leak,
3. The system incorrectly indicates that there is a leak (false alarm), and
4. The system incorrectly indicates that there is no leak (failure to detect).

Significant efforts can be expended to achieve only the first two (2) conditions. Four (4) metrics exist to describe a particular leak detection system's performance. These parameters are heavily influenced by the leak detection product's inherent strengths and weaknesses, as well as the pipeline's instrumentation complement and fluid properties. These metrics are as follows:

1. Sensitivity – combination of the size of a detectible leak and the time required to detect it,
2. Reliability – a measure of the system's ability to accurately assess whether a leak exists or not,
3. Accuracy – the ability of a system to estimate leak parameters such as leak flow rate, total volume lost, and leak location, and

4. Robustness – the ability of a system to continue to function in unusual hydraulic conditions or when data is compromised.

These measures of performance are not measures of a leak detection system's inherent quality alone. They are measures of the system's performance as applicable to the pipeline's hydraulic behavior and as implemented with appropriate instrumentation. Pipelines that tend to have variations in linepack, due to thermal influences and varying flow rates, will benefit greatly from algorithms that understand such variations or by leak detection tools whose performance are not influenced by such behavior. Leak detection systems whose performance would be thwarted by thermal transients could only be suitable on pipelines where such transients do not exist.

2.2   Revolutionary Technology

There is always an interest in finding revolutionary technology that provides a major step in leak detection performance or a substantial decrease in cost or complexity of the leak detection system. To be considered "revolutionary," a product needs to be based on a new technology or provide substantially better performance than its earlier versions. However, many revolutionary tools are adversely affected by developmental or deployment issues during their infancy. Consequently, acquiring revolutionary technology can be less attractive than implementing mature and proven technology. A practical alternative to revolutionary technology would be evolutionary technology where implementation issues have been solved and successful deployment is assured. Such products would offer substantially similar benefits as their predecessors, but with incremental improvements in performance or ease of use.

Early Real-Time Transient Model (RTTM) technology was revolutionary with regard to potential performance gains compared to existing meter-based technology. However, unsatisfied goals and unkept vendor promises during the technology's infancy, most of which were caused by inadequate project execution by only a few providers, led to a poor reputation that is still with us today in spite of numerous successful RTTM deployments by pipeline companies whose operations included highly transient hydraulic behavior that would thwart lesser tools. RTTM technology is now considered "evolutionary" because of new deployment and configuration tools, self-tuning algorithms, and instrument quality assessment features. These tools decrease the complexity of RTTM systems while providing optimum performance with less configuration effort.

Fiber optic technology has recently graduated from revolutionary status, where concepts were proven and deployment techniques were still questionable, to an evolutionary status where deployment issues have been addressed to a large degree. Tools have become commercialized and their range of coverage has been increased to a point where equipment deployed at stations along the line may now provide full pipeline coverage. Alarm management protocols have been developed, as have their SCADA integration techniques. Deployment of technologies involving external sensing requires an engineering effort to ensure a leak will provide evidence of its existence to the sensor. This requirement will not change, though a collection of applicable conventions will likely evolve such that proven methods can be selected based on pipeline and environmental characteristics.

Good project management practices require consideration of technology maturity in the kind of application for which it is considered. For example, a particular technology may have a proven track record on land, but none in subsea environments. Careful engineering may mitigate potential risks to a degree the unforeseen problems are unlikely. Even widely deployed commercial products should be carefully considered before deployment on any particular pipeline in order to protect the investment by ensuring success.

2.3   Leak Detection Tools

The purpose of leak detection systems has evolved along with advancements in technology and improved capability. Early meter-based systems, such as simple over/short tabulation, were expected to give the pipeline controller insight into the pipeline's recent hydraulic behavior to enable the controller to form a subjective opinion regarding pipeline integrity. Early over/short analyses were paper-based reports with data taken hourly and manually tabulated as the work load permitted. Later versions were integrated into the SCADA systems, tabulated over multiple time periods, and made available continuously online. Over/short reports, often called the "Hydraulic Summary," are often a favorite SCADA screen with controllers.

As tools became more sophisticated and trustworthy, many companies chose to eliminate the controller's subjective evaluation from the process and rely solely on a leak detection system's algorithms. However, the limitations associated with early algorithms combined with compromises in instrumentation availability and/or quality often led to false alarms. The natural solution is increasing alarm thresholds and/or persistence criteria so transient conditions that momentarily share hydraulic characteristics with those of a leak do not trigger an alarm. Where the controller has good familiarity with pipeline operation, there is no substitute for alarm settings that draw the attention of the controller to hydraulic anomalies in order to apply operational experience in determining pipeline integrity. This allows more sensitive operation with potentially shorter detection times, especially when leak detection systems employ sophisticated linepack analysis techniques before issuing an alarm.

In many cases the leak analysis protocol evolved from using the controller's familiarity with the pipeline behavior in a subjective analysis to an automated process at the expense in detection time or sensitivity. Over time, some companies returned to programs of operating near sensitivity limits in order to regain the performance lost when an automated leak analysis is configured to prevent false alarms in all cases. This philosophy requires that the Pipeline Leak Detection (PLD) tool employed only issue false alarms with predictable causes in order that the controller recognizes the cause of the alarm and the persistence it should exhibit. Thus, subjective evaluation returns with the benefit of the leak detection system drawing attention to the anomaly. In many cases more sophisticated tools are used to limit false alarms, or secondary tools are used to extend sensitivity and/or shorten detection time; therefore, allowing the primary tool to be configured to eliminate its false alarms with no overall performance penalty.

2.4   Best Available Technology

Most proven commercially available leak detection products could be considered Best Available Technology (BAT) compliant for some pipelines. Many could not be considered BAT compliant on all pipelines operated in Alaska. For example, systems whose performance would be thwarted by end-to-end fluid temperature extremes would be inappropriate where such extremes may exist. However, the system may be BAT compliant where such extremes do not exist.

It is also possible for a limited capability solution to be considered compliant with BAT requirements if it extends the sensitivity range or shortens detection times when used in conjunction with another solution. Such a system may, or may not, be considered BAT compliant if operated alone.

Systems may be considered BAT compliant for a primary leak detection system if other methods offer no performance advantages due to pipeline characteristics and operating conditions including, but not limited to, transient operation, multi-phase flow, etc. In the case where another solution offers significantly better

performance under target conditions, the lesser tool, though it might meet minimum performance standards, would <u>not</u> be considered BAT compliant.

Pipeline operators should engineer a BAT compliant project with the goal of detecting probable leaks as soon as possible after the leak event. This engineering effort may affect pipeline deployment methods and Right-of-Way (ROW) management. Such engineering should be done with the support of potential vendors of leak detection products, especially those that are deployed along the ROW or in the trench with the pipeline. In the case of meter-based solutions, the engineering effort would be more oriented toward selecting a leak detection solution that is capable of required performance under expected operating conditions. It is incumbent on the pipeline operator to investigate vendor performance claims with respect to applicable criteria including, but not limited to, the following:

1. Are the target pipeline, fluids, operations, and other characteristics similar to the conditions for which the vendor's specified performance specification applies?

2. If the system depends on metered flow accuracy, yet the system specifications have no published dependency on flow measurement quality and pipeline characteristics, one should be cautious in assuming published performance specifications apply on the target pipeline.

3. Does adequate instrumentation exist to support the leak detection tool? Are there adequate instruments available at each station and are stations sufficiently distributed to avoid long segments that increase linepack uncertainty?

4. Are there operational characteristics that would thwart development of evidence of a leak? Such a case would be regulated injection pressure coupled with a leak just downstream of the injection point where pressure excursions are a dominant component in leak assessment algorithms. In this case, evidence of a leak would only be seen in a flow imbalance because pressure regulation simply increases flow to maintain pressure.

5. Does the system's algorithms accurately assess the linepack to a degree linepack uncertainty is sufficiently small under all conditions to avoid false alarms at the desired performance level? Vendors offering sophisticated linepack assessment tools generally offer detailed information for marketing benefits. Some vendors are expected to have an over-optimistic view of their assumptions and compromises used in their linepack assessment such that the operators should perform their own independent analysis based on published algorithms, or based on proprietary algorithms after non-disclosure agreements are negotiated. When algorithms are withheld, the operating company should assume significant compromises exist in the algorithms, and any estimate of potential performance can only come from experience on similar lines in a similar environment.

6. Are pipeline operating personnel available with sufficient training and time to make use of the important features of the PLD? PLDs that are capable of addressing transient and thermal behavior of the pipeline generally require a significant personnel commitment early in the implementation and tuning process. Vendor staff can provide expertise for tuning with support from operator staff familiar with pipeline characteristics and operations.

In the case of pipelines under construction or considered as future projects, where modifications or the design of new pipelines can substantially improve leak detection performance, or can enable one or more leak detection technologies to meet performance requirements, such infrastructure support is required for

BAT compliance. In the case of existing pipelines, BAT compliance requires necessary instruments in support of the potentially BAT compliant leak detection tool.

Solutions cannot be considered BAT compliant when installed with inadequate supporting instrumentation. An example of inadequate instrumentation may include, but not be limited to, flow meters operating below their operating range as specified by their manufacturer or at a rate for which inaccuracy thwarts achievement of required leak detection performance. Other examples of inadequate instrumentation include operating conditions outside the specified range or hydraulic conditions for the instrument (environmental temperature below specified operating limits or inadequate flow conditioning) or inefficient configuration or calibration for the expected span requirements of the instrument.

3.0   TESTING

Pipeline Operators are required to demonstrate their ability to meet specified leak detection performance specifications by methods appropriate for the construction of the pipeline. Onshore pipelines should be subject to measured fluid (crude oil) withdrawal into containment vessels. A solution for offshore pipelines and onshore pipelines, where fluid withdrawal is impractical, may involve manipulation of actual instrument data to simulate a flow imbalance or other leak indicators. Where double-wall pipe is deployed and the annulus is monitored for fluid contamination, no testing is required that would result in contamination that would adversely impact future leak detection or increase the rate of corrosion after testing. Instead, an engineering analysis should be performed to identify expected leak detection performance.

Sometimes, tests require special equipment or modifications to the pipeline. An ethylene pipeline in Belgium has flares every ten kilometers which can be used to vent actual leaks. An anhydrous HCl pipeline on the Houston Ship Channel used a tank truck containing a caustic solution to absorb leaked HCl vapor. These are extreme cases, beyond what one would expect for most pipelines. Generally, pipelines in high hazard areas will require more stringent testing.

4.0   METER-BASED TECHNOLOGY

Flow meter-based technology has evolved from simple meter comparisons (instantaneous or accumulated flow over an observation interval) to use more sophisticated algorithms performing linepack analysis in order to properly allocate any observed flow imbalance to a change in pipeline inventory. Meter-based systems eventually became known in the industry as Computational Pipeline Monitoring or CPM. This name originally applied only to methods that employed computational algorithms to replace the need for manual calculations. However, other proven technologies, such as acoustic detection of the rarefaction pressure wave caused by a pipeline rupture, have been added to that definition.

Meter-based CPM is the dominant method employed on long transmission lines. It does not require instruments between major stations, though detection times are adversely affected by linepack uncertainty over long distances between instruments. This method requires meters at all entry and exit points. Achievable sensitivity is determined by the aggregate accuracy of all meters serving as boundaries for a given pipe segment. Alarm thresholds must tolerate expected flow/volume imbalances as the linepack changes during normal operation. Algorithms that can correlate flow imbalance with inventory changes provide better immunity from false alarms and masking of leaks at configured sensitivity levels. Practical sensitivity thresholds also improve with meter accuracy as illustrated in Figure 4.1-1. The figure represents an API 1149[2] typical pipeline with various combinations of meter accuracies serving boundary conditions for the segment being evaluated. It is critical to understand that poorly understood temperature/density profiles, as are likely in the Alaskan environments and with typical operating conditions, would severely hamper any attempt to achieve good leak detection performance using meters of any quality. However, assuming good understanding of the temperature/density profiles and good leak detection algorithms, the following example illustrates the effect of meter quality on leak detection performance.
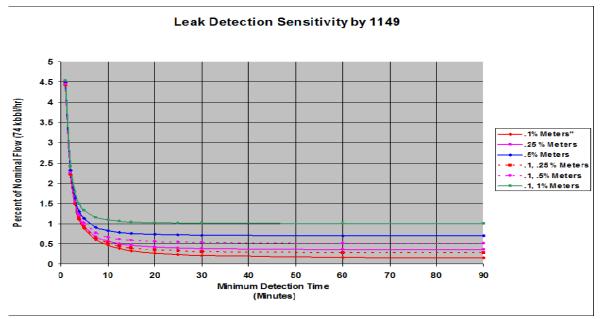
Figure 4.1-1: Influence of Meter Quality on Performance.

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[2] API Publication 1149, Pipeline Variable Uncertainties And Their Effects on Leak Detectability, First Edition, November 1993

The major limitation in meter-based CPM is due to transient changes in linepack during normal pipeline operation. Control actions, such as valve operations, changing injection rates or delivery paths, can cause the line to unpack just as a leak might, or to pack, which can mask a leak. This contributes to a short-term uncertainty regarding the inventory of the line as the line re-stabilizes after the transient dissipates. Such transients need to be either tolerated, or understood by the leak detection system. Systems involving Real-Time Transient Models (RTTM) understand the expected transient behaviors and can perform short-term assessments regarding the influence of the transient on the linepack, thus avoiding any premature assumption that a predictable linepack disturbance may be a leak. Over an extended observation interval, the hydraulic effect of transient behaviors is dwarfed by aggregate fluid throughput, thus allowing good sensitivity without having to consider transient behaviors to such a degree as is necessary over short time periods. In any case, persistence is a leak characteristic not shared by transient behavior.

4.1 Instrument Quality

Instrument quality determines the performance of any leak detection system dependent on the instrumentation monitoring pipeline operating conditions. This is especially true of flow measurements in meter-based algorithms. Instrument placement is critical to avoid erroneous readings due to flow stream inconsistencies or isolation of the instrument under unusual configuration of valves and flow paths. Instrument error can contribute to leak alarms that are false with respect to pipeline integrity, but legitimate with respect to consideration of hydraulic data that may be evidence of a leak. It is not unusual for a controller to recognize instrument error in a particular reading while other readings remain normal; thus rendering an otherwise probable indication of a leak suspicious. This assessment, however, requires training and experience with pipeline operations and should not be made without a high degree of confidence in pipeline integrity lest a real alarm be dismissed as probably false.

4.1.1 Linepack

For the purposes of this report, "linepack" is loosely defined as the quantity of fluid in the line, or missing from the line, compared to the dry volume of the pipeline; dry volume being the cross-sectional area multiplied by the length. Linepack is often referred to as the difference in actual contents and the net contents under standard conditions of temperature and pressure. In most of our discussions, fluid never achieves standard temperature and pressure so our interest is largely focused on changes in inventory relative to its quiescent state under steady-state conditions.

To fully understand the influence of linepack on meter-based leak detection, it is necessary to envision the injection of fluid into the line along with the opposition to that injection in the form of backpressure. Any increase in flow, due to an increase in injection pressure, will result in an immediate change in the pipeline inventory or linepack until the pressure wave travels to the delivery site and delivery flow increases accordingly. Linepack settles to a new semi-quiescent state as injection and delivery flows converge. At that point, any heat lost from the fluid to the environment continues to affect the linepack until a new fully quiescent state is achieved.

To illustrate the effects of temperature on linepack, consider the pipeline filled at elevated temperature, and capped at both ends. Any cooling of the fluid will appear in the line pressure as a partial vacuum as fluid density increases to require less space. Then, envision a line filled with cold fluid and capped before the fluid temperature is elevated. In that case, density is reduced as fluid expands to create an increase in pressure. Under flowing conditions, thermal effects result in linepack variations that effectively pull or push batch interfaces along the line as densities change due to heat migration to the environment. The

effect is that the same inventory of the pipeline can occupy more or less space in the line as heat is transferred, or that the pipeline's capacity can vary as fluid density varies.

Most of the limitations inherent in meter-based leak detection are a direct result of not being able to fully understand variations in linepack as fluid density changes occur along the line. Leak alarm thresholds must be set to accommodate normal packing and unpacking of the line during transient conditions, and must tolerate any uncertainties involved with linepack estimation.

Meter-based leak detection methods of the simple form will not exceed predicted performance according to API-1149 because API-1149 describes the limits of performance based on known uncertainties. However, uncertainties can be reduced by more frequent instrumentation along the line to shorten segment lengths (less volume), as well as improved algorithms for estimating the linepack. Some systems can be sensitive to disturbances in linepack as well as the actual balance of volumes, thus developing early confidence in a leak indication.

In cases where fluid temperature varies very little from injection to delivery sites, the slope of the density profile is substantially flat and linear. Where there is a substantial difference in temperature from end to end, the density profile may vary in shape as fluid of one temperature is injected behind fluid of another temperature. The density profile can take on characteristics indicating a step change in density followed by development of a slowly evolving non-linear density profile over the length of the line. Simple estimates of the density profile may not sufficiently characterize the changing linepack to the extent that the inherent leak analysis algorithms are effective in detecting leaks without undue false alarms. Consequently, any algorithm for estimating the ongoing changes in linepack, short of a real-time transient model, should be evaluated in detail to determine its effect on the accuracy of linepack estimates. Issues that are expected to thwart arbitrary estimation algorithms include the following:

- Varying flow rates,
- Varying pipeline installation characteristics (surface and subsurface),
- Varying environmental temperatures,
- Varying soil moisture content,
- Water crossings, and
- Batched operation.

In the cases above, it is difficult to adapt endpoint measurements to linepack assessment using methods such as averages and weighted averages, where localized influences can significantly affect fluid dynamics and the actual density profile affecting volume balance accuracy.

It is important when selecting a meter-based leak detection system to understand the influence of temperature on potential leak detection performance. When the injection temperature is very close to the delivery temperature (indicating no significant heat transfer is occurring) there is little, if any, need for sophisticated algorithms to track and assess fluid density changes due to the temperature profile along the line. This may occur when the pipeline is short and transit time is sufficiently low that there is no time for fluid temperature to change during transit, or if the fluid injection temperature already matches that of the environment. When the injection temperature is different from the delivery temperature, there will be differences in fluid density at injection and delivery points. In such cases the actual fluid density along the line will vary with temperature that is not measurable between temperature sensors. In this case more advanced algorithms are needed to track fluid temperatures along the line and include density variations in linepack estimation. Such algorithms are capable of decreasing linepack uncertainty and consequently increasing leak detection performance.

4.1.2   Measurement Uncertainty

API 1149 provides an estimate of leak detection performance based on measurement uncertainties and their adverse effect on leak detection performance. There are, however, significant questions regarding what parameters are reasonable for any pipeline configuration. Traditional SCADA measurements are valid for only the location where they are measured, yet the influence of these measured parameters affects fluid throughout the pipeline.

In the case of pressure, its effect on crude oil density is less of an influence than temperature. Generation of pressure profiles considering the influences of elevation, friction and other parameters is rather straightforward using Real-Time Transient Model (RTTM) technology. Even without detailed analysis of the effects of pressure along the line, estimates of the pressure profile can yield reasonable results.

Variations in temperature will have a significant effect on crude oil density. Fluid injection at elevated temperatures with respect to the environment will produce a corresponding delivery of a substantially equivalent, but slightly lesser, volume of higher density fluid. The degree to which incoming and outgoing flows differ is strongly influenced by the temperature difference between injection and delivery sites. During steady-state operations, both the thermal and density profiles along the line are relatively stable, though possibly poorly understood by some leak detection algorithms. During transient operations such as a step change in flow rates, the quiescent state of the thermal profile is disturbed, thus altering heat migration from the oil to the environment. In the case of an increase in flow, the thermal profile is lengthened as fluid travels further down the line while heat is being lost. The thermal profile will become more linear for higher flows. In the case of a decrease in flow, the thermal profile will contract and become more non-linear as more heat is transferred to the environment a shorter distance from the injection point. If the pipeline flow is low enough that the fluid temperature substantially achieves equilibrium with the environment well before discharge, it becomes impossible to use endpoint measurements to estimate the temperature profile along the line. This is due to the inability to estimate the shape of the curve because thermal equilibrium may have occurred anywhere along the line.

Variations in the thermal profile and changes in its shape are significant problems for meter-based leak detection methods because the natural flow imbalance expected with normal operations will appear to be a shortage (more injected than delivered by volume, or a leak) or an overage (masking a leak) when considering net, or mass, flow through the meters. This can be aggravated by the relatively instantaneous influence of pressure causing the change in flow compared to the longer term thermal effects along the line.

Meter-based methods deal with this problem with varying degrees of success. In cases where fluid injection temperature is substantially the same as delivery temperature, simple algorithms can largely ignore the uncertainty in the temperature profile with reasonable success. Where this is not the case, the sophistication of the product's method of estimating the temperature profile will determine the leak detection performance.

When considering commercially available leak detection systems for use on a particular pipeline, one should expect long lines or lines with low flow to have very non-linear temperature profiles. Such profiles are difficult to estimate using simple linepack estimation methods, especially under varying flow conditions. Short lines, or lines in which fluid temperature changes vary little from one end to the other, are suitable for most linepack estimation algorithms. When in doubt, it is prudent to err on the side of caution.

4.2   Flow Balance Techniques

Strictly speaking, flow balance is simply instantaneous comparisons of incoming meters and outgoing meters with the algebraic sum of the flows approaching zero (0) to indicate no leak exists. Exact balance is difficult to achieve in all but steady-state pipelines, and then only under the most ideal conditions. The simplest flow balance algorithms do not deal with linepack and, therefore, must tolerate normal linepack excursions by reducing sensitivity or averaging flow imbalances over long time intervals which increases the response time. Step changes in flow, such as one caused by bringing a pump online, do not appear downstream until the pressure wave travels to the downstream meter; after which the downstream meter measurement moves toward the upstream flow level as the line packs to develop the new pressure profile. The term "flow balance" is also used to reflect simple tabulations of accumulated flow over various time intervals. This technique is more often referred to as "volume balance," though the term "volume balance" can reflect additional complexity besides integrated flow only.

Flow balance techniques in the form of raw volume balance are most appropriate on <u>short, high throughput</u> pipelines where fluid contents are relatively incompressible liquids, and where fluid sources may be switched among a hot fluid source (low density) and a cold fluid source (high density). Given the incompressible nature of the fluid and limited opportunity for fluid temperature/density to change in transit through the short line, simple barrel in/barrel out flow balance can provide acceptable correlation between incoming and outgoing flows. Measuring high density fluid (cold) coming in and low density fluid (warm) going out can erroneously indicate a loss of fluid on a net-barrel to net-barrel basis in the absence of adequate line pack corrections. This would also suggest that volumetric meters, which do not automatically provide net corrected volumes, can be used effectively in some circumstances. In this example, should a cold fluid be injected behind a hot fluid, the net delivered product would appear to be less than the injected product until the warm fluid is flushed from the line and the discharge fluid density becomes consistent with the injected fluid density. Since simple flow balance algorithms do not address changes in linepack, any apparent net flow discrepancy can appear to be a leak, or can to mask a leak.

4.3   Volume Balance Techniques

Volume balance techniques cover flow accumulations over various time intervals. The simplest of these algorithms, and the one most associated with the name, does not provide pressure and temperature (P/T) compensation in the volume balance algorithms. Instead, over/short tabulations for several time intervals are presented to the controller so that the controller can subjectively determine if the observed packing or unpacking rate is normal for the operating conditions. Originally done with manual tabulations, the over/short tabulation is usually automated and incorporated in commercial meter-based systems as a familiar diagnostic tool used by controllers to confirm that hydraulic behavior is normal over convenient time intervals.

The short pipeline example described above is an example of where simple volume balance techniques provide reasonable leak detection performance. Using volume balance techniques, any persistent growing fluid shortage would be indicative of a leak.

While volume balance does not necessarily include P/T compensation, it can still apply to net measurement where flow computers or meters provide net flow measurements to the system. Where fluid densities are normalized prior to the balancing algorithm, this version of volume balance is often called mass balance.

It should be noted that many leak detection system vendors, including suppliers of RTTM systems, who track accumulated flow describe their systems as "volume balance" methods regardless of the level of

sophistication of their linepack compensation algorithms. This is a reasonable sharing of the term because standardized volumes of the same product are actually measurements of the mass.

4.3.1   Mass Balance

Mass balance is the unambiguous name for balancing the quantity of fluid volumes corrected for density changes (usually corrected to net standards of 60 °F with appropriate compensation for pressure) passing through the pipeline segment bound by meters. Using net volumes in balance algorithms provides an accurate measure of the quantity of fluid entering and exiting the pipeline over any observation interval.

This technique may estimate a temperature/density profile to improve results of the assessment, by taking the change in linepack into account. The degree of effectiveness of this compensation is determined by many influences, including pipe segment length (volume and opportunity for heat migration) between instrument locations, flow rate stability, fluid injection temperature, soil thermal characteristics, control actions, etc. Most algorithms, except where assisted by a real-time transient model, do not deal with all significant influences on the fluid density profile accurately between stations along the pipeline.

Where pressure/temperature corrections are applied to balance volumes more accurately based on an estimated density profile, assumptions must be made regarding the evolution of the density from the fluid injection point to the delivery point. These assumptions may include any of the following algorithms:

- Linear average of injection density and delivery density,
- Weighted average of injection density and delivery density, or
- A custom curve-fit density profile based on empirical or experimental data.

Mass balance systems are generally very applicable under conditions for which their linepack approximation algorithms apply. Their ability to understand changes in pipeline inventory takes into account approximated fluid density profiles. However, if the fluid temperature is elevated compared to environmental temperature, varying flow rates will result in varying heat transfer rates along the line, as well as varying fluid density along the line. For a situation where a quiescent steady-state operation exists and the flow rate is raised significantly, fluid will retain heat over a longer distance during transit, thus making most approximation algorithms less accurate. Any apparent shortage may cause a false alarm, while an overage masks a leak by making it necessary to have a larger actual leak to exceed the leak alarm threshold.

On short pipeline applications where fluid is single phase and fluid temperature profiles are somewhat linear, any of several linepack approximation methods are applicable. Where fluid temperature approaches ambient temperature while in transit, the temperature profile will be more logarithmic such that a weighted average or custom curve fit are better suited for estimating changes in pipeline inventory.

Some systems may be characterized as "mass balance" by their vendors due to the fact that they use net flow data from flow computers or meters that correct for temperature and pressure at the flow measurement points. Such a declaration of their method being based on mass balance technology may be grossly exaggerated since changes in linepack are not considered. The result is some combination of less sensitivity, longer response times, and more false alarms.

As described above, there are several conventions by which mass balance systems can estimate contributions of flow imbalance on linepack. Care should be taken in accepting claims of "mass balance" as the basis of a product's technology only until a review of the product's method of assessing linepack changes indicates an appropriate method of assessing linepack is inherent in the product.

Where variations in the temperature profile along the line exist due to varying flow rates, universally assumed density profiles may become so inaccurate under transient conditions as to result in poor leak detection performance. Under such conditions a real-time transient model can properly track the varying temperature/density profile along the line.

4.3.2   Batched Pipelines

Batched pipelines present a special problem because the pipeline is always in a transient mode when a batch interface is in the pipeline. Different viscosities cause a continually changing pressure drop/flow relation. Different product densities at the ends produce different mass flows even though both ends may have the same volumetric flow. A real-time transient model or other algorithms tracking the batch interface can take the effect of the moving batches and different products at the ends into account, but simple balancing algorithms generally don't work well on all batched pipelines.

4.3.3   Real-Time Transient Model

Mass balance assisted by a Real-Time Transient Model (RTTM) is the most sophisticated meter-based leak detection method available. Software license fees are commensurate with the additional benefits offered by RTTM technology when compared to other meter-based tools. These benefits include fewer false alarms and quicker development of confidence in the validity of a probable leak condition through the RTTM's better understanding of linepack characteristics. This can result in less spillage before a leak is detected.

A RTTM is able to account for usual transient conditions in its linepack assessment. The thermal model component tracks fluid temperature based on modeled heat transfer characteristics and accounts for the fluid density profile along the pipeline. Most such systems can model the behavior of light "spongy" hydrocarbons or even gases and, therefore, can provide good leak detection on pipelines whose fluid types and/or operating strategies thwart other meter-based methods.

RTTM solutions have a reputation for requiring ongoing maintenance. This belief is not entirely correct. During the 1970s and early 1980s, there were numerous instances where model performance not only failed to meet expectations but, in some cases, was problematic, thus requiring significant attention to achieve performance goals. The technology has matured significantly since then and RTTM suppliers who have survived offer much more stable products that require less customization in code in favor of configuration of pipeline and fluid property tables. Several pipeline operators responsible for numerous pipelines have standardized on RTTM technology. In another case, a company who required high performance leak detection due to a high consequence environment deployed this technology because their single pipeline is very transient in nature, including wide excursions in fluid properties including batch temperatures.

Once a model is deployed and tuned to provide acceptable performance, contrary to the prevalent RTTM reputation, there is little need for further attention. However, RTTM tools ALLOW continued refinement of modeled parameters in search of still better performance. This effort is not uncommon where RTTMs are in place. Modern RTTM tools also provide significant self-tuning capabilities and/or tuning assistance. Any major change in pipeline characteristics will require an update in the model configuration, as would be the case for other systems.

While RTTM solutions offer the most accurate assessment of linepack changes and, therefore, potentially the shortest leak detection times with confidence, their overall sensitivity is limited by meter accuracy, as

are all meter-based methods. The advantage provided by the RTTM system is rapid recognition of discrepancies in the linepack and the current flow/volume balance. Most RTTM systems provide for the user to make tradeoffs between sensitivity, response time, and false alarm probabilities.

RTTM tuning methods can vary among implementations, though refined tuning is often automatic after basic system configuration. For the most part, tuning includes heat migration parameters and density profiles which can affect growth or shrinkage of a batch in batched environments. Modeling this phenomenon is the most accurate method of accounting for temperature effects related to changes in linepack and flow/volume balance. Implementation methods include tuning heat transfer characteristics (primarily ground thermal conductivity and ambient temperature) in order to align modeled interface arrival to coincide with observed arrival in batched operations. Another approach is placement of a temperature transmitter a few miles downstream of the injection point in order to determine heat transfer parameters using temperature information acquired empirically. To attain the best performance available from a RTTM, it is useful to implement some method of checking modeled thermal behaviors with actual temperature measurements prior to achievement of thermal equilibrium with the environment.

Commercially available RTTM systems typically do not offer leak detection in multi-phase applications without special algorithms to deal with varying relationships between phases and variations in flow patterns in the pipe. Varying flow rates can allow collection of varying amounts of liquids (slugs) in low points in the pipeline. Flow increases can trigger slug expulsion, which is usually observed as a restriction in gas flow due to blockage of the line by liquid contents. Slug formation is unpredictable by a single-phase RTTM and has a significant influence on hydraulic behavior. Where this is a problem, special algorithms are needed to tolerate the up and downstream pressure/flow disturbances during slug formation and expulsion.

4.3.4   Multi-Phase Flow Models

There are a few products specifically designed for multi-phase flow. The few that offer leak detection are a super-set of more familiar single-phase RTTM tools. Their main operational benefit is in predicting slug formation in order to allow changes in pipeline operation to limit slug formation. Prediction of slug formation may include the use of various parameters such as water content in the flow stream, as well as empirical data such as the typical frequency of slug formation under particular hydraulic conditions. As flow is decreased and more heat is lost in transit, there will be an increase in condensate formation. As flow is increased, condensate already collected in pools may be propelled down the line and collectively form slugs of liquid that will cause upstream pressure to rise, downstream pressure to fall, and may damage equipment such as unprotected downstream turbine meters. Leak detection on multi-phase lines must include special algorithms to recognize or predict slug formation and tolerate their hydraulic effects. The accuracy of a multi-phase model may be significantly enhanced by the concurrent deployment of a fiber optic distributed temperature system that can provide the model an accurate temperature profile for the pipeline. Accuracy of multi-phase models is limited by multi-phase flow measurement accuracy and uncertainty in condensate formation and expulsion. Currently available multi-phase flow models tend to be unstable and are unsuitable for unattended operation without highly customized algorithms developed empirically to deal with predictable operational behaviors. Accuracy, sensitivity, and robustness of this solution is not expected to be good, and thus deploying secondary solutions that may be very sensitive to released fluid is recommended.

4.4   Multi-Phase Flow Meters

Multi-phase meters typically do not have nearly as high an accuracy specification as would be seen for single-phase meters. Consequently, phase separation provides a significant improvement in leak

detection performance where separate pipelines are used for each fluid being transported. Even where flow streams are homogenized by increasing its velocity to create a mist of uniform characteristics for improved flow measurement, multi-phase leak detection remains problematic because the flow stream tends to separate after leaving the flow conditioned area around the meter. Uncertainties in fluid behavior and phase change tend to thwart single-phase meter-based solutions on pipelines of sufficient length that significant condensate forms or slugging occurs.

4.5   Statistical Methods

Several products advertise their use of statistics in their algorithms. Statistics alone do not provide a good substitute for understanding the relationship between changing linepack and flow balance. All leak detection algorithms involving the relationship between pressures and flow apply rules and mathematical operations to determine if a leak probably exists. In some cases, these rules involve well-known statistical operations in their algorithms. While some statistical operations are more commonly thought of as estimating the probability of a random event or viewing the distribution of data elements within a set of data, these tools can be applied in a manner that identifies the relationship between data elements collectively among known relationships typical of leak and non-leak conditions. The result is a vision of pipeline integrity based on the output of statistical operations applied to data collected and processed in a manner supporting the chosen algorithms.

Statistical methods apply algorithms to determine the probability a leak exists based on relationships between pressures, temperatures, and flows. These tools can sometimes "learn" normal operational relationships to serve the basis of future leak assessments. They typically support mass balance as a primary basis for pipeline integrity assessment, and then apply their special algorithms to identify evidence of a leak and to prevent false alarms. This method has been applied successfully in very transient environments where "learned" normal behavior does not generate alarms. Statistical methods can offer a simple way to limit false alarms effectively with little configuration effort. Such a system was observed to perform satisfactorily in a highly transient environment after a competing product replaced a 1970s vintage RTTM system, but was unable to provide adequate integrity monitoring due to constant false alarms. The statistical system's advantages are typically a low false alarm rate and a simpler configuration. However, the RTTM solution has a performance edge in some environments with its superior understanding of linepack excursions rather than tolerance of them. The best solutions use statistical methods to refine the results of an RTTM method after the known transient effects are taken into account. Most RTTM systems do this to some degree.

5.0   NON-METER BASED METHODS

Direct observation methods are those that sense the actual released fluid or evidence of fugitive emissions. Such methods include the following:

- Hydrocarbon sensing cable for liquid hydrocarbons, such as gasoline or diesel,
- Vapor detection for liquid or gaseous products,
- Visual observation by traveling the right-of-way at ground level and observing vegetation stress,
- Airborne visual observation, and
- Sheen detection on water using vapor detection or optical analysis.

Details regarding the leak detection technologies introduced in this section   and other common non-meter based products are described in the following subsections.

The hydrocarbon sensing cable is highly sensitive to small amounts of contaminant, typically gasoline or diesel fuel, potentially in the range of teaspoons with the necessary direct contact. Once contaminated, the activated portion of the cable and surrounding soil must be replaced. With the relatively short range possible with this method, it is not considered suitable for long transmission lines. However, it is suitable for short High Consequence Areas (HCA) where it is applicable for the fluid being transported and any released fluid will contaminate the cable.

Vapor detection can take on several forms. One involves drawing air through a perforated tube buried with the pipeline. Any hydrocarbon vapors drifting into the tube will be collected during the sampling interval. Leak location can be determined by the location of the vapor in the flow stream if a marker gas is injected at the end of the tube to mark a complete sample. There is a finite time required to acquire a complete air sample from the right-of-way; thus preventing continuous monitoring of the entire pipeline for potential leaks. Another implementation of this technique involves injection of a trace gas into a line and towing a sensor over the line to detect the trace gas. By using a unique tracer additive in the flow stream, this method can confirm the presence of a leak in a busy right-of-way containing several pipelines to identify the source of the leak As with any external leak detection method, vapor sensing technology for above or below ground piping requires consideration of various options for collecting evidence of a leak

Dead vegetation in southern climes can indicate leaked hydrocarbons in the right-of-way. At least one pilot reported such evidence of a leak, only to learn later in the investigation that a farmer cleared a corner of his field with Roundup weed killer where a brush hog mower would not fit. Observance of pooled fluid on the surface of the ground is a common method of leak detection in Alaska. Pooling of fluid on the surface is expected regardless of the above or below ground location of the leak.

Sheen detection is viable downstream of a water crossing. However, in navigable waters, an oil sheen can be a normal occurrence with winds concentrating the sheen on the downwind bank of the waterway. Provision should be made for deployment considering usual or seasonal wind directions and background sheen levels if they exist.

5.1.1   Acoustic Methods

Acoustic tools come in two (2) types. The first detects the rarefaction pressure wave caused by the sudden onset of a leak. Unlike a meter-based method that can identify a pre-existing leak after the leak

detection system is started, this tool cannot detect a leak if it is not active when the leak occurs because it is sensitive only to the rarefaction wave that occurs at the time of the rupture, It cannot recognize a stable difference in pressures or flows as evidence of a leak but it can determine the location of a leak more accurately than can meter-based systems by measuring the arrival times of the pressure waves at sensors on either side of the leak. Some implementations of this technology may employ a pair of sensors at each end of the covered pipe segment in order to determine the direction from which a pressure wave comes. Pressure waves that arrive at the outer sensors first are ignored because they originate from outside the protected area.   Small, slow growing leaks that do not provide a recognizable pressure wave are not detectible by this method.

A second type of acoustic tool can detect the ongoing audible signature of escaping fluid. Because of limited range, these tools are more suitable for short interplant lines or as companion methods to augment meter-based solutions.

There are pig-like tools available to travel through the line internally to detect the continuous acoustic signature of a leak, thereby providing full length integrity checks where launcher and removal points exist. These are typically used only on a periodic basis and, therefore, are not usually suitable for primary leak detection systems.

5.1.2   Fiber Optic Techniques

Fiber optic technology is being commercially deployed in pipeline integrity monitoring applications with good success. This technology, in the form of Distributed Temperature Sensing (DTS), offers continuous monitoring of the pipeline and provides high accuracy measurement with regard to leak location and high sensitivity where fluid temperature is different from the environment to the degree that leaked fluid will affect the fiber temperature. The key to successful deployment of DTS technology is thermal isolation from fluid still contained in the pipe combined with close thermal proximity of the fiber to released fluid. In the case of crude oil at elevated temperatures, the heat source is the original temperature of the fluid. In the case of most compressible gases, the expansion of the fugitive gas at the location of the leak provides a convenient temperature differential between contained fluid and released fluid that cools upon escape.

Any deployment plan for DTS technology must include consideration of methods to ensure a temperature disturbance of the fiber at the leak site. This can be ensured by insulating the fiber from the pipe in a manner that allows fugitive fluid to overcome the effects of insulation. In the case of natural gas, the fiber can be mounted on the pipe if the cooling effect of escaping gas can predictably cool the pipe circumferentially to a degree that desired sensitivity requirements are met. The fiber can be mounted away from the pipe in a manner that the temperature of percolating gas or oil will affect the fiber, usually in a position above the pipe. In this case, trench fill material provides insulating effects until the fluid escapes the pipe. In the case of new flow lines using double-wall pipe, if the interstitial space between pipe walls is insulated, bonding the fiber to the outer wall provides a level of isolation with enhanced thermal conductivity in the event of an internal leak or an external leak in subsea environments. A leak in the internal pipe will allow warm fluid to migrate to the outside layer of steel and cause destruction of the insulation under pressure, thus creating a thermal event. A leak in the outer wall will result in some increase in pressure in the annulus due to the subsea environments, and will improve heat conductivity between the inner wall and the outer wall; again creating a thermal event.   Since it is commonplace in Alaska to heat crude oil to temperatures higher than ambient temperatures to improve flowing conditions, there is usually a potential source of heat able to supply evidence of a leak provided the installation method isolates the cable thermally from contained crude oil and does not isolate it from the elevated temperature of the leaked fluid.

Location of the thermal signature is within a meter, but migrating fluid inside the interstitial area can result in an erroneous location if the leak location is not recognized before fluid migration results in a temperature anomaly where fluid collects.

Another fiber optic technique is acoustic detection which monitors the pipeline for acoustic emissions associated with a leak. Sensors are sufficiently sensitive that they can reproduce the sound of a shovel stroke in sand 100 feet from the sensor or footsteps in the right-of-way (ROW). This method provides good right-of-way encroachment protection as well as the opportunity to detect soil percolation and other evidence of a leak. Commercial applications can ignore unexpected vehicles crossing the ROW, but issue an alarm if one travels in the ROW for a period of time if it is not scheduled to be there. This method is also suitable for detecting seismic activity.

Fiber optic techniques can also be deployed as a continuous strain gage to monitor deformation of the pipe due to shifting soil. It can also be deployed separately to detect soil shift in the vicinity of the pipe where ground faults are known to exist.

New fiber optic technology includes cables whose cladding is affected by contact with petroleum products. There are several discussions regarding this capability available on the Internet. However, any identities of commercial products offering this technology remain elusive.

Fiber optic technology offers the potential to provide leak detection at a greater sensitivity and shorter detection time than may be possible using other technologies, and with fewer false alarms. However, fiber optic solutions require detailed engineering to ensure their success in unique pipeline configurations and ambient environments. Design goals must include the following:

- Protection from adverse environmental influences that may result in physical harm to the cable,
- Immunity from stimuli resembling that of a leak under normal operations, and
- Reliable recognition of stimuli indicative of a leak under actual leaking conditions.

It should be recognized that the performance of DTS, and any other technology that detects fugitive fluid, cannot easily be correlated with a particular leak rate. However, estimates are possible by calculating the propagation of heat (or fluid) toward the sensor under leaking conditions. Because fiber optic techniques of all kinds do not require a minimum leak rate, but only recognition of evidence indicating a leak, it is possible that this technology is a good substitute for meter-based techniques where flow measurement is impractical, and is a good technology to extend sensitivity and locate potential leaks when deployed with a meter-based system. When used as a primary leak detection method, care must be taken to assure any leaked fluid will provide evidence of the leak to one or more available sensing cables.

5.1.3 Static Pressure Tests

Static pressure tests were traditionally performed by shutting the line in under pressure, waiting for the fluid to achieve environmental temperature, then monitoring pressure for further decay. A more modern approach is to shut the line in under pressure, then monitor the pressure decay due to temperature change. Once a pressure change is noticed, some pressure is released and the pressure decay is monitored again. If no leak exists, the pressure decay during both intervals should be consistent with heat migration to the environment. If a leak exists, there should be a slower pressure decay at the lower pressure, thus indicating a leak. This is especially true for liquid lines where pressure loss due to a leak would be much more rapid than due to density change as temperature decays. This can be implemented as a manual operation or an automated procedure using the SCADA system or station equipment. A minimum of one

(1) pressure sensor is required in each isolated, pressurized segment to support this test. Typical issues with this procedure are valve integrity (leaking through), availability of fluid for pressurization under control of jockey pumps, and/or management of the pressurization during the pipeline shutdown from flowing conditions. This concept applies to both liquid and gaseous pipeline applications, but at very reduced sensitivity for gaseous pipelines. It is not a recommended solution for gas or multiphase pipelines because expansion of compressible fluids tends to mask otherwise recognizable pressure anomalies. However, in any environment, its sensitivity will be greater than would be possible under flowing conditions.

5.1.4   Double-Wall Pipe

Installation of double-wall pipe is frequently thought of as simply a method of containing fluid from a leak on the inner wall. While this is true when the outer wall is capable of resisting the hydraulic effects of a significant rupture of the inner wall, it offers opportunities for leak detection by methods not normally available in commercial products. These methods have the potential of combining fluid containment with sensitivity far greater than provided by usual leak detection methods. The reason for the increased sensitivity is that the mere presence of fluid in the annulus, or interstitial area between walls, can be detected regardless of the time required for its migration into the annulus. Leak detection, by monitoring the annulus for pipeline integrity, must consider several goals. These are:

- Whether leak location is desired,
- Whether a leak in the outer wall should be detected,
- What fluid(s) may be leaked, and
- How recovery from contamination would be addressed.

If leak location is desired, a method that does not merely detect the presence of contamination is desired. Physically segmenting the pipe, combined with methods such as fiber optic DTS technology, can locate the leak to a minimum resolution of the physical segment length in the case of pooling fluid collecting at the lower end of the segment and up to one (1) meter resolution where the DTS system is affected by the fluid where it is released. For large leaks, the fluid temperature is expected to warm the outer wall directly. For smaller leaks, released fluid may approach outer wall temperature before the DTS fiber sees a temperature change. In such a case, any released fluid is expected to eventually conduct heat and/or destroy the insulation between the contained fluid to the outer wall and the DTS fiber.

A vapor collection system can provide leak location provided the sampling method preserves the location of the vapor in the sampled air stream. Such a system must able to either operate under line pressure or sense its failure due to excessive pressure preventing proper sampling. Monitoring annulus pressure, if the annulus is closed, will not provide evidence of leak location. Vapor sensing systems on the surface are sometimes confused by vapor sources other than the pipeline, especially in industrial areas or in areas with many nearby pipelines.

If a leak in the outer wall must be detected, DTS again provides a solution due to the increased heat conductivity through the flooded annulus. Unfortunately, any outer wall leak location resolution is limited to the length of the physical segment boundary because the seawater temperature is substantially the same as the original outer skin temperature. Closed annulus pressure monitoring can provide evidence of a leak with some variation expected as the environmental temperature varies. Drawing a partial vacuum on the annulus can reduce pressure variations due to temperature and make any unexpected pressure rise more recognizable. No hydrocarbon vapors will be present due to an outer wall leak.

Gas leaks are expected to initially lower the skin temperature of the outer wall, first at the leak site, then throughout the segment as the expanded and cooled fluid mixes with the original fluid contents between pipe walls and migrates outwardly.

Oil leaks are expected to warm the outer wall at the leak site and below as liquids pool. For small leaks, the first sign of a temperature rise may be at the pooling location where oil may have lost much of its original heat during migration downward. Once pooled, the oil serves as a heat conductor between the contained fluid and the DTS system. For large leaks, such as a sudden rupture, the initial pressure differential may cause released fluid to flow around the inside surface of the outer wall, thus carrying heat quickly to the DTS fiber regardless of its circumferential position.

Should a mixture of hot crude and cooling gas be leaked, it is expected that the temperature at the leak site may be unpredictable, though it will probably change to some degree. However, should warm oil drift downward replacing air and cooled gas, the temperature profile should evolve to show a higher temperature below the leak and cooler temperature above the leak until the annulus pressure approaches pipeline pressure, and temperatures stabilize. When this occurs, the major temperature anomaly will be where liquid provides better heat conductivity to the outer skin from the contained fluid than does the compressed gas above it.

Hydrocarbon sensors can be deployed in the interstitial space if desired, subject to restrictions related to maintenance and reliability. Deployment of such tools should be done only with assistance of the vendor's engineering team to ensure all potential problems are recognized and dealt with.

  As described above, oil leaking into the annulus can result in a thermal event that can be detected by DTS technology provided the design and deployment of the system supports that level of performance. However, it is prudent to monitor the annulus for the presence of fugitive fluid by some means in order to ensure recognition of a slow-developing leak by at least one method. A closed annulus with respect to end-caps could employ pressure sensors, or vapor sensors if air can be drawn through the annulus. It is important to remember this report is not intended to declare any particular technology or method to be universally applicable. Instead, each pipeline's leak detection systems should be outfitted with tools appropriate for that pipeline.

Plans for recovery from a leak event must address resumption of leak detection when the line goes back into service. Any repairs to the double-wall segment contaminated by a leak must include cleaning the entire segment if the leak detection method would be adversely affected by oil residue. External monitors, such as fiber optic DTS, simplify repairs of the pipe, but the fiber must still be redeployed and tested before production continues.

6.0   CONTROLLER TRAINING

Training in the use of information provided by any leak detection system is critical to the success of any pipeline integrity monitoring program. Rather than simple cookbook style steps to take when certain events occur, a culture of concern regarding pipeline integrity and due diligence must be the basis of an effective training program. Controllers should be trained sufficiently that recognition of a potential leak is instinctive.   Control Center management should have a greater priority on pipeline integrity management than production. Only then can the controller feel free to shut down the line for further testing when a leak is suspected. Static pressure tests, where possible, are preferred over analysis under flowing conditions once the persistence of the leak evidence indicates it is probably not the result of a transient condition.

When a leak is suspected at any particular point on the line, the controller should have formal procedures to place the pipeline in the safest configuration for the suspected leak location. All necessary contact information should be at hand to facilitate rapid deployment of response teams. Controllers should be expected and trained to err on the side of caution, but suffer no penalties for reasonable judgment. When possible, second opinions should be sought, but not at the expense of a rapid response.

7.0   TECHNOLOGY OPTIONS

There are many choices among leak detection technology options. There always exists a cultural bias in pipeline companies toward using technology with which the staff is comfortable, or technology that served them well for decades. In some cases where staff is proactive by nature and eager to embrace new, but proven, technology, the more capable solutions along with good instrumentation are deployed. In other companies there is resistance to change, both in cost and comfort level. There are two (2) basic viewpoints at work. One involves the probability of a leak with expectations that any damage will be absorbed over time and prudence dictates adherence to applicable regulations and minimum industry practices. Some companies in this camp are not fully aware of the risks or their narrow view of options worthy of consideration. Some believe they are industry leaders. Other companies, who are less courageous when it comes to accepting risk, but are unafraid to embrace new technology, tend to deploy new technology on a more frequent basis in order to have the best leak detection possible. The difference is largely driven by business decisions based on the perceived benefits of investment in leak detection technology. Companies with vast networks tend to believe it is more appropriate to absorb the impact of any incident rather than attempt to control the impact of an incident by investing in costly top-of-the-line systems along with its supporting infrastructure. Some avoid improving their level of sophistication where it is needed on particular lines because of a perception that the new technology will be expected to be deployed on all pipelines, even where the benefits on some lines may not be significant.

There are many considerations. Directions taken are usually influenced by experience along with confidence, courage, and desire to be respected by management and peers. It behooves the company to ensure the technical staff keeps up with available technology and feels free to recommend new solutions as the needs arise.

8.0   ADEC 2011 LEAK DETECTION CONFERENCE PRESENTATION ANALYSIS

Presentations at the 2011 Leak Detection Conference covered a range of topics including discussions regarding the reasons for known difficulties in achieving reliable and rapid detection of leaks on Alaskan crude oil lines, leak detection products, and commercially available instruments in support of leak detection.   There was little discussion regarding actual implementation or deployment of products specifically on flow lines. However, with appropriate infrastructure support, solutions can be engineered to apply the technologies discussed in the conference.   The following sections describe various presentations, along with the evaluator's comments regarding the applicability of the concepts or products being discussed.

8.1   Session 1: Pipeline Leak Detection (PLD) Technology Users Group Panel Discussion

The following presentations describe considerations in selecting and operating leak detection systems in Alaskan environments. The presentations were offered by users with experience in Alaskan pipeline operations and leak detection.

8.1.1   Presentation 1 – Key Metrics in Selecting, Deploying, and Supporting a CPM PLD System on the North Slope
         (Dave Alzheimer – ConocoPhillips)

This presentation by Dave Alzheimer described some of ConocoPhillips' experiences with leak detection. The website is http://alaska.conocophillips.com. Major points included the following:

1. PLD Systems are a marriage of components that must be considered individually and as a group. Failure of any component can adversely affect leak detection success. Individual components include process instrumentation, data interface, leak detection algorithms, and the Human-Machine Interface (HMI) for the pipeline controllers.

2. Pipelines are unique with respect to flow rates, static conditions occasionally, presence of slack flow, fluid properties, and temperature. Temperature can have a major effect on leak detection.

3. Calibration of instruments is important.   Meter accuracy is a limiting factor regarding leak detection performance.

4. Communication requirements in support of necessary data throughput were discussed.

5. Selecting the correct algorithm for the hydraulic process was stressed.

6. Testing with fluid withdrawal was discussed. Validation of the system's capability is important.

7. The system's handling of bad data should be considered. How a system handles abnormal startup and shutdown sequences should also be considered.

8. False alarm prevention is important.

9. Vendor-supplied diagnostic tools should be a consideration.

10. Stand-alone HMI and options for integration with SCADA HMIs were discussed.

11. Alarm generation, trending, and other functions were discussed.

12. Vendors should be prescreened with respect to their history on pipeline similar to yours and consider having a sensitivity study including leak tests on retrofits. Avoid commitments until you verify the system is suitable for your pipeline.

13. Consider the vendor's software release frequency.

14. Consider the ability to replay leak events for training purposes.

Evaluator's Comments:

The presentation was a well-rounded explanation regarding how to avoid the most common mistakes and missteps that occur in deployment of a leak detection system that ultimately results in less than desired performance. Efforts to minimize costs by selecting a vendor largely on a cost basis are usually unsuccessful because vendors of products that have limited sophistication know they have to compete in the business arena rather than on a technical basis. Vendors whose products are mature and highly capable are more willing to compete on a technical level, but usually for a reasonable price that reflects the benefits provided by their system. However, there is competition at the highest levels.

To expand on the topic of integration, it is generally important to define the level of integration desired with other systems and produce a functional specification and invitation to bid. Dominant vendors are all adept at integrating their leak analysis results with SCADA systems in order to efficiently draw the controller's attention to the leak alarm. The specification should address any preferences pertaining to the topics listed above. Unlike "concrete and conduit" project specifications, vendors should be expected to take exception where their product does not fully comply with requirements. Vendor proposals should be evaluated based on perceived value and project risk. Pilot projects are a good way to determine a system's capability, especially if the most difficult line is used for the pilot.

8.1.2 Presentation 2 – Difficulties with Maintaining CPM Leak Detection System During Times of Low Flow
(Morgan Henrie, PhD/PMP – MH Consulting)

This presentation by Dr. Morgan Henrie, representing Alyeska Pipeline Service Company, described problems encountered under low flow conditions. The website is http://www.alyeska-pipe.com. Significant points included the following:

1. The throughput of the Trans Alaska Pipeline System (TAPS) pipeline started at 700,000 barrels per day (BPD) and is declining around five and six-tenths percent (5.6%) per year.

2. API-1164 equations were discussed with an explanation of the inverse effect of detectible leak size and flow rate.

3. Uncertainties of measurements and their contributions to performance were discussed.

4. The effects of slack line flow were discussed. Recognizing slack line flow is necessary. Elevation changes combined with decreased flow creates greater opportunity for slack line flow.

5. The challenge is to continue to meet the one percent (1%) of daily flow obligation while flow is declining.

Evaluator's Comments:

The presentation provided insight into the challenges dealt with by the TAPS leak detection system and how these challenges are expected to grow until, and if, new production increases throughput. While the number of recorded topics is small, a great deal of detail was provided. While the TAPS pipeline leak detection system encounters significant challenges due to hydraulic behaviors that are aggravated by the pipeline operation and terrain, these problems are unique to the TAPS pipeline <u>only</u> with regard to their unique influence on the particular pipeline. Other pipelines in Alaska can encounter similar challenges under typical conditions.

The 1% of daily flow requirement as expressed in the Alaska regulations has a qualifier: *if technically feasible* that eases the low flow problem to some degree. The increased slack-line flow at lowers flows will require additional pressure and flow measurements on the pipeline to maintain leak detection performance as good as conditions allow. "Technical feasibility" should not be taken to presume performance limits imposed by inherent characteristics of any particular leak detection product and its implementation. Instead, it should be interpreted to reflect the actual hydraulic characteristics and fluid behaviors matched with the most capable leak detection product for the hydraulic conditions.

8.1.3   Presentation 3 – Challenges to Operating/Selecting a PLD on Kenai to Anchorage Pipeline
(Gillus Moore – Tesoro Alaska Pipeline)

This presentation by Gillus Moore, representing Tesoro Alaska Company, dealt with experience selecting a leak detection system and operating a products pipeline in Alaska.   The website is http://www.tsocorp.com. Specific topics included the following:

1. Tesoro considers its products pipeline more challenging than its crude oil lines.

2. When selecting a system, understand what there is in the way of equipment, instrumentation, and uncertainty in measurements.

3. Temperature is a huge impact.

4. Personnel monitoring leak detection and the required skill set were discussed. The question should be asked regarding what responsibilities do personnel have to determine whether an alarm is false or a legitimate leak.

5. Fluid dynamics can be a problem, especially when vendors and their software do not know what is happening along the pipeline between measurements.

6. Know your budget.

7. Know what performance is required. Know that rapid detection and high sensitivity both go against a low false alarm rate.

8. The choice of detecting leaks while shut in, or not, was discussed.

9. Redundancy was discussed. Deployment of different types of leak detection may be the best option for high consequence areas.

10. Whether leak detection during transients is required was mentioned.

11. New pipeline installations provide opportunities to deploy external leak detection systems.

12. Tesoro ships gasoline, diesel, and jet fuel to Anchorage in a 10-inch pipeline. A 40°-temperature differential from one end of the line to the other may occur when injecting jet fuel. Even with high quality Coriolis meters, false alarms are a problem. The line goes slack occasionally. Batch changes can cause false alarms.

13. The shorter crude oil lines are less of a problem, but automatic transfers from tankage have to be monitored.

Evaluator's Comments:

This presentation provided a detailed example of thermal conditions that can thwart efforts to operate a leak detection system at a high sensitivity level with a low false alarm rate. The jet fuel example illustrates the problem of uncertainty in the linepack due to a significant change in the density of the fluid as it travels to Anchorage.

The comment that the vendor can struggle to understand the fluid dynamics and how to effectively deal with them was significant. Some vendors of products using simple algorithms are not fully aware of their limitations. It is not uncommon for some vendors to explain that temperature is an insurmountable problem even though more sophisticated thermal modeling provided by other vendors can accurately estimate the fluid density profile along the line and minimize false alarms. Comment 12 above illustrates the fact that good metering cannot overcome apparently simplistic linepack analysis.

8.1.4   Session 1 Follow-Up

Questions and Responses

Question 1 from the evaluator dealt with recommendations regarding whether or not to have a policy of a static pressure test when an alarm occurs, whether this is not feasible with frequent false alarms, and to what degree the controller should be involved in determining whether an alarm is legitimate.

> One responder described having documented procedures for such evaluation and predefined controller responses, including evaluating the severity of the alarm.

> Another described the operator having the choice to shut the line down any time he feels pipeline integrity is suspect. The operator has tools to help evaluate the validity of a leak alarm. The potential for an alarm caused by a pump control or other stimulus was mentioned. Options include driving or flying the line if deemed necessary. A concern is that frequent shutdowns and startups may be hard on the pipeline, too.

> A third response indicated his experience is that the controller investigates the validity of an alarm and can escalate the alarm if its validity remains questionable.

The evaluator commented that, with a senior controller who knows the pipeline's hydraulic behavior well, the sole purpose of the leak detection system might be to draw the controller's attention to a hydraulic anomaly that might otherwise be missed.

The evaluator commented on the obsolete API-1155 that was intended to allow comparison of various leak detection products on a particular pipeline, adding that many vendors did not want to be compared to their competition so the concept never matured. However, one API-1155 experience where one vendor found none of three (3) leaks and another found all three (3) leaks demonstrates the importance of verifying the suitability of a leak detection tool for the target pipeline.

Another question from the evaluator pertained to restricting flow downstream of a potentially slack area to maintain sufficient pressure along the line to avoid slack conditions.

> One response indicated that there are some locations where efforts to manage slack conditions may carry their own risk. A potential solution is to add instrumentation to help locate and quantify the slack area better. An opinion was expressed about the importance of sharing pipeline data with candidate vendors in order to determine their level of performance on the target pipeline. Pipeline operating companies should expect to pay for this.

The evaluator described the thermal issues on a project where crude oil from tankers varied among ships and the leak detection system's thermal model was able to track fluid properties due to heat migration with the added complexity of the environment temperature changing between batches. Batch interface positions were accurately predicted as fluid expanded and contracted.

From the audience: A question was asked regarding pipeline traversing populated areas and any special requirements.

> A response indicated that it is a federal requirement that high consequence areas be identified and dealt with. The audience was reminded that leak detection systems do not prevent leaks, but hopefully they will detect them quickly. Management should be more concerned with preventing leaks.

The evaluator described his experience dealing with special considerations over the Edwards Aquifer Recharge Zone, including hydrocarbon sensing cable, shortened meter-bound segments, etc.

From the audience: Another question pertained to the cause of actual leaks in Alaska.

> The responses mentioned corrosion and valve leaks. ROW incursion and construction have not been a problem in sparsely populated areas. TAPS uses three (3) leak detection methods, including a real-time model, line balance over an extended period of time, and pressure/flow deviation. An explanation of the controller's analysis and the overall time from the leak alarm to the controller's decision regarding leak validity was provided.

The evaluator described a situation where the policy was that any leak alarm required the line to be shut-in and tested. This resulted in high alarm thresholds to prevent false alarm. A leak "warning" level was provided by the vendor to allow sensitive operation while preserving the alarm protocol for responding to leak alarms rather than warnings. He described the problem of a false alarm per month for ten (10) years and the potential for a valid leak alarm to be ignored during the eleventh year.

From the audience: A question was asked regarding testing of the existing leak detection system.

A response indicated that ongoing testing is a normal activity. In some cases, performance improved over the years. The critical issue for performance is to understand what is going on in the pipeline.

Another response indicated ongoing testing is essential in understanding the state of the system and its continued ability to detect leaks.

The evaluator described a company that does periodic response tests including involvement of regional first responders. But, the tests were never a surprise because the corporate safety officer always flew in to witness the test, and for no other reason.

From the audience: A question was asked regarding what measurements are needed beyond flow measurements to do leak detection well.

A response indicated it was common to use pressure and temperature correction to determine net flow values.

Another response indicated there are a number of uncertainties involved in leak analysis.

8.2   Session 2: Meter Based PLD Technology and Related Practices

Session 2 was scheduled for late morning and the afternoon of the first day. The first six (6) presentations focused on leak detection products available commercially for consideration on crude oil pipelines. Presentation 7 (Section 8.2.7) explained the impact of temperature variations under dynamic flow conditions.

8.2.1   Presentation 1 – ATMOS Pipe and ATMOS Wave
(Michael Twomey – ATMOS International)

Michael Twomey described the ATMOS Pipe and ATMOS Wave leak detection tools. The website is http://www.atmosi.com. Presentation slides are available as Appendix B in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Main topics included the following:

1. ATMOS has systems installed on over four hundred (400) pipelines, as short as a few hundred meters to networks over 8,000 kilometers long.

2. They support gas and liquid operations.

3. The presenter agreed that no one solution is the best for all pipelines and, therefore, ATMOS has been developing additional technologies to meet a variety of needs. ATMOS Pipe is a statistical mass balance system and has been in place for over fifteen (15) years and ATMOS Wave detects the rarefaction wave generated by a sudden leak and has been in use for two (2) years.

4. ATMOS is now providing a real-time model with ATMOS Pipe.

5. ATMOS produces hybrid systems based on their products integrated to take advantage of each one's strengths.

6. Some countries have passed the U.S. in government regulations. Some require the ability to measure fluid losses, thus making the mass balance capability important in any installation. This requires an accurate and sensitive mass balance component.

7. ATMOS has also provided training simulators, batch tracking and pig tracking applications, and pipeline optimization systems.

8. Examples of installations were described.

9. One system is in operation so deep in water off the coast of Mexico that any leak would result in water leaking into the pipeline. Consequently, they have ingress detection as well leak detection on that line.

10. ATMOS brings a significant base of experience in pipeline leak detection from around the world.

11. ATMOS Pipe uses patented statistical algorithms along with their corrected mass balance method to reliably detect leaks. The trick is to be able to distinguish between transients and real leaks.

12. ATMOS Pipe has been installed on a variety of pipelines including gas, refined liquids, crude oil, chemical, carbon monoxide, LNGs, etc.

13. ATMOS Pipe has a very low false alarm rate and does not require as much instrumentation as other tools.

14. ATMOS' preference is to display leak information through the SCADA system as the primary method of drawing attention to the potential leak. They provide diagnostic tools to confirm alarm validity.

15. ATMOS Pipe learns the long-term drift of meters so false alarms are not produced by meter drift.

16. ATMOS Pipe does not do detailed hydraulic modeling in its basic form.

17. ATMOS Pipe is OPC compliant for easy integration with other systems.

18. Diagnostic tools exist to help identify instrument failures.

19. A version of ATMOS Pipe is deployed in several international airports to monitor fuel systems using static pressure tests.

20. Leak thresholds are not desensitized to deal with transients. Persistent imbalances after integrity verification are not problematic because the system understands them.

21. Scans are usually every five (5) seconds.

22. The statistical method was discussed to illustrate assessment of the probable presence of a leak.

23. The effects of meter repeatability were discussed.

24. The effects of transient operations were discussed with respect to leak probability.

25. Rather than having a flow imbalance threshold to serve as a leak alarm threshold, the system uses a probability that any imbalance is a leak as a basis for alarm generation.

26. An example of a refinery and distribution network was described.

27. Collecting data associated with a batched crude oil network was described. Examples of successful leak tests were described on this line. Many leaks were during transient periods.

28. ATMOS Wave was described. The purpose is to detect leaks instantaneously and locate leaks better than possible with meter-based solutions.

29. Special three-dimensional (3-D) algorithms allow differential pressure measurements.

30. It is an event-driven technology and, therefore, must be active when the leak occurs. It has a very low false alarm rate.

31. It is suitable for theft detection and can detect the closing of a valve, as well as opening.

32. ATMOS Wave is usually deployed with pressure sensors at each end of the segment with Global Position System (GPS) devices for time stamping data. Data is sent to a central server for analysis. Data is sent by OPC to SCADA, including rough estimates of leak size based on pressure wave characteristics.

33. Test results were described for a line that ran intermittently. A 3.42-liter leak was detected in ten (10) seconds.

34. The presenter cautioned the audience against taking reported performance results from any test in terms of percent to be an indication of performance on any other pipeline because each pipeline is different. What is usually desired is to know what size leak can be detected all the time with no false alarms.

35. On an 83.9 kilometer long, 18-inch line in Mexico transporting gasoline and diesel, twenty-two (22) leaks were each detected in under two (2) minutes. Leak sizes ranged from one-half percent (.5%) upward, and leak locations were around two percent (2%) of the line length.

36. No two (2) pipelines are the same. Using multiple tools is a good idea. Single solutions may not be the best option.

Questions and Responses

The evaluator asked if the system uses valve alignment to sense shut-in conditions and how fast can it detect a leak under shut in conditions.

> The presenter gave examples of airport hydrant systems where requirements included detection of a two (2)-liter loss.

The evaluator asked if the system was able to operate at much greater sensitivity under static conditions since lost fluid is not being replaced under static conditions.

The presenter explained that the system is using only pressure in that case, so sensitivity would be greater, but the difference depends on the pipeline. Detection time is in minutes.

The evaluator asked about learning meter drift and the learning process at different flow rates. At what point do we decide a meter change is a drift or an indication of a leak?

The presenter explained there is a "forgetting factor" and that the learning process has a very long time constant to prevent learning a leak condition is normal. Tuning this depends on pipeline characteristics.

The evaluator suggested that the learning process is probably suspended in the presence of information suggesting a leak exists.

The presenter explained that learning is halted as soon as the system sees a small increase in leak probability resulting from a transient.

The evaluator asked how the system learns many different operational conditions.

During tuning, the system switches among flow conditions and continues the learning process for that condition automatically.

Evaluator Comments

ATMOS Pipe is an extremely popular leak detection system due to its record of low false alarms and predictable performance using meter-based mass balance algorithms. The system's strengths include their sophisticated leak probability algorithms, as well as their method of analyzing excursions away from usual quiescent states of the pipeline hydraulics rather than using absolute measurements. The system has been known by the evaluator to replace an early real-time transient model (DEC PDP vintage) and its successor after the successor's poor performance rendered it unusable. ATMOS Pipe's performance in this highly transient, but small pipeline network, was deemed acceptable by the operating company and regulators.

While ATMOS Pipe has a very good record on highly transient systems before their development of a RTTM component, the use of a RTTM's thermal model should improve the system's understanding of the linepack and, therefore, shorten detection time and limit the spilled volumes further. Exploring the options and value of their RTTM module is recommended.

8.2.2   Presentation 2 – PipePatrol Leak Detection and Localization System (fka Galileo)
(Daniel Vogt – Krohne Oil and Gas)

Daniel Vogt described the PipePatrol (aka Galileo) leak detection tool.   The website is http://www.krohne.com. Presentation slides are available as Appendix C in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Main topics included the following:

1. Krohne was founded in Germany in the 1920s and now has 2,500 staff members in numerous offices worldwide.

2. In 2000, German regulations were stiffened to require new pipelines to have leak detection systems, resulting in the development of PipePatrol. It now exists on ninety (90) pipelines worldwide.

3. The definition of a good leak detection system is measured by metrics described in the former API-1155 (now described in API-1130).

4. Sensitivity is one (1) metric of performance. This includes the measure of the smallest detectible leak rate dependent on instrumentation deployed and the measurement quality. *"You cannot find a leak smaller than you can measure."* The time required to detect the smallest detectible leak is another component of sensitivity. The detection time is dependent on the algorithm used.

5. Reliability is a measure of the system's ability to always detect real leaks and never generate false alarms.

6. Robustness is a measure of the system's ability to operate in a condition where data quality is degraded such as when an instrument has failed.

7. Accuracy is a measure of the system's ability to measure the quantity of fluid lost, as well as estimate the leak's location.

8. Reliability is most important because frequent false alarms will cause the controller to lose confidence in the system and potentially ignore a valid leak alarm.

9. An example of a traditional leak detection system on a gas pipeline was presented. The example involved an imbalance between injections and deliveries. If this imbalance is not the result of a leak, but meter accuracy, any leak detection threshold must tolerate this, thus decreasing sensitivity.

10. PipePatrol's e-RTTM means extended Real-Time Transient Model. It calculates a virtual pipeline model using boundary measurements from the real pipeline to generate pipeline profiles.

11. The system solves equations for conservation of mass, momentum, and energy.

12. The virtual pipeline is leak-free and thus is compared to the real pipeline to look for evidence of a leak.

13. The model eliminates the effects of startups and shutdowns and other transient conditions.

14. Statistical processing looks for leak patterns.

15. False alarms are avoided.

16. Differences between the virtual pipeline and the real pipeline appear in decision values that will indicate pipeline condition.

17. A description of non-leak signatures and leak signatures was provided with charts showing results. The system keeps a database of non-leak signatures for reference when evaluating evidence of a potential leak.

18. The system uses three (3) leak location methods. The first is based on the gradient intersection method. The second is based on the change in the relationship between pressure and flow. The third and most accurate is based on the time-of-flight of the pressure wave caused by the leak.

19. Leak tests on a 10 inch 31 kilometer long, bi-directional multi-product pipeline operated at 40 BAR were described.

20. Full instrumentation was typical with additional soil temperature measurements provided at each end. Fluid was extracted and metered at valve sites for leak tests. Leak flow was 0.08 percent (.08%) of flow.

21. Measured values reflect the leak while the virtual pipeline did not, thus showing the leak condition in the difference.

22. Data is propagated to SCADA for alarm presentation.

23. Leak parameters were listed and explained.

24. All leaks were detected within thirty (30) seconds and alarmed within one (1) minute.

25. Leaks were .08 percent (.08%) of design flow and one and one-half percent (1.5%) of nominal flow. Accuracy of leak location was approximately 1.2 percent (1.2%) of the pipeline length based on time-of-flight. The gradient method was accurate to 1.59 percent (1.59%).

26. Released volume was eighty-six (86) liters; less than a half barrel for all three (3) trials.

27. Integration with SCADA is common. OPC is supported.

28. More pipeline examples were described.

29. Krohne provides flow computers, instruments, and communication gear.

30. Monitoring stations collect data from the field and perform analyses.

31. TCP/IP is supported for field data.

32. Controllers tend to not want to interact with the leak detection system. Krohne can provide only a leak alarm to the controller with constituent data available on the leak detection system's HMI for further analysis.

33. System status is available, including pipeline flowing status, subsystem status, instrument status, etc.

34. Leak parameters are presented on the HMI.

35. Temperature, density, and pressure profiles are available on the HMI.

36. The RTTM provides a great deal of data.

37. Efficiency analysis is available.

38. Pipeline inventory is tracked.

39. Each field measurement is validated by the instrument analysis component.

40. Data frozen by communication outages is detected and alarmed.

41. The system can identify when and where slack line occurs. An alarm is generated when the line goes slack, but a false leak alarm is not generated.

Questions and Responses

The evaluator asked about sensitivity and persistence levels; specifically to determine how many observation windows can be configured.

> The presenter explained that there are four (4) sensitivity levels. Transient operations cause the system to switch to a higher sensitivity threshold (less sensitive). Sensitivities are configurable for each pipeline.

The evaluator asked if the system can continue to operate when slack line conditions exist.

> Yes, but sensitivity would be very low. A rupture would be detected, but not a one percent (1%) leak.

The evaluator asked the presenter to describe what thermal parameters are configurable and how Krohne would configure thermal parameters with the pipeline company's help.

> The presenter explained that he did not know the particular parameters configured to model heat transfer, but indicated parameters would be configured individually for each modeled segment along the pipeline because environmental conditions vary every few hundred meters. There are standard parameters for some elements such as thermal properties of steel, but other parameters are derived during tuning.

The evaluator suggested that Krohne probably provided this configuration service on a regular basis.

> The presenter confirmed this was true. Krohne commissions the system with low sensitivity and collects data for three (3) months, then tuning is based on collected data.

Evaluator Comments

The evaluator did not have previous experience with PipePatrol on actual projects. However, the performance record provided in the presentation and its underlying technology indicate it would be a worthy competitor for selection on liquid pipelines that operate at elevated fluid temperatures and with temperature declines typical of Alaskan pipelines. The description of bi-directional pipelines with batches of several different products suggests the system expertly handles the adverse influences that would thwart good leak detection performance using less sophisticated meter-based systems. The less capable systems often merely tolerate these influences by elevating detection thresholds and/or increasing detection time to confirm persistence of the leak evidence. By modeling the pipeline, this system decreases linepack uncertainty and, therefore, has an opportunity to develop confidence in evidence of a leak much sooner than could be done using non-model based systems. The presenter's comment Number

4 above illustrates the point that meter quality determines sensitivity by establishing the best degree of balance accuracy while the algorithm significantly affects detection time by tolerating, or in this case minimizing, linepack uncertainty. This tool is of a class that would handle the temperature issues known to be a problem for other systems in Alaska.

8.2.3   Presentation 3 – TCS "Tightness Control System"
(John Birnie – Hansa Systems, LLC)

John Birnie described their leak detection tools, including TCS or Tightness Control System. The website is http://www.hansaconsult.com. Presentation slides are available as Appendix D in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Main topics included the following:

1. Hansaconsult has a hydrant leak detection system in the Anchorage Airport complex. Primary interest is in the aviation fueling system, but SCADA and HMI work has evolved.

2. Projects involve several countries. They work with any contractors or subcontractors on projects.

3. Hansa is ISO 9000 certified and works with aviation standards organizations such as International Air Transportation Association (IATA). They are an associate member of the Joint Inspection Group (JIG).

4. TCS was developed as a response to a 1982 incident at the Frankfurt airport.

5. TCS is based on a pressure step method.

6. Federal and other regulatory organizations can be lax with respect to requirements. Some companies are becoming more proactive to reduce the cost of insurance. The Anchorage airport sought enhanced capabilities with the expectation that regulations may, or may not, exactly fit their chosen solution.

7. Germany requires leak detection on hydrant fueling systems at about 0.04 liters per hour leak rate per cubic meter of pipe volume at 7-BAR pressure (105 PSI).

8. TCS has three (3) parts, but the presentation only dealt with one (1) component. Static pressure testing is available at any time on shut-in pipe segments. The results of these tests often eliminate the need for the sometimes destructive hydro-testing.

9. Testing at the airport usually takes around fifty-two (52) minutes total.

10. Pressure step technology uses about 10-BAR as the first pressure and a target of three (3) gallons per hour leak rate.

11. Some cycles start between zero (0) and 225-PSI on each test with the same pressure each day for consistency with a hold time of thirty (30) seconds. Typically, this is around 50 PSI. Pressure is raised to 150 PSI where it is held for settling for ten (10) minutes before a two (2)-minute observation interval. Then, pressure is decreased to 50-PSI and held for ten (10) minutes before another two (2)-minute observation interval. Pressure is again increased to 150-PSI for another sample.

12. The temperature influence on pressure will be seen as a consistent drop at the two (2) pressures because density changes due to heat transfer are not dependent on pressure. However, any pressure decrease due to a leak will be different between 50-PSI and 150-PSI. Such a difference is indicative of a leak.

13. Sometimes the temperature at the low cycle can increase if cold fluid relative to the environment is injected, thus resulting in increasing pressure as temperature rises when testing during sunny days.

14. TCS only needs a means of pressurizing the line.

15. They have a proprietary 22-bit A/D converter. Rosemount 3051 S transmitters are approved.

16. Continued expansion and contraction of the pipe after pressure excursions was explained. In the high-to-low case, the pipe contracts and an increase in pressure may occur. In the low-to-high case, the pipe continues to expand after pressure is applied and pressure sometimes drops.

17. Aboveground lines can have diurnal influences. Rain can create problems during a test.

18. All that is needed is a method of pressurizing the line.

19. Leak tests use orifice places with holes from 6- to 21-thousandths of an inch in diameter.

20. The system can run on the SCADA computer and communicate with SCADA via OPC. Tests can be automated.

21. The portable system can be brought to remote sites for annual tests.

22. Double block and bleed valves are preferred.

23. "False" alarms are usually indicating a leak through valves.

24. Truck and trailer mounted units are very portable.

25. Service includes results analysis.

26. Logging in remotely to examine data is a service option.

27. Leak tests are usually at the rate guaranteed by the company.

28. Paint spraying nozzles can serve as orifice plates.

29. Leak sizes are estimated using fluid characteristics, and test pressures.

30. Considering the sample pipelines described in the Request for Information (RFI), this is not an area they are in right now, but they were asked if their technology could be adapted. They do not expect to be applicable to large aboveground North Slope lines with natural gas contents because of its compressibility.

31. Filling lines with water would result in finding very small corrosion holes.

32. Kleopatra is an RTTM that is under development.

Questions and Responses

The evaluator explained his experience answering the question, "How much fluid would be lost in a month if the leak rate was only ninety percent (90%) of the minimum detectible rate?" Losses could be staggering. Shut-in pressure tests became the norm on this line when the line was not operating. He added that tools of this kind have a place in managing pipeline integrity.

The evaluator asked if, during the two (2)-minute observation interval, the system looked at the rate of change during the interval.

> The presenter explained that they sample pressure every two (2) seconds and look at the rate of change during the interval.

The evaluator repeated the concept behind the pressure step method and the presenter added details such as the influence on pipe expansion, etc.

The evaluator opined that the TCS tool takes into account more parameters and pipe characteristics than would other more basic static pressure analysis tools.

> The presenter told a story of a daytime leak test in Florida where pressures were seen rising during a five (5)-gallon per hour leak test. The system recognized the fluid withdrawal in spite of the increasing pressure caused by the sun's influence on fluid temperature and density.

Evaluator Comments

This system evolved in a particularly sensitive high consequence area before the term HCA became commonplace. It is particularly suited for use where lines can be shut in tightly and be pressurized for testing. While this particular product has not been traditionally deployed on transmission lines, but rather on complex fuel hydrant networks, it could easily be adapted to support interplant lines and terminals with complex piping. Static pressure testing in its basic form has only recently become a common feature in meter-based systems. This tool offers the potential of extending the sensitivity of any pipeline leak detection capability to its lowest detection level during periods of inactivity. Issues that are expected include the cost of the pressurization system and other infrastructure enhancements, such as control elements, tight valves, and proprietary instrument deployment and, in the case of portable operation, the transportation costs. While airport hydrant systems have much more stringent leak detection criteria because of the high hazard environment and sporadic pipeline use allowing time for integrity tests without interrupting operations, they provide an example of what can be achieved if one is really determined to have sensitive leak detection.

An additional benefit of this method is accomplishment of substantially the same verification of pipeline integrity as is provided by hydro-testing, but without the risk associated with the high pressure excursions often required by formal hydro-testing protocols.

Above-ground piping may be more difficult for the pressure step technology because the potentially larger temperature differential between the pipe and its environment may cause more rapid heat flow. However, the benefit of insulation should reduce heat flow much as does the warmed soil around buried

pipe. The expected behavior of static testing for each pipeline segment should be established empirically with allowances for seasonal and weather conditions.

8.2.4   Presentation 4 – LT-100 and HT-100
(Doug Mann – Vista Leak Detection, Inc.)

Doug Mann described the LT-100 and HT-100 leak detection tools.   The website is http://www.vistaleakdetection.com. Additional details regarding the presentation are only available from Vista Leak Detection, Inc. Main topics included the following:

1. They do bulk storage tank leak detection, mostly in North America.

2. They participated in development of EPA standards for leak detection on tanks.

3. Typical performance on pipelines range from one-tenth (1/10) of a gallon per hour to forty (40) gallons per hour, depending on the line segment volume; this for three thousand (3,000) gallons up to a one million-gallon line.

4. Tests are only in static shut-in mode.

5. They provide static pressure tests required in California on numerous buried pipelines.

6. Vista has fixed and mobile systems available.

7. Options include integration with other systems.

8. LT-100 is suitable for lines under three thousand four hundred (3,400) gallons.

9. Testing is performed at two (2) different pressures to allow distinguishing between pressure loss from thermal influences and a leak.

10. Leak volumes are reported.

11. Volume-based tests take around three (3) hours.

12. The volume test involves measuring fluid injection volume necessary to maintain pressure.

13. Constant pressure is normal with the volume test and not an indication of pipe integrity.

14. Reports are generated.

15. The pressure method is least costly and uses decaying pressure to estimate leak volumes.

16. Pressure tests do not hold pressure constant, but evaluate pressure decay.

17. The pressure test requires about one (1) hour.

18. Both pressure and volumetric tests can be provided using software configuration.

19. Good valves are needed.

20. Some customers test annually in California by regulation.

21. Leak location can be done by attaching sensors on the line and analyzing acoustic signatures.

Questions and Responses

The evaluator asked the presenter to expand on their preference of one (1) technique (volume or pressure) over another on existing lines.

> The presenter indicated the volumetric method does not require as much infrastructure in the way of instruments.

Evaluator Comments

This product family also is based on the benefit of non-flowing pressurized testing where flow measurement uncertainty is zero (0) because flow is zero (0). Either of these methods, pressure and volume, could provide integrity verification during period of pipeline inactivity or upon suspicion of a leak.

8.2.5   Presentation 5 – SimSuite Pipeline
(Kelly Doran – Telvent)

Kelly Doran described their SimSuite leak detection tool. The website is http://www.telvent.com. The recording of this presentation and follow-on questions were unavailable for review and documentation herein. Consequently, the collection of main topics of this presentation is limited to a review of the presenter's presentation slides. Presentation slides are available as Appendix E in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Topics included the following:

1. SimSuite is a leak detection system based on a real-time transient model.

2. Additional algorithms include rate-of-change limits, bracketing monitored values (creep alarming), and shut-in pressure testing.

3. SimSuite models slack and two (2)-phase conditions.

4. The model can be used for pipeline design and operator training.

5. One common set of configuration data is used for leak detection and location, power optimization, training simulator, and offline engineering.

6. High fidelity simulation is based on detailed equations for conservation of energy, mass and momentum.

7. Algorithms provide a detailed accounting of the movement of mass and associated energy transfers inside the pipeline.

8. Features include two (2)-phase flow modeling, slack conditions, drag reducing agents, accurate thermal model, and fast execution.

9. Leak location is done by the gradient intersection method.

10. Pembina Pipeline and ConocoPhillips selected SimSuite to replace their incumbent systems.

11. Colonial settled on SimSuite.

12. Marathon-Ashland Oil Company has sixty (60) pipelines, twenty-four (24) tank farms, and two hundred sixty-six (266) different products. Sensitivity thresholds are five (5) times lower than required and detection times are twelve (12) times faster than required.

13. Marathon configured the model for all pipelines and tank farms except for two (2) pipelines.

14. A graph showed leak test results exceeded the Request for Proposal (RFP) requirements and even API-1149 predicted limits.

15. A second graph illustrates a huge reduction in lost fluid before the leak is detected when SimSuite is compared to simple volume balance methods.

16. The Caspian Pipeline project is 1,500 kilometers in length with future throughput of 1.4-MM bbl/day.

17. Three (3) leak tests were performed.

18. An illegal tap of twenty-five (25) to thirty (30) m^3 per hour was detected and located within 10 kilometers of the actual location.

19. SimSuite uses the same HMI natively as Telvent SCADA.

20. Documented processes for leak responses are recommended.

21. During certain operational modes, such as pump starts, alarms may be suppressed or thresholds modified. Controllers should understand such situations.

22. Actual leaks caught include a gasket failure on a Motor Operated Valve (MOV) at a pump station and a five (5)-barrel leak within fourteen (14) seconds.

23. An example of a typical leak response was described.

24. Pipeline operators are required to review and document their capabilities periodically. Refresher training is required.

25. A multi-tiered approach may be required for full coverage of leak conditions that are anticipated. Controllers should know the strengths and weaknesses of all tools deployed.

Questions and answers were not recorded.

Evaluator Comments

SimSuite is known to be a very detailed model with respect to using parameters that might otherwise be considered insignificant. The modeling technology was developed for use in the nuclear power industry and adapted for pipeline applications.

The model is unique in that there is no standard code base. Instead, an executable file is created from the configuration file. This results in a very fast executable program that can typically be processed four (4) times per second. Early implementations of SimSuite occasionally had difficulty dealing with model errors because the hydraulic errors had to be corrected in the code generator. However, as the product matured, such occurrences became rare to the degree that several pipeline companies have standardized on SimSuite and are very pleased with it.

SimSuite is advertised to exceed API-1149 performance limits as described in Comment 14 above. API-1149 results are heavily influenced by the temperature uncertainty used in the API-1149 equations. An accurate metric for temperature uncertainty along the line based on endpoint measurements is difficult to define, especially in environments where fluid temperature varies along the line with the temperature profile dependent on the transit time of the fluid. In such cases, any temperature uncertainty could be very high without the benefit of a thermal model. SimSuite provides such a model and actually reduces uncertainty in the temperature profile along the line. Therefore, a more complete explanation of SimSuite's performance with respect to API-1149 should describe the benefits of their thermal model in reducing the thermal uncertainty that API-1149 would otherwise use in its calculations.

SimSuite offers great opportunities with regard to training controllers as well. It can provide a virtual pipeline on which leaks can be generated without involving the real pipeline. Upset conditions that are to be avoided on the real pipeline can be generated to train the controller to respond appropriately. Managing pipeline assets to prevent Maximum Operating Pressure (MOP) excursions or surge discharges are a common training topic. Controller certification is another common use of the training feature. This tool is also of the class that would handle thermal issues known to be problematic in Alaska.

8.2.6 Presentation 6 – FUS-LDS
(Martin Dingman – Siemens)

Paul Murphy and Rocky Zhang described their ultrasonic meters and their leak detection system. The website is http://www.sea.siemens.com. Additional details regarding this presentation are only available from Siemens. Significant points include the following:

1. Siemens does leak detection and sells meters to others.

2. They do not do leak detection on gas systems, but can measure gas flow.

3. Their meters are accurate down to zero (0) flow conditions and can detect product interfaces and measure fluid properties.

4. They usually use two (2) pairs of clamp-on transducers with a Resistance Temperature Detector (RTD) temperature sensor. They can use the customer's temperature measurement.

5. Clamp-on sensors require no shutdown or pipe penetration.

6. Application diagnostics are provided.

7. The leak analysis tool is a mass balance algorithm using endpoint measurements.

8. Speed of sound is important and necessary to determine fluid viscosity and density. (evaluator note: Information regarding the speed of sound is necessary for the acoustic flow meter calibration corrections)

9. Service for up to eighteen (18) segments is available for one (1) master station.

10. They have multiple integration periods.

11. Compensation for the speed of sound is provided in the meter.

12. The liquident number is the speed of sound in the product at sixty (60°) degrees.

13. Using the liquident number, the product type can be detected.

14. Polling occurs once per minute, so leaks may not be detected in fifteen (15) seconds. The meter samples forty (40) to fifty (50) flow measurements per minute, but only reports when polled.

15. Results are applied to observation intervals for development of rolling averages.

16. The system can see small leaks and have quick responses to large leaks.

17. Siemens can be a single supplier.

18. They can track batches and pigs.

19. Repeatability is more critical than accuracy.

20. Leak detection can be bi-directional.

21. Leak detection graphs were discussed.

22. The system can build in buffers to avoid alarms during packing and unpacking conditions to avoid false alarms.

23. They provide "thermo-modeling" to help understand what is going on in the pipeline.

24. Leak location is done by the difference in the time-of-flight of the rarefaction wave to measurement nodes; possibly up to a 150-meter resolution.

25. Siemens can provide turn-key solutions.

26. They can monitor the system from New York to develop historical behaviors for analysis.

27. Communication has many options.

28. Leak tests in an example included flowing conditions and static conditions on a 450-mile pipeline.

29. Data tables were discussed.

30. Flow meters were optimized to one and one-half percent (1.5%) relative to each other.

31. Leaks were detected while packing and unpacking.

Questions and Responses

The evaluator asked if they used conservation of energy, mass and momentum in the modeling algorithms.

> The presenters did not know, but considered their algorithm to be modeling the thermal profile.

The evaluator asked how they can detect a rarefaction wave to a meaningful resolution with a one (1)-minute scan rate.

> The presenter stated that they acquire data every tenth of a second and time stamped it for use after it is transmitted in the data update on a minute basis.

Evaluator Comments

The evaluator admits a long-standing suspicion about the fragility of clamp-on ultrasonic meter compared to the reliability of machined spool meters. However, the evaluator also admitted in recent years some companies have deployed clamp-on meters and have standardized on them because they have demonstrated a high degree of reliability. It is believed that methods of ensuring reliable coupling between transducers and the pipe have evolved to a point coupling reliability may be a lesser concern than in the past. In keeping with an interest in erring on the side of caution, the evaluator recommends consulting with the meter vendor regarding deployment methods suitable for the Alaskan climate prior to a commitment, including a program for field tests on pipes that would demonstrate tolerance of the usual sources of decoupling.

The Siemens leak detection system is presumed to be based on the system that was distributed with Controlotron meters before Siemens acquired Controlotron. In any case, the evaluator was pleased to hear the system attempts to estimate the effect of changes in linepack on leak detection performance. However, thermal issues are known to be problematic with other meter-based systems in Alaska where RTTM technology is not used.

The evaluator notes that the general term "model" means to "produce a representation or simulation of[3]" something and, with that broad definition, any effort to assess linepack throughout the line can fall under that terminology. However, it is generally accepted by many in the leak detection community that "modeling" a pipeline and data profiles involves dividing the line into short sections for the purpose of defining homogeneous segments whose characteristics can be applied to solve conservation of energy, mass and momentum equations accurately. In the case of the Siemens leak detection system, the nature of linepack analysis algorithms remains elusive. It is presumed that if their thermal modeling algorithms involved the most detailed solutions typical of RTTM technology, this capability would have been

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[3] http://www.merriam-webster.com/dictionary/model

prominently displayed in the slide presentation. Consequently, until further details confirm a sophisticated thermal modeling capability, this system should be deemed more suitable for short lines with limited thermal issues.

In Comment 22 above, the presenter indicated that buffers are provided in order to limit false alarms during packing or unpacking conditions. This statement suggests the use of persistence in distinguishing between a leak and a normal unpacking of the line; a method frequently used to accumulate imbalance data until it overwhelms uncertainty thresholds. The context of the discussion near that description may indicate a strong dependency on persistence, which suggests potentially significant uncertainty in the linepack estimate; thus potentially lengthening the time-to-detect compared to times offered by RTTM solutions. Until further details are acquired regarding the potential linepack estimation accuracy for potential projects, this solution would be most applicable where the temperature profile is substantially linear or where its shape can be accurately estimated and tracked by native algorithms.

8.2.7 Presentation 7 – Selecting a PLD for a crude Oil Transmission Pipeline with Temperature Variations as Product is Conveyed Downstream
(Morgan Henrie, Ph.D/PMP and Philip Carpenter – MH Consulting; Ed Nicholas – Trans Alaska Pipeline System)

Morgan Henrie PhD, PMP, Philip Carpenter, and Ed Nicholas prepared this presentation. The websites are http://mhcinc.net and http://www.alyeska-pipe.com, respectively. Dr. Henrie and Mr. Nicholas delivered the presentation at the conference. Presentation slides are available as Appendix F in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points included the following:

1. The discussion would be product neutral.

2. Questions to be answered included what thermal effects impact leak detection and what other uncertainties limit the sensitivity of a leak detection system.

3. A model of the effects of uncertainties would be presented.

4. Consideration of the thermal effects of temperature is important if the potential sensitivity of any particular system is to be determined.

5. Many other variables have uncertainties and the cumulative effects of all uncertainties must be considered. This presentation focuses on thermal effects.

6. API-1149 lists seven (7) parameters whose uncertainties may affect leak detection. An example of a batched multi-products line was given.

7. Two (2) field measurements (temperature and pressure) have a significant impact, with temperature having a greater impact on crude oil lines.

8. Effects of being above ground and below ground along the line create uncertainty in heat flow.

9. For crude oil of API-33, the coefficient of expansion is .0005 degrees F. A one degree (1°)-change would cause a 0.05% change in fluid volume. This can be significant for a large pipeline segment.

10. Examples of heat transfer included a reference to the evaluator's earlier example of fluid warmed in transit following an earlier warmer batch and the diurnal effects of the sun.

11. When temperature is important in leak detection is dependent on the operating environment and leak detection performance requirements. (See Section 4.1.1 for an explanation of the effect of temperature on linepack.)

12. Each pipeline is unique. This uniqueness needs to be understood when evaluating products for use on the pipeline.

13. Possible performance criteria for product evaluation include highest sensitivity, shortest detection times, lowest number of false alarms, or all these. There are tradeoffs and compromises.

14. Consider how thermal and non-thermal uncertainties affect leak detection performance.

15. The presenters described an equation representing the effect of temperatures on packing rate uncertainty as influenced by flow rate and resulting transit time. The result describes the expected leak detection sensitivity.

16. It is hard to get a handle on temperature and *there has been a lot of discussion about temperature over the years with little science behind it* (evaluator's interpretation of presenter's reference to "hand waving over the years").

17. Only measuring temperature at segment end-points or localized spots made it difficult to know the shape of the thermal profile.

18. Water flow around the pipe, wind, rain, solar influences, etc., affects the temperature along the line. On at least one (1) pipeline, diurnal effects at certain times of the year on the fluid volume appeared to be equal or greater than the one percent (1%) state mandated leak detection released volume requirement.

19. The larger the volume of the pipeline compare to its flow rate, the larger the volume changes due to temperature excursions are.

20. The packing rate uncertainty equation was repeated with a table showing minimum leak detection thresholds expected with thermal uncertainties of one-tenth, one-half, one and two degrees Fahrenheit (.1°, .5°, 1°, and 2° F) per hour. Three (3) examples of flow rates illustrated at some flow rates and some uncertainties showed that, under some conditions, it is impossible to meet the mandatory leak performance level in Alaska.

21. Uncertainty contributions include instrument type, location, and installation methods.

22. Leak detection tools have uncertainties in their algorithms, as well as snapshot measurement uncertainties. This can result in a multiplier of two (2) for the uncertainty.

23. Examples of the effects of temperature uncertainties on typical pipelines 25 miles and 40 miles long, and representative of North Slope pipelines, were described. Example pipelines were simplified with respect to elevations and other parameters. Absolute numbers are not as important as the nature of the temperature decay. The temperature delta across the pipeline increased with transit time. The 25-mile pipeline showed the effect of a longer transit time at

lower flow rates.   Leak detection thresholds are presented in a second table. For some pipelines and flow rates, compliance with mandated leak detection performance is not possible.

24. Major ideas were summarized.

Evaluator Comments

The evaluator did not have a question, but complemented the presenters on a clear and concise paper dealing with the subject. He added that, where temperature profiles are not known to be an issue in the South, some persons new to the pipeline industry think of temperature uncertainty as the uncertainty in the actual measurement rather than the uncertainty along the pipeline.

> The presenter added that, on TAPS, the temperature can vary significantly between the origin and destination up to one hundred degrees (100°) and described environmental reasons that cause the variation. It is a challenge for any leak detection system to deal with this problem.

The evaluator told of a system Dr. Jerry Modisette was involved with for which a lot of temperature uncertainty was caused by varying currents in a bay along with changing water temperatures. The real-time model-based system worked well, but had to tolerate temperature/fluid density uncertainty resulting from the effects of the bay water on the segment that necessarily included many miles of dry land based on instrument location. After numerous suggestions that a temperature transmitter be installed where the pipeline left the bay, and after its installation, the model was able to accurately and independently estimate the thermal profile in the bay segment of the line and the on-land segment; thus allowing much improved leak detection performance.

8.2.8   Session 2 Follow-Up

Questions and Responses

The evaluator asked for opinions regarding our focus on thermal issues heard in Session 2. Will this drive the industry to use other technology in the future?

> Michael Twomey explained that temperature has not been a problem with their ATMOS Pipe leak detection system on over four hundred (400) pipelines and has had good results in Alaska. There may be a pipeline for which temperature will be a problem, but they have not found it so far.

The evaluator recognized ATMOS Pipe's well-known success on numerous projects.

The moderator asked the audience about their work environments; Alaska, the lower forty-eight (48) states, international, and by climate.

> Hands were raised.

From the audience: A question was asked regarding whether there are any published leak detection times vs. leak rate plots.

> The evaluator explained that API-1149 provides an estimate of such performance, but that several parameters it uses are difficult to quantify. Temperature uncertainty is a problem because the overall temperature uncertainty is not known, considering the uncertain temperature profile along

the line. Transient models can deal with the temperature profile fairly well, as long as the stations are sufficiently close together that the fluid temperature does not approach environmental temperature well before the fluid reaches the downstream station, and the shape of the temperature profile cannot be predicted. Publishing a specification for that would be difficult because all pipelines are different and the same pipeline operated at different flow rates would be different, too.

Another person confirmed this opinion and said it is impossible to define generic detection time vs. leak rate relationships.

Someone else suggested installing several different leak detection systems.

From the audience: Another question pertained to claimed false alarm rates corresponding to shortest detection times.

The evaluator explained that most systems had algorithms to limit false alarms independent of leak detection sensitivity or detection times. Calculations determine a probable leak, but rules involving control actions and known causes of false alarms inhibit such alarms. ATMOS Pipe may be unique in the way it applies statistical methods to determine the probability of a leak and thereby limit false alarms. It is hard to tie a false alarm rate to detection time.

The evaluator added that sensitivity is limited by flow measurement accuracy. He explained that, over a twenty-four (24)-hour period, any effects of transients have been diluted as have linepack uncertainties. What would be left for analysis would be the accumulated twenty-four (24)-hour flow imbalance and a relatively small change in linepack since the observation began. However, changes in flow rates and such can disturb the quiescent state of the pipeline and add uncertainties to the measurements.

Michael Twomey (ATMOS) confirmed that flow measurements are critical and that manufacturer specifications are seldom met. Tuning may help, but one percent (1%) is a common practical limit.

From the audience: What leak detection systems are successful on aboveground pipelines in Alaska?

Daniel Vogt (Krohne) explained that their system is not in Alaska, but they have an over ground system in Siberia that has been successful.

The evaluator declined to answer because of limited knowledge about the history of leak detection success levels in Alaska.

Michael Twomey (ATMOS) explained that their system shortened detection times from fourteen (14) hours to fifty-two (52) minutes in one (1) leak test of one percent (1%) compared to the incumbent system. He did not mention the pipeline by name since he had not asked for permission to do so.

The evaluator pointed out that thermal issues have been worked on around the world. Alaska is unique because the thermal issues are more of an aggravation because of the wide ranging fluid injection temperatures and delivery temperatures, as well as ambient temperatures that can vary seasonally and even daily. The problems have largely been solved in some systems with sophisticated algorithms. Solutions are at hand.

From the audience: If flow meters are required, what are your flow meters of choice?

> The evaluator explained that a wide variety of meters are available and the best meters are desirable. He gave the example where they were asked to tell a customer what quality meters were required to meet a specific sensitivity and a one (1)-hour detection time on a 16-inch, 1½-mile long pipeline flowing ethane injected at either seventy degrees (70°) or one hundred twenty-five degrees (125°). He also explained that, at normal flow rates, almost any meter would suffice with their existing volume balance system because the fluid was exchanged in a half hour; thus allowing the development of a new quiescent state during the second half hour after the fluid exchange occurred. But, at lower flow rates, the exchange was not completed within an hour and the balance of net volumes either indicated a leak or masked any leak at the target level.

> The evaluator explained the problem of one (1) barrel of cold injected fluid pushing out one (1) barrel of warm fluid, thus indicating a shortage in terms of mass being delivered compared to that injected, or a leak. In the other case, a warm barrel pushing out a cold barrel of fluid would be an overage in terms of mass delivered compared to that injected and would tend to mask any leak that was present. The report was that no meter on the planet could solve that problem. A RTTM was needed to make a meter-based solution possible under those operating conditions because it could track the density profile and account for the varying linepack. Look at applications when choosing meters; but, generally speaking, more accurate meters provide better results under limits imposed by the algorithms used by the system.

From the audience: How do hydraulic models handle velocities down to one (1)-inch per second? And, how does this affect pipeline inventory assessment of skin temperature measurements as a way to measure fluid temperature?

> The evaluator asked Ed Nicholas (Trans Alaska Pipeline System) to respond. He explained that all uncertainties increase significantly at lower flow rates. The mathematics work fine, but uncertainties in the meaning of the data can adversely affect performance. (Portions of his explanation were unintelligible in the recording due to low volume due to the unavailability of a microphone close to him.)

> The evaluator explained that the issue with skin temperature monitoring is the quality of the insulation and its ability to shield the skin of the pipe from external environmental influences. He explained that, when not flowing in a turbulent mode, there may be some fluid temperature differences close to the outer wall compared to the fluid temperatures in the center of the pipe; thus creating measurement error. Using skin temperature measurements is a common thing to do.

> Dr. Henrie (MH Consulting) explained that the thermal gradient across the fluid in the pipe can be a significant issue with regard to increasing temperature uncertainty. The location on the pipe can be important when operating at low flow rates, especially if vapors form on the top of the pipe under slack conditions.

> The evaluator added that turbulent flow has to be relied on to ensure all the fluid is the same temperature.

From the audience: How accurate and precise are noise filters?

> The evaluator explained that averaging in the Programmable Logic Controller (PLC) offers an advantage of sampling many times per second. This can extend resolution as well since fractional

components of the average can be stored and reported. Some PLC modules have inherent capabilities to filter out 60 Hz noise. Filtering hydraulic noise would be more difficult. However, some filtering algorithms apply a "K" factor in a manner that the current measurement is combined with a previous value that has already been subjected to this algorithm. Filters create time skew in measurements so, if filtering is used, it should be applied to all measurements in order to maintain time relationships.

Ed Nicholas (Trans Alaska Pipeline System) added that filters help a great deal and must sample at twice the highest frequency actually wanted to see according to Nyquist criteria. He recommended filtering in hardware in the field where sampling can be frequent to eliminate high frequency noise and use the digital filters for low frequency noise. He clarified that you cannot filter noise using a lower frequency sample rate than the frequency of the noise.

From the audience: Some vendors use the client's Pressure/Temperature (P/T) transmitters and some use their own. When would you tell the client that their transmitters are not accurate enough for use in a leak detection system?

Daniel Vogt (Krohne) said they tend to use the client's transmitters and make recommendations if improvements are possible. This may include adding transmitters at other locations.

The evaluator explained that there are no particular standards. Most commercially available transmitters offer one-tenth percent accuracy. That is not where the issues lie. The effect of temperature on linepack and its assessment is the primary issue. The temperature measurement only measures the temperature at that one point where the temperature transmitter is located. It cannot tell anything about the entire temperature profile of the pipeline. With pressure, there is the same situation except it is much easier to construct an accurate pressure profile because there are fewer unknowns than in estimating the temperature profile. Most commercially available transmitters that would work well in their installation environment would be adequate.

Michael Twomey (ATMOS) added that their ATMOS Pipe system works fine with any pressure transmitter, but their ATMOS Wave system, which detects the rarefaction wave generated by a leak, needs a high quality transmitter. It appears that some transmitters are overly complex in that they digitize their measurement and process it; then convert it back to an analog signal for transmission to SCADA. This can result in difficulty recognizing small changes in pressure. It seems like the more electronics they have the noisier the transmitter is at the bottom end. Sometimes simpler is better.

The evaluator recommended working with the vendor to determine the best instrument options.

Dr. Henrie (MH Consulting) added that, with meter-based systems, absolute accuracy is not so important. In the case of rarefaction wave detection, you are trying to detect that one event, a rapidly occurring event that, if missed, is gone. This is a different criteria for instrument selection than in meter-based tools.

Michael Twomey added that many customers want to piggy-back multiple systems onto the same instruments. Dr. Henrie agreed, adding that in such cases the more stringent of instrument requirements should govern.

Another person added that their product dealt with pressure/volume measurements and certified tests based on certain equipment involved in hydrant leak detection systems. In one case, a client

had already deployed inferior transmitters that were replaced at the vendor's expense to ensure certified performance.

From the audience: What power sources exist to power detection systems, especially remote locations?

The evaluator explained that typically you will find a way to transfer the data to a less remote location where power is available in order to avoid burdening the remote sites with computing hardware.

Someone else explained that some meters are powered by thermal generators of some sort. These do not require much power.

The evaluator recommended working with the vendor to solve the problem.

From the audience to ATMOS: How long does it take your system to learn the pipeline's behavior?

Michael Twomey explained that around thirty (30) days are used for initial tuning if that is enough time to see all scenarios. Otherwise, tuning can be revisited when a new scenario is expected to occur. Tuning is ongoing at ATMOS when the system is operating relatively steady-state and lambdas are low.

From the audience to ATMOS: Are there any installations on multi-phase pipelines such as flow lines?

Michael Twomey explained it is installed on two (2) multi-phase pipelines in Russia. He stated "How good you measure is how good we will be". He is traveling to Brazil on a multi-phase project where they may spend as much as $500,000 per flow meter.

From the audience to Krohne and Telvent: Are there any installations on multi-phase pipelines, such as flow lines?

Kelly Doran (Telvent) indicated their system has been deployed on a number of flow lines. Daniel Vogt (Krohne) indicated they do not currently have any, but one is planned next year on the coast of Germany.

From the audience to ATMOS: Sequential Probability Ratio Test (SPRT) is based on increased measured flow imbalance. How do you distinguish flow offsets caused by leaks from other causes, such as different injected batch not accounted for or slack conditions?

Michael Twomey explained that an unmetered injection will be learned as a large normal flow difference. When the batch goes away, there may be a leak alarm. On slack line, they prefer a pressure sensor near the slack area in order to detect slack conditions to adjust thresholds. He gave an example where one line operated at five-tenths percent (0.5%) sensitivity except where it goes slack and sensitivity is reduced to five percent (5%).

From the audience to Krohne and Telvent: The gradient method for leak location works for flowing conditions. How well does it work for shut-in conditions?

Daniel Vogt (Krohne) explained that they have three (3) methods of locating leaks and the gradient method will not work during shut-in conditions. Detection of the rarefaction wave can work in shut-in conditions.

Kelly Doran (Telvent) agreed.

From the audience to ATMOS: Can you describe some of the crude oil and refined products pipelines that use ATMOS products in Alaska, including their characteristics?

Michael Twomey answered that he could, except that he had not asked for and been given permission to do so. But, ATMOS Pipe has been installed on seven (7) pipelines for two (2) years on the slope. It has recently been tested on two (2) refined product pipelines.

A follow-up question was: What kind of testing is usually done in Alaska?

Michael Twomey described annual tests, but did not have details.

From the audience: How many successful applications are there on aboveground pipelines at low flow rates?

The evaluator explained that his knowledge of history was limited but, in the lower forty-eight (48) states, there are successful installations. In the South, the influence of the sun can be mitigated with a RTTM and configuration to handle solar influences or with insulation. It is a common problem, but not one that cannot be solved.

From the audience: In terms of total percent of total installed cost, how much is spent on the cost of configuring and verifying the model?

The evaluator said from his experience on projects there is a small incremental cost to cover the configuration of the model. There is an effort by the pipeline operators to collect the required data about pipe characteristics. On some older pipeline networks, as-built data can be incomplete or wrong in the archives. Modern models often have graphical configuration tools that improve configuration efficiency.

The evaluator said there is a reputation regarding RTTM products that they require significant ongoing maintenance. He explained that in the early days a significant vendor of this technology sold numerous systems and appeared to stop working on these systems as their budgets ran out. That was largely because they diverted funds from one project to another and that some people went to jail over financial issues. What is true about RTTM systems is that they allow you to continuously strive for improved performance. However, once you are satisfied with performance, there is no need for further maintenance.

The evaluator further explained a situation where a company used a real-time model on a gathering system with three (3) wells in a highly transient operation. The operation was sold, people retired and, finally, the old DEC PDP-based RTTM system was replaced with the latest non-model based technology from the same vendor. People had forgotten it was a RTTM. It was only discovered the old system was based on an RTTM after we were asked to determine why the new system was perpetually in alarm and the old one worked fine. ATMOS replaced the upgraded system with ATMOS Pipe and it worked well. It seemed interesting that RTTM systems are reputed to require continuous maintenance and these people did so little maintenance they did not know they had a model. He declared the criticism that RTTM systems require significant maintenance to be unfounded.

Ed Nicholas (Trans Alaska Pipeline System) explained that the time is not spent configuring the model up front, but rather dealing with all the things that were unexpected, such as instrumentation issues. The RTTM is probably the first system that looks at the time-dependent relationship of measurements. An example was given where closing a valve to end a delivery isolates a temperature sensor for the flow stream. The time is spent on these issues more than the actual model configuration.

Kelly Doran (Telvent) explained that discussions regarding the actual placement of stations on the line can occur when modeled results reveal an anomaly in modeled behavior. In the example case, the location of the station was incorrect. Investigations of these issues can take time.

The moderator asked how often tuning should be done.

Someone indicated tuning is not necessary unless changing the piping.

The evaluator told the story of a client with a custom RTTM who asked its supplier to upgrade it, but he recommended a commercially available tool since they had matured quite a bit. The first behavior of the model upon startup was so close, the operator went to the as-built drawings to see if there might be a pipe characteristic that was misconfigured because the interface arrival was close, but not exact. Thermal tuning was needed because of the thermally transient environment.

The evaluator concurred with Mr. Nicholas regarding orphaned measurements and the effort to resolve instrumentation issues, and gave an example of an orphaned temperature transmitter.

From the audience: What is the sensitivity level that can be achieved without unacceptable false alarms on single and multi-phase pipelines?

Michael Twomey (ATMOS) stated that there is no single answer because all pipelines are going to have a different answer.

Ed Nicholas (Trans Alaska Pipeline System) added that it would be no better than the cumulative accuracy of the meters because a leak is simply unmetered flow from the pipeline. If you cannot meter flows accurately, then you cannot find the leak.

The evaluator concurred and added that the aggregate uncertainties in flow measurements are the limit. Any effort to limit false alarms near the limit will result in a decrease in sensitivity and/or extension of detection time.

From the audience: Convince me your solution can find an existing leak (a small one) without considering it part of the existing system or measurement noise. I do not get a warm and fuzzy feeling about this even though all of you have convinced me you can find future leaks. I do not want to find this kind of leak during normal maintenance.

Michael Twomey (ATMOS) said existing leaks are a challenge that can be met with a shut-in pressure test. He added that, on tests with ATMOS Pipe and Wave concurrently, they found evidence of an existing leak in the acoustic signature emitted at the leak location. But, a shut-in leak test is all that worked on that small leak with ATMOS Pipe alone.

From the audience to ATMOS: Given the ATMOS system learns the pipeline network, what is the impact if part of the network is changed?

It depends on what is changing. Changing a pump or temperature transmitter will not affect the system. If changing a meter, you may need to retune the system. A longer tuning process can be done over time, but a fast retune can be forced in a few minutes.   Adding a delivery or injection point can take a few hours to configure.

From the audience for Krohne: How does the TCP/IP interface handle data quality, such as bad polls?

Daniel Vogt explained that they can use any protocol in the industry and TCP/IP does not have to be used. He added that data coming back will be analyzed for communication statistics and other data quality conditions.

The evaluator stated the use of TCP/IP for data transmission should not preclude the use of the application layer protocol analysis tools that would be used if direct serial communications were employed without TCP/IP. Errors, such as no-replies, would still apply.

From the audience to Telvent: With a model update of four (4) times per second, how fast is the I/O updated, and can other SCADA systems be interfaced with SimSuite?

Kelly Doran explained that SimSuite can be interfaced with other systems. The calculations can be done four (4) times per second, but field data updates are often every five (5) seconds.

From the audience: How do pigging operations affect leak detection?

Michael Twomey (ATMOS) said it is part of normal operations so tuning has to deal with it.

The evaluator explained that a few false alarms should be expected because pig travel through the line is not always uniform. It can stick occasionally and pressure drops in front of it, rises behind it, and it starts moving again. Pressures are reflected at the endpoints. It is important to note whether alarms are persistent as an indicator that this may be occurring.

Ed Nicholas (Trans Alaska Pipeline System) explained that pigging affects flows, too. Hydraulic gradients change between pig runs as wax builds up in the line. Wax pickup can affect pig motion and instrumentation along the pipeline.

Another voice indicated pig passing can be detected, but it will affect flow measurement until the pig clears the segment.

Dr. Morgan Henrie (MH Consulting) added that, during pig passage, flow may go to zero (0) in ultrasonic meters and result in a transient loss of flow indication. The system needs to deal with this. Slippage and jerky movements can be significant.

Ed Nicholas pointed out that once a pig entered relief piping after the TAPS pipeline had been shut down due to a call reporting a leak. This caused some serious operational difficulties.

8.3   Session 3: Vapor Detection and Liquid Sensing PLD and Related Practices

Session 3 had a primary focus on the detection of fugitive product by various means instead of determining the presence of a leak by hydraulic behavior. Several commercial products based on various technologies are becoming common in the pipeline community.   Base technologies include vapor

detection, liquid hydrocarbon detection, and detection of temperature anomalies indicative of released fluid.

In some cases where the presentation was purely about products that may be incorporated in leak detection systems provided by others and the product was described in detail on the manufacturer's website, the review of the presentation was abbreviated in favor of Web investigation or an attached slide presentation. In other cases where the presentation covered a comprehensive leak detection strategy, the review will be complete.

8.3.1   Presentation 1 – LEOS®
Dr. Walter Knoblach – AREVA NP GmbH, Germany, and Peter Bryce, PE, - Brycetech Consulting, Inc., Vancouver, Canada

Dr. Walter Knoblach and Peter Bryce prepared this presentation. Their websites are http://www.areva-diagnostics.de/en and http://www.bryteches.com, respectively. Dr. Knoblach presented the paper. Presentation slides are available as Appendix G in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points included the following:

1. The LEOS® System was installed on the 6-mile long Northstar Pipeline in Prudhoe Bay, Alaska in year 2000, then on the OT-21 flow line in year 2008.

2. The good news is the technology is much more sensitive than meter-based systems. The bad news is that extra hardware is required.

3. Detection of small leaks is important because of the potential for a large accumulated volume from undetected weepers.

4. Corrosion holes can be small, and grow until it is detected by typical systems. A graph illustrated the growing volume. LEOS® can detect the leak in very early stages.

5. It works underground and underwater.

6. Response times are in hours, but sensitivity is very high compared to other systems. Sensitivity is not dependent on any hydraulic condition in the pipeline.

7. It is not competitive with meter-based solutions, but is complementary instead.

8. A sensor tube is installed with the pipeline. The tube is permeable to hydrocarbon vapors, but not water. Any vapors from released fluid migrate into the tube. At some point in time, air is drawn through the tube at a constant rate and the air is examined for hydrocarbon vapors. A tracer gas is injected in the far end of the tube at the beginning of the test to mark the end of the air column. The position of any hydrocarbon vapor in the air column reflects the location of the leak along the pipeline.

9. Any leak results in a high concentration of hydrocarbon vapors.

10. Illustrations of sensor tube types were provided.

11. Pictures of hardware subsystems were provided and explained.

12. Operation can be once per day, but in Prudhoe Bay they test every six (6) hours.

13. A case study of the BPXA Northstar Pipeline (2000) was provided and discussed. The required detectible leak rate was huge compared to their actual capabilities. Naturally occurring gasses in the soil needed to be ignored. Special environmental concerns, such as moisture and icing, needed to be handled.

14. Improvements in gas analysis technology using infrared-based multichannel gas analyzers have been made.

15. Very low maintenance system is required.

16. There are no false alarms.

17. A case study for BPXA OT-21 flow line was presented. Special sensor tube technology was developed for the application.

18. Self-diagnosis of ice forming and other issues are built-in.

19. The system is based on proven thirty-five (35)-year old technology, with 270 kilometers of installed product.

20. It is proven in Alaskan environments.

21. Leak rates of one (1) liter per hour have been detected.

Questions and Responses

The evaluator asked how long it takes to draw the sample through the tube on a per mile basis.

> It takes about five (5) hours to draw the complete sample on the 6-mile long Northstar Pipeline. On the OT-21 line, they completed the sample of 3 miles in one (1) hour.

The evaluator asked if growing ice blockage can be detected by monitoring the suction pressure.

> Measuring mean suction pressure and flow velocity are part of the self-diagnostic capability.

The evaluator asked if the system can be interfaced to SCADA systems.

> The system has dry contact interfaces at the moment.

The evaluator asked if the control system can initiate a test on a periodic basis.

> The system is configured to run periodically, but independently.

Evaluator Comments

The LEOS® system has been used in the pipeline industry for a very long time, though not usually on long-haul transmission lines due to its potentially limited range due to diffusion of the hydrocarbon vapor sample and long distances between stations. It's limitation of being slow to acquire a sample prevent its use as a primary leak detection tool looking for leaks of any size. However, when deployed with a meter-based tool, this system can extend sensitivity to the smallest of weepers. It is a good candidate for a role of a secondary leak detection method in Alaska and, if appropriate, on a case-by-case basis as a primary method where metered flow is not an option and the cycle time of the tests are deemed tolerable.

8.3.2   Presentation 2 – FLIR GF-300 Series Cameras
David Shahon – FLIR Systems

David Shahon gave this presentation. The website is http://www.flir.com. The presentation dealt with optical investigation of leak detection and location using thermal imaging cameras. Since the focus of the presentation was on products somewhat removed from full length pipeline leak detection, but was of great value in a stand-alone operation where investigations were locally focused, this summary will be abbreviated in favor of product reviews using the company website. Presentation slides are available as Appendix H in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points include:

1. Origins of the technology were military applications.

2. Product evolution was funded by military projects.

3. Handheld devices provide optical gas imaging. A video was presented.

4. An example showed an image of a leak where other sensors were placed to provide leak alarms if a leak occurred.

5. They are useful in locating leaks found by other means.

6. Cameras are based on infrared technology.

7. Focusing on narrow wavelength bands increases signal-to-noise ratios.

8. Images were presented illustrating results.

9. Detection limits were listed for gases of interest. The cameras do not distinguish between gases.

10. Detection of methane ranged from three (3) to twelve (12) meters, depending on the lens used.

11. A good application would be checking valve and fitting status.

12. An example of a flare purging gas without burning it was provided.

13. Cameras are designed for rugged use.

14. Cameras can make still images or video clips.

15. They can be calibrated for temperature measurement use.

16. Another video of a gas cloud was presented.

Questions and Responses

The evaluator asked if they make their own lenses and if lens coatings have an effect on the signals.

> They make their own lenses and added that infrared signals will not pass through glass. He showed the opaque window in an image of a helicopter as an example.

The evaluator asked if background gasses in a propane or butane bottling operation would make it difficult to scan for other sources.

> The instrument would probably see the background gasses if they are in sufficient concentration. The leak sources most likely would be seen if the background concentration is low.

Evaluator Comments

These cameras are a tool best used to determine if fugitive vapors exist in a particular area. The cameras can be mounted on fixed stands in order to monitor gas presence in stations or used in a hand-held mode. They would be applicable for inspecting a pipeline ROW for fugitive natural gas emissions too small to see with the naked eye.

8.3.3   Presentation 3 – TraceTek 5000 and TT-FFS
Ken McCoy – TraceTek Leak Detection Products/Tyco Thermal Controls

Ken McCoy gave this presentation. The websites for TraceTek and Tyco are http://www.tracetek.com and http://www.tycothermal.com, respectively.   Presentation slides are available as Appendix I in

Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011.   Significant points included:

1. Raychem, which developed the hydrocarbon sensing cable described in this presentation, is probably a familiar name on the North Slope because of its conductive polymer heater technology. Raychem was bought by Tyco in 1999.

2. Traditional leak detection is fast with large leaks. Periodic testing is only valid at the time of the last test.

3. The primary criteria for leak sensitivity should be focused on volume released rather than percent of flow.

4. Leaks just under the detectible level can result in large volumes over time.

5. A typical performance curve for meter-based systems was presented.

6. Any undetected leak continually contributes to released volume until its discovery.

7. Their hydrocarbon sensing cable can detect a few milliliters of fluid making contact with the cable.

8. The cable is not fast enough to limit spilled volume from large ruptures, but it can limit accumulated volume from small leaks.

9. The combination of the meter-based tool and the hydrocarbon sensing cable complementing each other makes for a good hybrid system.

10. The cable uses conductive polymer technology. The electrodes carry a low DC voltage signal with no normal current path between them. The cable material acts like a hydrocarbon sponge that swells upon contact with liquid hydrocarbons, thus forcing the electrodes together at the contamination site.

11. The cable excludes water.

12. An illustration of the system was presented.

13. The voltage drop across the shorted cable gives the leak location. Resistance of the cable is nominally four (4) Ohms per foot. Accuracy in leak location is approximately 3 feet per 5,000 feet of length.

14. For longer applications, multiple circuits are cascaded.

15. Three (3) versions of the cable were illustrated. The first and oldest is used indoors and in double-wall piping applications. The second type is for underground applications with its higher breaking strength outer braid. The third type is used on above ground applications where degradation due to sunlight and other environmental strains must be avoided.

16. Their second hydrocarbon sensing technology has a lower carbon loading with a thin silicon and graphite reactive layer sprayed on a circuit board. Resistance goes up quickly by a factor of one hundred (100) when it is contaminated. This makes a leak/no leak assessment easy.

17. Reaction time varies between seconds to one-half minute (30 seconds), depending on the fluid type. The name FFS represents Fast Fuel Sensor.

18. The difference between this and the cable is that it is a point sensor so the leaked fluid must be directed to the probe. It is best for containment areas.

19. This can be deployed standalone with alarms or with dry contacts. It can also provide a 4-20 ma current loop indicating leak/no leak conditions, as well as sensor conditions.

20. Emerson and Tyco partnered on a project in Alaska and have approval in hazardous areas. Up to one hundred (100) sensors can be deployed and monitored by a gateway.

21. Interfaces with SCADA are an option.

22. On pipelines, the Sensor Interface Module can support one thousand five hundred (1,500) meters of cable with a resolution of one (1) meter. These can be cascaded by network. The longest installation so far is about 35 kilometers in length supplying jet fuel to Tokyo's Narita Airport.

23. Modules can be integrated with SCADA using the Modbus™ protocol or with TraceTek's native alarm panel. An example was provided supporting about two hundred (200) channels with alarm indicators.

24. The cable is not applicable underwater because currents can carry released hydrocarbons away from the sensor.

25. Underwater double-wall pipe applications are not done because the cable must be pulled into the interstitial area between the pipes. Above ground installations require access for pulling around every two hundred fifty (250) meters.

26. The response time can be slow if the environment is cold (cold cable) and the oil is cold. However, the response time is good with hot oil on a cold cable.

27. Retrofit on an existing line is expensive due to the careful excavation required for cable installation. The best time for installation with underground piping is as the pipe is buried. For aboveground applications, the cable can be installed any time.

28. TraceTek 5000 is fast at the oil temperatures in the example pipelines.

29. It is also fast with refined products. C6 to C10 range molecules migrate quickly. Longer chain molecules migrate more slowly.

30. Applications include hard to get at locations, under tanks, around valves, etc.

31. Pictures were shown of a slotted PVC conduit through which a pull rope was used to pull the cable. An example of the Madrid Airport installation was shown.

32. Pictures of pull boxes were shown.

33. Pictures of tank bottom monitoring installations were shown. Grids of cables under tanks can ensure contamination and detection in specified times for two-tenths (0.2) gallons per hour mandated by regulation.

34. Valve boxes or buried valves can be monitored. Driving the ROW and looking for a flashing light can reveal a leak in the valve box.

35. Above ground piping can be monitored in terminals.

36. Casings and road crossings are good applications.

37. A picture of a double containment application in an arctic setting in Finland was presented.

38. Tank overfill is a good application for the FFS tool. An example of FFS between containment berms was shown.

39. The system is viewed as complementary to meter-based tools.

Questions and Responses

The evaluator asked if the point sensor (FFS) had ever been deployed in waterways where currents and prevailing breezes would drive any oil sheen to the sensor.

> Ken McCoy indicated that TOTAL is doing that, using tethered floating sensors that can detect very small concentrations of oil.

> The evaluator commented that such a sensor might be inappropriate for the Port of Houston, but in pristine Alaskan rivers it might find a home.

The evaluator asked if TraceTek/Tyco considered the nature of the trench fill, surrounding soil, and potential collection of rainwater when selecting the position of the cable relative to the pipe's circumference.

> Mr. McCoy indicated that they do. In a low groundwater environment, they place the cable at the same level as the bottom of the pipe. In a high groundwater situation, they place the cable at the 12:00 position with a sheet of polyethylene over it to make an oil trap with the cable acting as the ridge pole of a tent. Where groundwater varies by season, some customers use two (2) cables.

The evaluator asked if they had any leak indications on the Longhorn project.

> Mr. McCoy said they had indications of hydrocarbons that were found to be pre-existing contamination and/or washed in from other sources. The line is extra heavy wall in the area and only seven (7) years old.

The evaluator commented that these are not false alarms [from the standpoint of a technology failure].

> Mr. McCoy replied that they were considered false by the pipeline company because they had to shut the line down and investigate the validity of the indication before restarting the line.

Evaluator Comments

The TraceTek 5000 leak detection system is very suitable for detecting liquid hydrocarbons in localized or medium length applications. As described in the presentation, the only likely false alarms would be legitimate detection of background contamination. This might be problematic for retrofit in older facilities where discarded motor oil was regularly used to control weed growth along fences (an example). An early application of the TraceTek 500 product involved finding a way to extend its range to several miles in length. Since then, the product family has evolved such that support for extended distances is a standard feature.   The 250-meter distance between pull boxes is a bit short when considering the comment about manhole covers and the implied structures usually involved where full body access is required. However, such periodic access points facilitate less costly replacement of cable segments after pipe repairs and cleanup, and the manhole covers may simply cover a small vault just below the surface where appropriate cable connections can be made and physically protected from abuse. With the tiny volume of contamination required to cause an indication, this system is capable of providing a leak indication based on a zero (0)-tolerance detection level provided leeway is given for fluid migration from the leak to the cable.

8.3.4   Presentation 4 – GF-600 Cameras
David Shahon – FLIR Systems

David Shahon gave this presentation. The website is http://www.flir.com. The presentation dealt with optical investigation of leak detection and location using thermal imaging cameras. Since the focus of the presentation is on products somewhat removed from full length pipeline leak detection, but is of great value in a stand-alone operation where investigations are locally focused, this summary will be abbreviated in favor of product reviews using the company website. Presentation slides are available as Appendix J in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points included:

1. They have two (2) technologies with the same basis. The previous presentation (Section 8.3.2) dealt primarily with vapor detection. This presentation dealt with the P-600 camera used for temperature measurement.

2. A flying "Otter" is configured with a FLIR thermal imaging system for right-of-way patrols.

3. The P-6xx has several models and configurations.

4. One has GPS recording on each image.

5. Damaged insulation can be detected.

6. Resolution is up to a one (1) megapixel image.

7. Cameras are rugged and can handle the Alaskan environment.

8. Both Infrared (IR) and visible light images can be taken and be overlaid.

9. It is a long-wave camera; far away from visible light. Reflections are eliminated at that wavelength.

10. A video was shown to illustrate the development and operation of the camera in an application designed to test its ability to detect oil on seas.

11. FLIR cameras were used in the recent Gulf of Mexico oil spill to see oil not easily seen using visible light under some conditions.

12. An example of images was presented.

13. An example of observing traveling bears was presented.

14. Heat patterns from pooled oil is a good application. Monitoring the ROW with their cameras identifies anomalies.

15. 24-7 fixed mounts are an option.

16. Options for hazardous environments exist.

17. Temperature thresholds can sense flare status.

18. Images can be e-mailed directly.

19. Wet insulation can be detected.

20. IR does not work well on shiny metals when the sun's heat is present to be reflected.

21. Wind adversely affects the creation of the thermal signature.

22. This is a good tool for preventive maintenance activities where heat can indicate the need for attention.

23. Sludge levels in tanks can be detected.

Questions and Responses

The evaluator asked if various wavelengths had any difference with respect to monitoring crude oil.

> David Shahon explained that there is a small difference, but not enough to affect image creation. Mid-wave cameras are a lot more expensive than long-wave cameras.

Evaluator Comments

This camera technology is focused on detecting liquid hydrocarbons by thermal characteristics that may be in the form of radiant heat or thermal absorption. It is expected that observations will be local except in the case of traveling systems configured for ROW monitoring. It is not expected that fugitive oil will be detected when covered with a blanket of ice or snow. However, ongoing leaks may provide sufficient heat as to create a localized spot where a thermal signature may be seen as different from surrounding areas even though visible differences are not yet significant. The method is especially useful for facility monitoring or ROW examination in conjunction with a meter-based system.

8.3.5   Presentation 5 – PAL-AT
Art Geisler – PermAlert ESP, a Division of PermaPipe, Inc.

Art Geisler gave this presentation. The website is http://www.permalert.com. Presentation slides are available as Appendix K in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011.   Significant points included:

1. This system is not a good choice on contaminated sites unless they are cleaned up. It cannot tell the difference between old and new oil.

2. Worldwide offices and manufacturing plants were listed.

3. Technology involves Time Domain Reflectometry (TDR) which is similar to radar and sonar.

4. The technology was adapted from old cable analysis tools.

5. They have been on the market since 1988.

6. Examples of cable signatures were presented.

7. In effect, they are looking at the cable in increments, though under normal conditions it is seen from end to end. Resolution is around 5 feet.

8. They can see the original small leak, as well as a growing leak when more cable is contaminated.

9. The panel processes data and provides a break alarm if the cable is broken. Current software stops monitoring when a leak is detected. New software will allow monitoring of the cable between the pulse source and the leak site.

10. Examples of a shorted cable were provided.

11. Five (5) different panels exist, the most common of which drives up to 7,500 feet of cable. It can cover eight (8) cables and up to 15,000 feet of pipe (presumably with the panel in the middle).

12. Communications are provided by RS-232 and 485 ports and Ethernet connections. The Modbus™ protocol is supported.

13. Proprietary software allows the user to monitor the system directly.

14. There are three (3) kinds of sensor cables; two (2) of which were discussed in the presentation. The AGW Gold is applicable in Alaska. It is a quick-drying cable that will see any liquid. It is rated to four hundred degrees Fahrenheit (400°F). The second cable blocks water to 20 feet of depth. Crude oil will penetrate and cause an alarm. It will not evaporate so the section of affected cable must be replaced when it is contaminated.

15. They are EPA-tested down to two-tenths (0.2) gallons per hour.

16. Wet cable startup identifies affected locations on startup (presumably provided they are not contaminated to the degree that one affected area prevents downstream monitoring).

17. Cable breaks and shorts can be detected.

Questions and Responses

The evaluator asked what the leak location resolution would be.

> Art Geisler explained the resolution up to 5,000 feet would be 5 feet and, at 7,500 feet, it would be 15 feet.

The evaluator asked if there is a particular point on the sinusoidal waveform that would be indicative of the leak location.

> Art Geisler indicated it would be the leading edge.

Evaluator Comments

This method would be suitable for deployment over high consequence areas where cable characteristics match the environment in which it is deployed. As with other cable-based sensors, a plan to ensure a leak contaminates the cable must be developed and executed. Close cooperation with the vendor to engineer an appropriate deployment plan is recommended. Particular questions to address would be wet cable operation (noting the wet cable startup comment), the effect of ice formation in or around the cable, and splicing methods in the event a leak is detected and repairs are needed. Potential users should request a proposal based on a complete description of the pipeline, its environment characteristics, and performance goals. The proposal should describe performance limitations and their causes, as well as a deployment strategy that addresses regional and seasonal issues that may dictate particular installation methods.

8.3.6 Session 3 Follow-up

Questions and Responses

From the audience to the moderator: Will the presentation slides be available to the audience?

> Julie indicated that they were not intended to be and directed people to the individual presenters to inquire about copies of their presentations. (Because summaries of some presentations would be much more meaningful with visual content from the presenters' slides, current plans are to ask presenters for permission to publish their slides along with this report for further reference. Where company policies or other restrictions prevent public distribution of the presentations, they will not be available except possibly by individual request directed to the presenter. However, where permission to publish the presentation is granted, slide presentations will either accompany this report as appendices or be available on the website where this report resides.]

From the audience pertaining to LEOS® and cable technologies: When water (groundwater or rain) comes in contact with the cable, does it affect the ability to detect leaks?

> Dr. Knoblach (AREVA) responded for LEOS® and said, if any hydrocarbon is dissolved in water, its vapors will still migrate into the tube through the diffusion membrane which blocks the water only. It is slower because the water is another barrier to be overcome by migrating vapors (presumably because the hydrocarbon concentration on the membrane surface is diluted).

Ken McCoy (TraceTek) responded that they have run a number of tests on groundwater and found that they cannot get enough concentration of dissolved hydrocarbons to activate the cable but, in dirty environments, rising water can bring undissolved background contamination, or actual released fluid below the level of the cable to the cable in sufficient quantities to activate it. In clean conditions, where the trench is full of water, any oil leaked will rise and avoid a low cable. He mentioned cables above and at the bottom of the trench. He mentioned a project where a cable was located under a tent above the pipe specifically to solve this problem.

Art Geisler (PermAlert) responded that over time cumulative exposure to hydrocarbons mixed with water will result in an alarm. If oil floats away from the cable, it will not be seen. Specifically engineered solutions involving floating sensors looking for oil sheen are common.

Dr. Knoblach added that early tests of their Northstar system involved starting with a tube filled with water to determine if there were any (presumably long-lasting) effects of water incursion affecting performance.

From the audience to AREVA: The V-channel on the aboveground installation in the example did not appear to be continuous. Will product be detected where the V-channel is not installed? How do you determine where to install it? Is there an increased potential for corrosion where the moisture cloth lies in the V-channel?

Dr. Knoblach explained the V-channel in the example was not continuous. He did not know why it had gaps in that configuration. In some cases they used armored arrangements and would make other technical decisions for special circumstances.

He added that the 6:00 position is common for above ground systems because, even with the prevailing winds, oil will be captured in the V-channel and be directed to the tube.

From the audience to PermAlert: Do you also make point-based sensors?

Art Geisler explained that they do make such a sensor. They can use anything that has a high resistance change, including float switches. One product supports up to sixty-four (64) channels.

From the audience to FLIR: Can cameras see oil when the oil and snow are at the same temperature?

The question was asked before, but David Shahon (FLIR) did not have a clear answer. There is a difference in emissivity between oil and snow, but the effect on distinguishing oil from snow is not known. It is possible that oil on top of snow may be seen, but it has not been tested.

From the audience to FLIR: Can the gas sensitive FLIR detect vapors emitted from the cold crude?

David Shahon explained that the problem is that vapors are emitted less in lower temperatures, but they can be seen where they exist. At 50°, 60°, and 70° below, there is not much vapor leaving the liquid.

From the audience to TraceTek: What are the limitations of the sensing cable for cased crossings in arctic conditions? Are there examples of its use on the North Slope?

Ken McCoy explained the casing is a nice environment for the sensor to operate in because the temperature is reputed to be rather warm, a few degrees above freezing. On a cold day, fast

sensors at each end of the casing might take ten (10) seconds to react instead of five (5) seconds. Cable reaction will be a lot slower. The worst case would be a very cold cable (-20 to -40 degrees) contaminated by very cold oil, which might take days to react. The conditions in a casing would be much better and would probably require an hour or two to react.

From the audience to everyone: Would your tool work with cased piping below grade in culverts or utilidors where the pipe is not in contact with the soil?

> Someone described the installation of a cable with this in mind. Another indicated appreciation of utilidors. Being able to follow up a leak alarm by examining the pipe is a good thing.

> Dr. Knoblach indicated they have done this under rivers and such with success.

From the audience to AREVA: What is the longest deployment length of your product?

> Right now it is 18 kilometers, over 10 miles. Tests indicate they can work up to 25 kilometers with some products. A potential issue would be the diffusion and attenuation of the vapor concentration during transit.

> Ken McCoy indicated an old TraceTek site is on a Marine Corps base. The cable will off-gas lighter hydrocarbons and may reset itself. But, they tell customers to expect the cable to be a one-shot device requiring replacement of affected segments.

> Art Geisler said they have a 6-mile long PermAlert cable at one (1) site in Washington State. It is also a one-shot device, but may reset itself.

From the audience to TraceTek: Do you have to replace the cable after it is activated?

> Ken McCoy said yes, though it is possible to remove the cable and heat it in a vacuum oven before re-installing it. But, it is cheaper and more reliable to replace the affected segments between access points. Fast- acting probes are multi-use and can be reset by cleaning with solvents. End-to-end tests are regularly done by dipping probes in lighter fluid, then cleaning and re-installing them.

From the audience to FLIR: Do you need to make an on-site adjustment for different gases?

> David Shahon responded that there are no adjustments needed for different gases.

> Dr. Knoblach added that the LEOS® system does not require special adjustments for different gases. Vapors will dissipate after a while so the tube can be re-used. However, after a real leak, replacing a few meters of the tube during pipe repairs is a small cost. There may be some degradation of the tube resulting from long-term exposure to some chemicals (not hydrocarbons) if cleanup is not performed in a reasonable time.

From the audience to AREVA: For a pipeline installation, would you prefer to install your tube inside the metal jacket that protects the insulation or outside the insulation? Would it be more effective inside or outside the jacket?

> Dr. Knoblach explained they consider the manufacturing process for the pipe covers and welding processes that would be affected by the presence of the tube, or where rotating the pipe for best fit

during welding would be a problem for tube placement. Being too close to the welding zone during welding is risky, too. The tube is usually installed after pipeline welding is finished.

Ken McCoy added that deployment of an oil sensing cable in a perforated jacket between the pipe and outer cover can be a problem due to clogged holes when foam is injected after installation. A special process in Finland involved double containment pipe allowed foaming prior to pulling a cutting tool that created a perforated channel in the foam.

Another person added pre-insulated (factory installed) piping requires their sensing cable to be installed outside the pipe but, if insulation is added in the field, the cable can be pre-installed.

From the audience to TraceTek: Will your system work for methanol lines?

Ken McCoy explained that it would, but they have a different cable for that application. The other cable has a different blend of polymers that is more reactive to solvents. It is more commonly sold for use in plant environments.

Art Geisler explained that PermAlert has other cables for a number of fluids, including methanol. They also have cables for chemicals that would be considered solvents.

Dr. Knoblach said LEOS® is used for detection of methanol.

From the audience to FLIR: How long after a leak can a leak be detected thermally?

David Shahon indicated if everything is at the same temperature, there would be no thermal difference In the case of a water environment, the difference in reflective or emissive properties between oil and water would be sensed instead of temperature.

From the audience to all: What is the major deciding factor for installation of an external leak detection product on a crude oil pipeline?

Art Geisler indicated it would be where there is the most risk or in plants where most leaks occur. Critical areas with most societal visibility would be good candidates.

Ken McCoy agreed and added where regulatory influences exist or in particularly sensitive areas. SCADA packages have a very high initial cost regardless of the length of pipe. Their systems are low cost for short transfer lines. The sweet spot is between 100 meters and 4 or 5 kilometers.   In addition to HCAs, they have a good place on transfer lines, especially for very small leaks.

David Shahon added the FLIR cameras are useful as an enhancement to a maintenance program where inspection of plant equipment is needed to define needed maintenance. Application of their cameras was repeated.

Dr. Knoblach described an installation from the Slovak Republic to the east to Crimea where LEOS® was installed. There was a renovation project where LEOS® was added where watershed areas existed.

The evaluator expressed an opinion that these solutions would extend sensitivities and shorten detection times. He asked for comments regarding vendors' experiences working with regulatory authorities to gain acceptance of their products as additions to pipeline integrity management programs.

Ken McCoy said they decided not to go down that road too, far. The context appeared to be a worry about influencing regulators in dictating solutions.

The evaluator explained that the question was not intended to focus on dictating acceptance of any product, but on helping the pipeline company present the solution to regulators with the pipeline companies.

Ken McCoy explained that they had not done a great job there, but could have done better. They are getting better.

Someone said that they do not step into the political minefield. Certain states have a greater interest in regulating technology; Florida is an example. They support the oil companies if asked to do so, but they do not lobby on their own.

David Shahon explained that their technology is new so they have had to work with regulators to explain what they can see and help develop test procedures and regulations to allow the use of their technology where it fits. The EPA is one of their largest customers because of their inspection capabilities.

Dr. Knoblach said the regulators were already involved with the oil companies before LEOS® was considered. After the project, tests may be witnessed by regulators. In Germany, a 70-kilometer pipeline was constructed, but never licensed. AREVA had to make an effort to stay out of a vigorous battle between the public, pipeline company, and regulators. They provided technical information to their customer in support of lawsuits, but avoided taking a stronger role.

From the audience to all: Do you have any recommended changes for the State of Alaska to consider regarding leak detection?

Someone explained that three (3) years ago after an incident, he discovered the requirement was one percent (1%) of a day's flow. Depending on the size of the line and flow, this can be very small or thousands of barrels. Perhaps the regulations should reflect absolute maximum quantity of released fluid.

Someone else agreed and mentioned gas station limits of two-tenths (0.2) of a gallon per hour or one hundred fifty (150) gallons maximum spill. Everything in regulations is risk vs. reward.

David Shahon added it would be helpful to describe what has to be detected better.

Dr. Knoblach agreed and added that it would not be helpful to extend the requirement for meter-based systems down to one-half percent (.5%) or two-tenths percent (.2%). Instead, it has been shown that a second solution is required for small leaks.

The evaluator agreed with Ken McCoy and commented that extending performance can have many solutions and said trying to extend meter-based solutions has limitations due to measurement accuracy limits and uncertainties. He added that periodic static pressure tests can confirm pipeline integrity of the entire line. Even short rudimentary checks can confirm pipeline integrity. He added that extending performance under flowing conditions is needed because the pipeline operates most hours of the day under flowing conditions. Establishment of regulatory standards based on HCA characteristics, such as close proximity of waterways and potential of

fluid migration, is needed. The idea is to have one performance metric for the whole pipeline and others for local HCA areas.

From the audience to all: Only a few of all the vendors appear to meet an accounting-based method required by ADEC for a leak detection system. While the tools appear quite capable of detecting leaks, they cannot be used as a sole solution. Are there plans to develop an accounting-based system or to partner with a traditional accounting-based system to be applicable in the State of Alaska?

Someone indicated that the oil companies already should be performing oil accounting, and these systems are just another tool to be used to detect leaks.

Someone else questioned the term "accounting-based." The systems discussed today are much more sensitive than meter-based systems that could measure large lost volumes. Some companies do periodic inventory reconciliation. He gave an example of a company whose reconciliation could be off by a million barrels. They hoped the next reconciliation would include the missing fluid. That was the only leak detection program they had. The industry has not expected this type of leak detection tool to account for lost volumes.

Dr. Knoblach explained that they are collectively a basket of tools that each could serve as a secondary solution. He added that, because each would have different strengths and applications, it did not make sense to partner with a company. Instead, it is better to partner on a project basis with the pipeline company deciding which solutions apply.

From the audience to all: Recognizing all pipelines and conditions are different, and that life expectancy of components vary, what would be the generic cost level?

Ken McCoy said instrumentation costs are high and the more cable that is required, the more the system will cost. A good rule of thumb is $50,000 per kilometer.

Art Geisler said their costs were similar.

David Shahon said their cameras start at $30,000. Warranties are ten (10) years on the sensors. Helicopter-mounted cameras are around $150,000.

Dr. Knoblach indicated they are all in the same range, but it depends on the application. The total cost of ownership, including installation and maintenance, should be considered.

8.4   Session 4: Fiber Optics PLD and Related Practices

It was not very long ago when there was a great deal of information available about the potential of fiber optic technology in pipeline integrity monitoring applications. However, during the infancy of the technology, finding commercial products that were capable of exciting the fiber in some manner, interpreting any results, and generating useful information was a challenge. Those days are over now that commercial products exist that can collect data that can be easily interpreted and associated with normal or leaking conditions. There remains a need to engineer a particular solution using the commercial products deployed in a way that a leak will influence the fiber optic cable and, therefore, provide evidence of the leak. The following presentation summaries describe two (2) such product lines.

8.4.1   Presentation 1 – DiTEST LTM
Dana Dutoit – Omnisens, SA

Dana Dutoit gave this presentation regarding their fiber optic leak detection capabilities. The website is http://www.omnisens.com. Presentation slides are available as Appendix L in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points included:

1. Omnisens has been around throughout the 1990's studying Brillouin scattering in optical fibers. They were spun off in year 2000 from a research center in Switzerland. Application development followed.

2. Enabling technology is a DiTest analysis system that excites the fiber and analyzes results, combined with a communication system that allows it to be integrated with other systems.

3. The technology piggy-backs on earlier telecommunication work where efforts have been focused on extending the range of fiber optic cables.

4. The current length limit is up to 100 miles under some conditions.

5. A way of looking at it is a long length of 3-foot long sensors strung together.

6. The reliability of fiber optic cable is very high.

7. Detecting soil shift and pipeline strain are options. Detecting acoustic signatures are options, too.

8. Priorities are early detection of events and location of the events. Fibers offer the necessary range, and are fit to provide these services.

9. Tests have confirmed the detection of very small leaks with high location accuracy. Time-of-flight of light gives high location resolution.

10. Once the investment in technologies is made there are little to no operating costs.

11. Retrofit on existing lines is not a primary strategy because of risks to the pipeline due to excavation risk. The system is usually deployed on new construction as the pipeline is laid.

12. Retrofit would be easy on aboveground pipelines.

13. Leaks are detected by abnormal localized thermal signatures.

14. One hundred fifty thousand (150,000) individual 3-foot sensors can be analyzed in ten (10) minutes.

15. Low cost telecommunication cables are used when possible.

16. Whenever light is sent down the fiber, some scattering occurs. The DiTest unit examines the magnitude of a change in wavelength (color) of the light to determine whether any scattered return light indicates a temperature excursion.

17. Time-of-flight indicates the position of the source of a scatter event.

18. Most of the time standard cables are used in the interest of economy. There are a wide variety of cables available for almost any environment.

19. A by-product of using multi-fiber (usually twelve [12]) fibers is a high speed communication link between sites. Leak detection only requires a few fibers. Part of the cost of fiber optic deployment can be allocated to a dedicated communication infrastructure.

20. There are numerous arctic-rated cables available.

21. A graph of the temperature profile was shown. Any local change in temperature relative to the profile can indicate a leak.

22. Various Summer/Winter profiles can be created to serve as references.

23. The system can trend the history of a particular fiber location for evaluation with respect to the baseline. It can also examine the spread of the temperature adjacent to the event site vs. time.

24. The system does rely on a temperature event for detection of a leak. Consequently, certain pipeline construction techniques may preclude Distributed Temperature Sensing (DTS).

25. In liquid environments, the elevated crude oil temperature is a source of the temperature anomaly. Fiber placement is usually below the pipe where gravity would draw the leaked oil downward.

26. In gas environments, the expansion of gas provides a cold temperature excursion. Fiber placement is usually above the pipe.

27. Actual positions are often around 15 centimeters from the pipe to shield the fiber from normal temperatures while maintaining sufficiently close proximity to ensure a leak would affect the temperature of the fiber at the leak site.

28. Ground movement cables can be located up to 3 meters from the pipeline or attached directly to the pipeline.

29. They considered (only in concept) methods of retrofitting fiber optic leak detection on the TAPS pipeline. They have not done this yet, but they have looked at doing it.

30. Case studies for ground movement by measuring strain in the glass fiber were given. The cable can handle cyclical strain much better than copper which would work-harden.

31. These cables are a little different and are mounted to transfer strain to the cable.

32. An example of the Oooguruk system was described. It monitors a multi-phase pipeline where scour was a concern. Thirty-three (33) erosion events were identified, located and dealt with where necessary. There were no leaks as yet.

33. A case study of a German brine pipeline was discussed. The system was designed to see temperature change of one degree (1°) Centigrade (C). A temperature rise above the threshold

showed a rise of three degrees (3°) C per minute with a longitudinal growth of one-half (0.5) meters per minute.

34. A Peruvian LNG pipeline over the Andes mountain range was discussed. It had a communication-type cable and a strain cable installed during construction. A half-meter deflection over an 18-meter span was detectible. In 2010, a significant strain was detected and mitigated. Another was detected in 2011.

35. Several pipeline projects are complete. By the end of 2012 there will be thousands of miles protected by their systems.

36. A number of various kinds of events were detected and reported.

37. PRCI has verified Omnisens specifications by testing.

38. Intrusion monitoring is an option.

The evaluator asked if DTS has ever been considered as an add-on to meter-based systems to provide the shape of the temperature profile.

> Dana Dutoit indicated it had not been used for that purpose.

> Alex Albert (Schlumberger) indicated that Schlumberger had used their DTS system to monitor the temperature profile on a sulphur line to ensure it remained hot enough to flow.

The evaluator asked if they had any cases where acoustic fiber optics are used for leak detection.

> Omnisens has some in South America but they are not at liberty to divulge the company's name.

The evaluator said the reason he asked the question was that he had seen that technology reproduce the sound of shovel strokes in sand 100 feet away from the cable; indicating the possibility that detecting any acoustic emissions emitted from the leak should be easily discoverable by fiber optic tools.

The evaluator asked if the extreme temperatures in Alaska actually worked to their advantage as opposed to where the fluid temperature is close to the temperature of the environment.

> Dana Dutoit indicated this is true and that, when the temperature of the fluid is close to cable temperature, it is more of a challenge. In the Alaskan environment, there is a more recognizable leak signature.

The evaluator said, in the case of two (2) phase flow, there could be a cooling effect from escaping gas and a warming effect from the release of liquid. He asked if it would be appropriate or a waste of resources to deploy a cable below and above the pipe to ensure sensitivity to either condition, or would there be a situation where there would more likely have the liquid migrate upward to a cable over the pipe.

> Dana Dutoit responded that there may be cases where it would be beneficial to have a cable above and below the pipe. Some operators elected to use a single cable below the pipeline because they are more interested in detecting a thermal increase of a hot crude oil release.

The evaluator asked if, given the sensitivity of the technique, the cable is a little bit away from the pipe since it is necessary to shield the cable from the fluid temperature under normal conditions, would the distance affect the detection time more than any other parameter because of the time required for the fluid to migrate to the cable or the time required for heat to be conducted through the wet soil.

> Dana Dutoit indicated this was the case. They have had discussions regarding cable locations for more convenient installation of the cable because it is likely to be affected no matter where it is in the trench.

The evaluator asked if there are any differences in cable used in acoustic detection vs. DTS.

> Dana Dutoit said standard telecommunication cable with a gel fill couples the acoustic signal with the fiber very well.

The evaluator asked if DTS is affected after a ground shift. He asked if any affect was temporary or permanent.

> Dana Dutoit indicated the cables used in DTS are "loose tube" telecommunication cables where the cables are not under stress. Even at high levels of elongation, the fibers do not see stress so they operate normally. Other components are designed to transfer any stress from the DTS fiber.

Evaluator Comments

It was not that many years ago when the potential of fiber optic technology to measure temperature along its length was demonstrable in the laboratory. In the early days of the development of the technology, distances between stations limited its practical use and there were no commercially available products that supported pipeline applications. Those products that did exist were not as easily integrated with external systems as they are now.

The technology has matured greatly and Omnisens produces commercially available products that are easily configurable to recognize pipeline leaks any time a leak would create a temperature anomaly, either by direct contact of fluid with the cable or by enhanced heat flow from the pipe to the cable through soil saturated by oil. It is noteworthy that information of interest is not the actual temperature of the cable, but temperature anomalies in the thermal profile of the cable. Measurement resolutions down to one (1) meter, with peak and average temperatures collected for each segment, provide an ability to detect leak conditions and monitor the spread of fluid in the trench at the leak site.

Fiber optic technology can provide primary leak detection services in multi-phase flow conditions where leakage of either gas or liquid contents would affect the cable. It may be especially useful where meters are expected to be inaccurate due to multi-phase flow and where longer multi-phase lines are subject to fluid behaviors such as phase change and slugging that thwart meter-based algorithms. It is also an excellent secondary method where meter-based solutions are deployed as a primary leak detection method. Given the requirement of a one percent (1.0%) of daily throughput and meter accuracy limitations, this method may provide greater sensitivity than is possible using meter-based tools on high throughput lines. In this case, accurate leak location is a secondary benefit of the technology.

Pipeline operators considering the deployment of fiber optic technology must work with the vendor to develop a good deployment strategy that will accomplish the operator's leak detection goals. The technology is not recommended on existing buried pipelines due to the excavation risk to the pipeline.

However, it is recommended for existing above ground pipelines. Another benefit of this technology can be a high speed communications network for both data and voice applications.

8.4.2   Presentation 2 – Integriti Pipeline Monitoring System
Alex Albert – Schlumberger Oilfield Services

Alex Albert gave this presentation regarding their fiber optic leak detection capabilities. Their website is http://www.slb.com. Presentation slides are available as Appendix M in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant points include:

1. Mr. Albert credited Dana Dutoit regarding his description of how fiber optic technology works.

2. Integriti was developed based on customer desires.

3. Schlumberger's onshore and subsea surveillance offices are around the world.

4. Technologies include distributed temperature measurements, discrete fiber optic measurements, and high resolution point measurements, as well as subsea sampling at the tree.

5. Capabilities include subsea communication and control.

6. They can monitor all assets from the reservoir, flowlines, and refineries to the end user.

7. Many things can happen to pipelines including corrosion, geo-hazards, and intrusions that can create a leak.

8. The main interest in leak detection is detecting the loss of the wall where a leak may occur. Designs reduce the potential of damage, but leaks will occur.

9. Schlumberger came into fiber optics because occasional monitoring of pipelines was not sufficient. Fiber optics were chosen for simplicity, ability to detect and identify an event, to locate the event in real-time, and no maintenance requirements existed. It needs to cover the span between stations and have a good measurement range. Leak prevention is desired, not just detection.

10. Schlumberger provides ongoing service, such as data monitoring and analysis.

11. Hardware includes Distributed Strain and Temperature Sensor (DSTS) and Distributed Vibration Sensor (DVS) for vibration measurements in a 19-inch rack.

12. They use standard telecom fibers, either single or multi-mode. Single mode is used for longer ranges and multi-mode is used for shorter ranges. Multi-mode has a larger core size.

13. Retrofits can include using existing fibers or deployment of new fibers on the line. The latter is more difficult.

14. Systems are intrinsically safe. If a cable is cut, leak detection works up to the location of the cut, and the system will alert the controller that the cable has been cut.

15. Schlumberger has pre-qualified a cable configuration for a standard ruggedized cable configuration. It was destructively tested with good results.

16. They can do installations using stainless steel control lines where few measurements are needed. They have a patented method of pumping fibers through the control line after the line is installed.

17. Mr. Albert agreed with Dana Dutoit's discussion regarding fiber location.

18. The system provides a Geographic Information System (GIS)-based web-based software system that shows an image of the line with information superimposed. Applications exist to propagate data to field staff on smart phones with incident location and supporting data.

19. An advanced user interface offers views of specific signatures of the event.

20. Schlumberger can review historical data for reference.

21. Client-specific visualizations are an option.

22. Integration with SCADA is also an option with many protocols.

23. A table of principles was presented to illustrate methods of detecting issues. Issues included temperature anomalies from gas expansion due to a leak, acoustic vibration from a leak, ice and strudel scour, etc.

24. These systems can be combined to work for all these applications.

25. Think of the fiber as a one (1) dimensional radar with fiber molecules interacting with the light. Light is reflected in all directions, including straight back. Light is reflected from all points on the fiber and the system can analyze data at one (1)-meter resolution.

26. Light speed is used to locate the source of an anomaly.

27. Multiple techniques provide benefits.

28. Range is 100 kilometers in either direction for a total range of 200 kilometers.

29. No terminations are needed.

30. An example of multiple measurements was presented to illustrate accumulated evidence of a leak.

31. Strain growth over time can be detected. A sudden shift of ground or a landslide would have an acoustic signature, along with a strain indication. Backhoe operation would likely be detected from about 200 meters away. A human walking would be detected at 30 meters. Digging signatures would be recognized. Cable damage may be heard and strain measured.

32. Case studies were presented. Schlumberger is not quick to commercialize their new products. A great deal of work went into proving the potential benefits of the product by modeling the thermal gradients around the pipe to determine what a leak would actually look like to the system.

33. A 5-millimeter leak test was shown.

34. They tested a 36-inch pipeline 20 meters long that was constructed as a test bed. The model of the pipeline was verified.

35. Cable positioning was tested using sand and gravel beds. Vibration was detected in about thirty (30) seconds with no sensitivity to cable location around the pipe. In the case of DTS, the cable closest to the leak was first to detect the leak.

36. Another test in the Middle East on a 20 inch flow line and a 12 inch export line included DVS (for early warning) and DSTS, using temperature only for leak confirmation.

37. The BTC Georgia Pipeline was protected against third-party intrusion from Schlumberger's England office. A vibration event was moving up and down the pipeline very quickly and was reported to the field. They were flying a security helicopter back and forth along the pipeline.

38. A 40-kilometer long sulfur pipeline was monitored to maintain a minimum flowing temperature above one hundred thirty degrees (130°) C. The DTS capability was used with a custom operator interface.

39. Another example involved subsea operations of a heated production line where the goal was to avoid wasting money on heating the line when it was already hot enough to prevent wax build-up and hydrate formation. The system used the stainless steel control line with a fiber installed to monitor the line. The heater was controlled by the system to operate only when the temperature dropped below minimum levels.

40. It is an integrated solution with options for many kinds of applications.

Questions and Responses

The evaluator asked for more detail on single and multi-mode fibers.

> Alex Albert explained that you can get higher resolution with multi-mode fibers because you can pump more light into them. The disadvantage is a range limit of around 12 to 15 kilometers. Single mode allows operation up to 100 miles.

The evaluator asked, if given the example pipelines provided in the RFI, how many fibers would likely be deployed to implement all their tools concurrently.

> Mr. Albert explained that they use one (1) fiber per application so they would want three (3) fibers for vibration temperature and strain. After 50 kilometers, it is necessary to amplify signals for temperature and strain and, after about 30 kilometers, for vibration. They have a patented optical amplification system that needs no extra hardware. It needs another fiber for each time you optically amplify the signal. This would occur every 25 kilometers where it is needed. You would need twelve (12) fibers for a 100-kilometer line.

The evaluator asked if it was possible to determine a distance of a vibration source to the fiber based on the length of cable affected by the vibration and the intensity of the signal, given the apparent angle from the source.

Mr. Albert said it could be theoretically done, but they have not done it yet. People are looking into it and, perhaps in the future, it will be done.

The evaluator asked if they could correlate the hole size and pressure with a probable leak detection threshold with the acoustic tool.

Mr. Albert said it is hard to correlate that because the fill can be widely different and the vibrations emitted can vary. The pipeline would need to be modeled before that can be predicted.

The evaluator asked, if given the combination of DSTS and DVS, could the system send information regarding a leak to SCADA with the constituent data for analysis, and possibly to assign a severity level based on agreement among methods.

Alex Albert confirmed his understanding of the question and acknowledged they can completely customize how alarms are created. He added that they can even combine signatures to determine a probable passing animal versus a human walking toward the pipeline.

The evaluator asked if DVS would be a good candidate for bundled pipelines from offshore wells.

Mr. Albert said they are doing that now for sand management and flexible risers.

Evaluator Comments

This presentation confirmed the maturity of fiber optic technology and demonstrated its applicability in pipeline leak detection and in pipeline security monitoring. The foundation of the Schlumberger products is based on the same underlying technology as was described in the previous Omnisens presentation. Schlumberger, however, appears to have fast tracked their product deployment into their entire spectrum of services they traditionally support. That is not intended to suggest a less than deliberate focus on each application, but rather to acknowledge that Schlumberger has a long history of involvement in numerous activities where fiber optic technology can be applied. This has given them practical experience in a wide variety of implementations that are of interest in Alaska.

Their fiber optic technology is also suitable as a primary method for flow lines where meter-based techniques are impractical and multi-phase pipelines where meter-based solutions are not expected to perform well. Their system is also applicable as a secondary leak detection method to complement meter-based solutions.

8.4.3   Session 4 Follow-up

Questions and Responses

From the audience to Omnisens: What is the cost per kilometer for fiber optic leak detection solutions?

Dana Dutoit explained that a lot of theory goes into the selection of fiber optic cables, installation methods, and infrastructure development. We are generally less than one-tenth percent (0.1%) of the new pipeline construction cost. Low fiber count telecommunication cables typically cost less than one dollar ($1) per meter.

From the audience to Schlumberger: What are the power requirements to use fiber optics?

Alex Albert explained that it depends on what units are being used. Basically, regular 120 VAC is required.

From the audience to Omnisens and Schlumberger: Do you splice fiber to install it on new pipelines that are constructed in pieces? How do you handle challenges of installing it on pipelines in below ground applications?

Alex Albert explained that there is a close coordination between the cable installer, typically a telecommunications group, and the construction company. There are splicing methods, but we usually install it over long distances. Splicing is a very well-developed field craft in the telecommunication industry. When fiber was first deployed, splicing a fiber was a scary thought. But, these days, it is highly automated and done by a very user-friendly method. Dovetailing the laying of the pipeline with the fiber deployment is something they get involved with.

Dana Dutoit added that the equipment sensitivity specification assumes splices will exist along the pipeline. As long as you use good cable, the number of splices will not be a problem.

From the audience to Omnisens and Schlumberger: Can you discuss the feasibility of retrofitting aboveground North Slope pipelines?

Dana Dutoit explained that Omnisens has not retrofitted an above ground pipeline yet, but he described how easy such a retrofit would be.

Alex Albert added a reminder about his example using the stainless steel fiber and that there are numerous methods of installing a fiber and channeling lost fluid to it.

From the audience to Schlumberger: Regarding sensitivity, with the aboveground installation how sensitive would the system be to animal noise in the area?

Alex Albert explained that they have not done testing regarding background noise, but he expected wind noise to be a factor. But, they always monitor background noise from a week to a month before deployment so they can identify the signals and tell the system to ignore that signature even though it is recorded.

From the audience to Schlumberger: Can you ignore traffic near the cable?

Alex Albert answered yes; they had a pipeline near the highway and they could configure the system to ignore the traffic.

From the audience to fiber optic presenters: Are you able to sense oil and water moving along the ground from under a pipe rack?

Someone answered yes, but only if it produces an audible signature.

After clarification, the context is for warm liquids.

Dana Dutoit explained that over a 40-mile range PRCI tests indicated the detection is within three degrees (3°). Over shorter ranges, resolution is better, up to 0.1 degree (0.1°) C if the system is zoned that way.

Alex Albert agreed that the delta T that can be seen is smaller for short distances.

From the audience to fiber optic presenters: What precautions need to be taken to prevent mechanical damage or vandalism to the cable?

Alex Albert indicated an acoustic system will detect a vandal near the pipe. Major equipment will be housed in a station where it is protected.

Dana Dutoit concurred and added that additional precautions, such as stainless steel jackets, are an option.

From the audience to fiber optic presenters: Are these single mode fibers?

Dana Dutoit explained that Omnisens uses single mode fiber exclusively.

Alex Albert said they have different systems that use single or multi-mode fiber.

From the audience to fiber optic presenters: Are there intermediate stations needed along the pipeline?

Alex Albert indicated they can use optical amplifiers every 25 kilometers instead of stations with more equipment for up to 100 kilometers in either direction. These can be integrated into one (1) readout back at the control room.

Dana Dutoit added that, when you are targeting high resolution leak detection, PRCI tests confirmed about 40 miles (20-up, 20-down) yielded good results. If you go extended distances, there are performance tradeoffs. At maximum span, 200 kilometers per system is a reasonable expectation.

From the audience to Schlumberger: Can signal boosting be done at the stations?

Alex Albert explained the optical pumping units located where the interrogators exist. There is only fiber in the field.

From the audience to fiber optic presenters: What is the expected sensitivity on a buried subsea pipeline?

Dana Dutoit indicated there is no clear-cut answer without knowing the sea temperature and how a leak would affect the environment where the cable is located.

The evaluator explained that, in his look at fiber optic applications, in many cases when you bury a cable with a pipeline in Alaska, you will have some kind of a thermal disturbance that can be sensed. You may be lucky enough to have direct contact between heated liquid and the fiber, increased thermal conductivity of the saturated soil between the pipe and the fiber, and other times you may have cooling of the soil as gas percolates up to the surface. With crude oil, it will spread and likely influence the temperature of the soil around the pipe. If your fiber is close enough, you should see a temperature excursion. It is all about engineering a situation to ensure the fiber sees a thermal excursion of some sort.

Dana Dutoit added that, on the Oooguruk project, they modeled results of crude oil at a certain temperature leaking into the environment to determine what the delta T would be, and how long it would take to develop. There is no clear answer without looking at the application.

Alex Albert agreed and invited anyone who wants to run a test to let him know.

From the audience to fiber optic presenters: What applications cannot be covered by your system?

Dana Dutoit said this came up during PRCI tests. Though methods exist to install cable at relatively high speeds, the owner-operators perceived any excavation to be an integrity risk. Retrofitting below ground pipelines is a problem for that reason.

Alex Albert agreed and added that applications where oil temperature in the line is near soil temperature, a delta T might not be seen. Higher pressure lines may create an acoustic signature that the DVS tool can sense.

8.5   Session 5: Leak Detection Infrastructure Component Technology

Session 5 was focused on leak detection infrastructure component technology, such as Coriolis meters and transmitter technology. Both presentations were given by divisions of Emerson Process Management. Neither Micro Motion nor PCE Pacific provided copies of their presentations for distribution, though both presentations made extensive use of graphics to aid in understanding the presentation content. However, company websites can be visited for the purpose of collecting product data needed to determine suitability for use in any application.

8.5.1   Presentation 1 – Micro Motion Coriolis Flow and Density Meters
Chris Connor – Micro Motion, a Division of Emerson Process Management

Chris Connor provided this presentation. The website is http://www.micromotion.com. Additional details regarding the presentation are only available from Micro Motion. Significant topics included:

1. References were made to Dr. Morgan Henrie's (MH Consulting) presentation.

2. The focus was on how Coriolis meters work, comparisons of flow measurement technologies, computational pipeline monitoring, and how flow measurements fit in.

3. Coriolis meters give fluid density, direct mass measurements, volume, and temperature.

4. A description of an illustration of vibrating tubes was given.

5. Two (2) pickoff coils are used. With no flow, the signals from the coils are in phase with each other. With flow, the twist caused by the flow through the excited tubes results in a phase shift between pickup coil sensors. The delta T is directly proportional to mass flowing through the meter.

6. The natural vibration frequency at which vibrations are caused is a function of the tube characteristics combined with fluid characteristics.

7. Light crudes will require a higher vibration frequency to maintain the natural frequency. The goal is the least amount of energy for the maximum signal.

8. As product of greater density moves through the tubes, the frequency has to be increased.

9. The frequency is directly proportional to the density of the fluid.

10. Temperature is measured too, and is used to compensate for the stiffness of the tube.

11. Volume can be provided, along with concentration, degrees API, and standard volume.

12. Approvals include API.

13. Applications include measuring flow of crude oils, natural gas, drilling mud, custody transfer, leak detection, etc.

14. Inherent advantages over other technologies include lack of moving parts, wider range, better accuracy and better repeatability.

15. A graph illustrating a Coriolis meter and a Positive Displacement (PD) meter was described.

16. Changes in viscosity affect turbines, but not Coriolis meters.

17. Coriolis meters can be installed right off an elbow in tight situations.

18. A matrix on the slide was explained.

19. Not having to adjust for viscosity, temperature and pressure allows good real world performance.

20. Other advantages include diagnostics, such as smart meter verification.

21. Erosion and corrosion can affect calibration. Freezing the tubes with water can balloon the tubes and affect calibration.

22. Diagnostic test tones at various frequencies and energy levels can check the meter's calibration by comparison with historical data.

23. Measurement of two (2) phase flow is improving. Big issues are slug flow and bubble flow where the mixture is homogenous. Batches, such as transitions from an empty pipe state to a full pipe state, then to an empty pipe state, are an issue.

24. Errors were up to twenty percent (20%) for multi-phase flow in the early days. Now, accuracy can be improved.

25. Decoupling was explained as gas being entrained in the liquid and requiring more energy to overcome the dampening effect. Transient flow conditions are dealt with using digital signal processing.

26. Fairly long tube sets allow driving the tubes at lower frequencies. At lower frequencies, there is less decoupling and error in two (2)-phase flow measurements. An illustration was provided for this.

27. The meter can detect gas or solids in liquids.

28. The Pipeline and Hazardous Materials Safety Administration (PHMSA) performed a study between 2007 and 2009 saying only nine percent (9%) of all leaks were detected by leak detection systems.

29. An illustration was shown regarding leak detectability.

30. A study by Ed Farmer and Associates (EFA) was described and illustrated.

31. When Coriolis meters replaced other meters in an example, sensitivity changed from one percent (1%) to one-tenth percent (0.1%).

32. Detection time was half the original time.

33. Another EFA study showed performance at different observation intervals.

34. Coriolis meters offer five one-hundredths percent (0.05%) mass accuracy on liquids, one-tenth percent (0.1%) on volume, high turndown ration of 20:1 at those specifications, and at one-half percent (.5%) accuracy, a 100:1 turndown is possible.

35. Density accuracy is great.

36. Meters can be installed in parallel and meters can be proved individually.

37. They can be operated in series for redundancy. This was illustrated.

38. Uncertainty can be reduced using multiple meters.

39. Applications include custody transfer and leak detection.

Questions and Responses

The evaluator suggested a vision of gas and liquid in the tube and that higher frequency vibration might measure the mass more accurately if the gas and liquid do not exchange positions in the tube because the gas cannot move around the liquid quickly. He observed that, at lower frequencies, there seemed to be better correlation between gas and liquid motions. He asked Mr. Connor to explain this further.

> Chris Connor explained decoupling with an example of a bubble in liquid where the gas bubble wants to travel further in the tube than does the liquid, which changes the effective center of mass, which leads to measurement error. To the evaluator's point, intuitively, the faster you shake the tubes the less inertial impact [presumably because fluid acceleration is interrupted], but we see the faster you drive it the more decoupling [between the developing fluid inertia and the tube walls] occurs.

The evaluator asked about wet gas where the liquid is not significantly in contact with the wall.

> Chris Connor said it is a similar situation. If it is a mist, the liquid does not have much effect in measuring the gas. If liquid collects on the tube wall, this can create a significant cause of error in gas measurement. Leveraging this to detect presence of liquid is a possibility. The density of wet gas can be measured. Many times people only want to measure gas flow.

The evaluator asked if there are any flow conditioning requirements for Coriolis meters.

> Chris Connor explained that for two (2)-phase flow high velocities and well-mixed fluids are important. For single-phase applications, there are no flow conditioning requirements. But, there are installation best practices. These are having tubes up for gas environment and tubes down for a liquid environment to allow for two (2)-phase anomalies to flow through. It is all about sizing the meter to limit pressure loss and maximize performance in each installation.

Evaluator Comments

Coriolis meters have in recent years gained market share because of the maturity of the technology and increasing capacity to cover larger pipelines. Their overall benefits are such that some companies standardize on them for custody transfer applications, especially where flow rates vary. While these meters are a very good fit for pipeline leak detection, it is important to remember that the uncertainty related to flow measurement at the meter location pales in comparison to linepack uncertainty as flow imbalances are measured. It is the linepack uncertainty that leads to a high false alarm rate or masking of real leaks. As the presenter indicated, good metering is the foundation of meter-based leak detection. However, good meters cannot substitute for effective linepack analysis algorithms. Installing high quality meters on lines whose operations have linepack uncertainty issues will not compensate for limited algorithm sophistication.

8.5.2   Presentation 2 – Smart Wireless and Wireless HART
        Kurt Weedin of PCE Pacific Inc., Partnering with Emerson Process Management

Kurt Weedin provided this presentation regarding their line of wireless transmitters. The websites are http://www.pcepacific.com and http://emersonprocess.com/SmartWireless. Presentation slides are available as Appendix N in Shannon & Wilson's report titled *Pipeline Leak Detection Technology Conference Report* and dated December 2011. Significant topics included:

1. PCE has an exclusive relationship with Emerson Process Management, but is a private company.

2. Rosemount measurements are used in numerous systems in Alaska.

3. Wireless HART protocol is an international standard, part of HART 7, IEC 62591.

4. Various vendors make compliant hardware.

5. A map of installations was shown.

6. Plant networks are high bandwidth, maybe in support of Radio Frequency Identification (RFID), safety systems, etc.

7. Field networks are the focus today.

8. Typical questions include how long do batteries last.

9. Lithium batteries are designed for low power applications with local display.

10. Updating every thirty-two (32) seconds, three thousand fifty-one (3,051) unit batteries will each last ten (10) years.

11. A chart showed various transmitters and battery life. The ten (10) year limit is arbitrary because there is a question about shelf life of the batteries.

12. The ability to identify when a measurement was taken is important in leak detection.

13. Each node is time synchronized with the gateway. A description of a mesh network was described.

14. Synchronization between devices is to one (1) millisecond. Actual time interval calculated is to a microsecond level.

15. Update rates are limited by power. With this limitation removed, update rates can go to the fifty (50) millisecond intervals.

16. They use a Time Division Multiple Access (TDMA) protocol for managing traffic via scheduling frames and slots.

17. Acknowledgement responses (ACKs) are sent to guarantee transaction completion.

18. Time slots were illustrated and described.

19. Spread spectrum radio techniques are used.

20. Data propagation was described.

21. The basic architecture was illustrated and described.

22. The gateway can connect to SCADA via Modbus™ RTU protocol, TCP/IP, OPC, Delta-V (Emerson's proprietary protocol), etc.

23. Units can operate 700 feet apart in standard mode, one-half mile in extended mode, and a little further with the new method.

24. An example of integrating the TraceTek 5000 cable system with the network was given.

25. A drawing of a mesh network with various radii showed the network architecture.

26. Gateways draw only three (3) watts and can be used with field generated power.

27. Measurement types were listed.

28. New products include acoustic sensors and pig detection.

29. The 3051S is the same as in the wired world.

30. Temperature measurement can have one (1) to four (4) channels.

31. Vibration monitoring targets pumps.

32. Various other transmitters were discussed.

33. The 702 provides a way of reading dry contacts and pulses. Pig detection is an application. Controls can be sent through the 702 to drive the load. It also integrates with the TraceTek Fast Fuel Sensor (TTFFS) point detector or the TT-5000 cable for remote leak detection. Up to three (3) TTFFS sensors or up to 500 feet of TT-5000 cable. Combinations include one (1) sensor and 300 feet of cable, and two (2) sensors and 150 feet of cable. Total resistance is the limitation.

34. Detection of sheen is a good application. Buoy mounted transmitters are an option.

35. The audience was invited to offer ideas regarding product suggestions.

Questions and Responses

The evaluator asked if their displays would survive harsh Alaskan winters.

> Kurt Weedin explained that there were no reports of permanent damage to the displays.

The evaluator referenced a comment that each device knows when to wake up. He wondered if that pertained to transmissions only.

> Kurt Weedin explained the scheduling process in which the transmitter awakens to receive messages as well as to send them.

The evaluator asked about the receiver being active to receive messages.

> Mr. Weedin said they periodically listen to see if the gateway is active to download schedules.

The evaluator asked if they have a temperature transmitter with a retractable probe to allow pigging.

> Mr. Weedin said they do not.

8.5.3   Session 5 Follow-up

Questions were solicited.

From the audience: With a ten (10)-year battery life for wireless transmitters at seventy degrees (70°) F, what would be the life at minus forty degrees (-40°) F?

> The answer offered indicated a life of eight (8) years.

From the audience: Can you talk about encryption in the wireless transmitters?

> Mr. Weedin said you could spend a few hours talking about security. It is very secure and has been tested to Achilles Level 1 and AES 128-bit encryption with rotating keys. Access to the gateway is via Virtual Private Network (VPN).

From the audience: What about safety certifications for Zone I or Zone II use?

> Mr. Weedin said the wireless transmitters are classified FM Class I, Div I Zone 0, and intrinsically safe.

The question was indecipherable.

> IEC certification is expected to Zone 0.

From the audience to Chris Connor: Can you talk about your meter's capability with multi-phase lines for leak detection and, if they can, what threshold?

> Chris Connor said these are not multi-phase devices, but they give good performance with certain flow regimes. We have no data showcasing the meters on multi-phase flow.

Evaluator Comments

The products described in these presentations are applicable on any pipeline project, subject to review of their environmental specifications with respect to the expected operating environment. Coriolis meters are growing in popularity in the lower forty-eight (48) states because their reputation for reliable accurate measurement is good. It is important to determine whether the available leak detection algorithm would perform better using volumetric measurement or mass measurement. Short lines with changing injection temperatures due to batched operation may require volumetric data since the mass in each barrel injected can vary as batches sources and corresponding temperatures are switched. With a short line, balancing barrels by volume, if this problem exists, could be superior to balancing by mass since the mass of an injection barrel and discharge barrel may differ significantly even though the volumes match. RTTM technology handles this issue natively and benefits greatly from accurate flow measurement.

The wireless transmitters are interesting in several ways. However, long scan intervals of thirty-two (32) seconds for a ten (10)-year battery life are not desirable in a leak detection system. It is preferable to have scan frequencies at around or under five (5)-second intervals. Consequently, power may need to be distributed to transmitters in order to avoid occasional battery replacement. If power must be distributed, wired communication infrastructure can be installed at the same time. It is also necessary to verify the wireless data communication system will operate during adverse weather conditions.

9.0   COMPLIANCE

Alaska pipeline operations are governed by 18 AAC 75 *Oil and Other Hazardous Substances Pollution Control* as well as federal regulations. 18 AAC 75 requires operation of a leak detection system for a crude oil transmission pipeline to be capable of detecting a leak of one percent (1.0%) of daily throughput. Under many cases, this is not a high threshold to reach for some technologies, but is impossible for other systems. Unfortunately, where systems thwarted by temperature profiles inherent in the particular pipeline operations are installed, pipeline operators simply declare achievement of required performance to be not technically feasible rather than implementing a technology more capable of compensating for the temperature profile.

9.1   18 AAC 75.447 Conference Requirements

18 AAC 75.447 requires a technology review conference every five years for the purpose of determining the status of existing technologies and determining which technologies are superior to others. It is also charged with the responsibility of identifying technological breakthroughs that may improve leak detection performance in Alaska. Section 2.2 *Revolutionary Technology* explains the evolution of commercially available leak detection tools. None of the tools described in presentations are considered breakthrough technologies. Instead, they are implementations of technologies with a focus on pipeline leak detection where the technology may have been applied first in other industries. To illustrate product maturity, all presentations described existing pipeline projects and/or a customer base for the products being offered.

Considering technologies rather than particular commercial products, all technologies directly applicable to pipeline leak detection discussed are already deployed somewhere in Alaska. Sections 4 *Meter Based Technology* and 5 *Non-Meter Based Methods* and their subsections describe the inherent strengths and limitations of various technologies as well as explain the issues involved in selecting a leak detection method for a particular pipeline. The Alaskan environment and its effect on pipeline operations thwarts lesser meter-based solutions due to inadequate algorithms to deal with the temperature/density issues on some pipelines. However, the same conditions strengthen the benefits of fiber optic leak detection tools based on distributed temperature sensing. In no case does the Alaskan environment thwart all implementations of various leak detection technologies. As stated above, some individual tools are thwarted while others based on the same traditional field measurements are capable of performing well. Presentations given during the conference clearly described the applicability of the various products discussed including representative projects.

This report does not simply declare one technology or commercially available product to be suitable for any or all pipelines operations in Alaska, nor can it legitimately declare one tool to be superior to others in all cases. Sufficient operational details for all pipelines in Alaska to make such a declaration based on specific operations, geographical locations or physical environment is not possible on a case-by-case basis. However, Sections 4 and 5 provide the necessary information to make such an evaluation possible by staff with detailed familiarity with any given pipeline.

Section 4.3.3 *Real-Time Transient Model* describes the benefits provided by RTTM technologies on pipelines that have temperature profiles that thwart lesser meter-based technologies. However, as stated many times during the conference by many presenters, selection of leak detection products should be done with consideration of pipeline operating conditions. Simply stating temperature issues thwart achievement of required performance on a pipeline where the leak detection system does not employ

RTTM technology should not be accepted as evidence that attainment of performance goals is not feasible. Instead, it should indicate a shortcoming in matching the inherent leak detection algorithms (leak detection product) with the pipeline's operating conditions.

High consequence areas, and areas where remediation would be difficult, may warrant secondary methods sensitive to fugitive oil in order to limit the released volume to well below the one percent (1.0%). Such solutions may be more suitable for primary solutions than meter-based tools under some conditions. However, such tools, while potentially more sensitive than meter-based tools, are not capable of measuring leak sizes or rates. Detection of the leak quickly should be paramount over measuring the quantity of lost fluid in real-time. Consequently, selection of a tool based on its ability to measure the lost volume of oil over one that can reduce the volume lost is not recommended. Instead, SCADA based over/short tabulations and trends should be used for that purpose if the segment containing the leak is bound by meters.

10.0 CONCLUSION

Pipeline leak detection technology in Alaska has a record of being thwarted by thermal issues that cause false alarms; thus requiring elevated leak detection thresholds and/or long observation intervals to verify persistence in any apparent imbalance. Linepack uncertainty due to thermal issues may also mask real leaks until accumulated fluid losses finally overwhelm linepack uncertainties. There are commercial products available that can significantly improve leak detection performance on these pipelines by minimizing the uncertainty in the linepack by modeling heat transfer and the density profile of the fluid in the pipeline.

The conference clearly showed that commercial products exist to improve pipeline leak detection performance in Alaska. As stated above, the known problem is the effect of not being able to understand the temperature profile along the pipeline and its effect on fluid density; i.e., on linepack uncertainty. The problem was shown to have the predictable result of thwarting meter-based solutions that attempt to assess linepack contents with simple approximations.

One meter-based tool described in the conference, ATMOS Pipe®, makes no attempt to analyze changes in linepack. It has been tested, and is reported to have shortened detection time in a fluid withdrawal test from fourteen (14) hours to under one (1) hour compared to the incumbent system on the pipeline. This tool did not have a thermal model but used its statistical processes to determine the probability of a leak based on behavior "learned" during configuration. Its algorithms allowed early development of confidence that a leak was evident. It should be noted that this tool can be deployed with a thermal model in order to compete with RTTM-based products that can accurately track changes in linepack.

This report describes various technologies and their inherent applicabilities. It does not make any declarations regarding what technology is applicable on a given pipeline, especially on example pipelines coarsely described as multiphase with little else in the way of characteristics that would enable or thwart the successful use of any particular technology or product on the line. It is worth repeating that the engineering effort leading to the selection and deployment of any particular leak detection system should involve the candidate vendor's engineering team to assess the suitability of their product for the unique operational characteristics of the line.

Mandated leak detection performance identifying a leak equal to one percent (1%) of a day's throughput should <u>not</u> always be considered a satisfactory level of protection with regard to environmental due diligence. Instead, this should be considered an absolute minimum level of performance for pipelines where this would be a small released volume. Where large linepack uncertainty is inherent in a pipeline's

operation, methods should be required that reduce that uncertainty and, therefore, facilitate reducing the volume lost in the event of a leak. Acceptable practices and due diligence should require selection and deployment of a leak detection method that minimizes the quantity of released fluid under any circumstances or pipeline operating conditions. This may involve both a sophisticated CPM solution combined with a secondary method that either extends sensitivities or shortens detection times.

Some external leak detection technologies do not require flow measurements, and therefore cannot estimate leak rates. Tools based on these technologies may be worthy of deployment as a primary system even though verification of compliance with required volume loss metrics is not possible. On large capacity lines, their potential to limit released fluid volumes can be significant. In such a case, engineering analysis of applicable parameters, such as fluid migration patterns, should be performed in lieu of fluid extraction tests where such tests would compromise future leak monitoring. These tools may also be applicable as a secondary leak detection method to extend leak detection sensitivity or shorten detection time. Conceptual testing can involve a representative pipe segment with an applicable fluid at representative temperature and typical trench fill. Such tests can be witnessed by interested parties and results used where applicable to justify the selection of that tool or technology for a similar project.

As important as detecting a leak is, the controller's response is equally critical. There have been several cases where the leak detection system detected an actual leak and declared an alarm which was ignored by the controller. Training programs should be developed around actual fluid withdrawals in order to verify that controllers recognize and respond to leaks appropriately. Such tests can have a wide spectrum of benefits if first responders and cleanup contractors are involved to test their responses.

11.0   FUTURE TECHNOLOGY DEVELOPMENT SUGGESTIONS

Real-time transient models require configuration of heat retention and flow parameters in order to accurately assess the temperature/density profile. Setting these parameters usually involves tuning the model such that modeled fluid temperature downstream matches the actual measurement; assuming there remains sufficient fluid temperature to show that it is still above the environmental temperature. It is usually desirable to have a temperature measurement some distance downstream of the injection point in order to serve as a reference based on actual measurements where fluid temperature would have dropped, but would still remain above environmental temperature under all conditions. This may be an outlying RTU downstream of the injection point or the next station downstream.

It would be interesting to see a joint effort between a RTTM vendor and a fiber optic vendor to apply DTS technology to show the shape of the thermal profile, if not measure the actual thermal profile. Such a use of DTS technology could significantly simplify adaptation of the system to accommodate major changes in flow rates. If a second fiber is deployed in a manner that it is bonded to the pipe and insulated from external influences periodically, it could give accurate fluid temperatures after a period of time to attain a new quiescent thermal state after a change in flow. Parameters could be recorded in a library of operational parameters and with specific details for particular segments, such as river crossings and other anomalies affecting heat flow in a very local sense.

APPENDIX B

ATMOS INTERNATIONAL, INC. – ATMOS PIPE® AND ATMOS WAVE
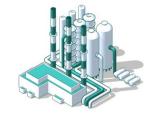
Pipeline Application Solutions

September 2011

About ATMOS

- ATMOS is a company specialised in software for pipeline leak detection, design, operations and business applications.

- In addition to software leak detection soulutions, ATMOS also provides ATMOS Wave, a LDS system that also includes hardware for pipeline leak detection.

- ATMOS is the leader in the Pipeline Online applications with more than 400 pipelines over 150 projects installed online world wide

- ATMOS products are used on pipelines from 300 meters to 8,000 km networks, from 3 mm to 2 meters diameter.

About ATMOS

- <u>Worldwide Locations</u>

  - **Manchester, UK** (Engineering, Service, R&D & Marketing/Sales) established 1993

  - **Anaheim, CA, USA** (Engineering, Service, R&D & Marketing/Sales)

  - **Costa Rica** (Engineering, Service & Marketing/Sales)

  - **Beijing, China** (Engineering, Service & Marketing/Sales)

  - **Prague, Chez Republic** (Marketing/Sales)

  - **Singapore**, (Marketing/Sales)

- Certified to Lloyd ISO9001: 2000 plus TickIT

- 36 Agents-Partners Worldwide

Online Applications Experience

Category	Pipelines	Length (km)
Crude Oil	152	22,445
Multi & Refined Products	120	10,971
LNG & Natural Gas	72	21,808
LPG & Critical applications	49	4,882
Water & Brine	6	197
Multi-phase	3	87
Totals	402	60,390

Examples of ATMOS Clients

- AIOC, Azerbaijan, Georgia, Turkey
- AGIP, Libya
- Air BP, UK
- Air Liquide, Belgium, Singapore, USA
- BAFS, Thailand
- BP, Azerbaijan, Belgium, UK, USA, Algeria
- Centrica Gas Distribution, UK
- CNNOC, China
- DOW Chemicals, Brazil, Germany, Spain, USA
- EGAT, Thailand
- El Paso Energy, USA
- ENBRIDGE, Canada, USA
- EXXONMOBIL, UK, USA, Italy, Africa, Russia
- GAIL, India
- GASSCO, Norway
- Guangdong Gas, China
- Ineos (BP Chemicals), Belgium, UK
- KaztransOil, Kazakhstan
- LUKOIL, Russia
- Ministry of Defense, UK,
- NWO & NDO, Germany
- OIL – Oil India Ltd, India

- Oldeval, Argentina
- ORC, Oman
- Plantation Pipe Line Company, USA
- PDO, Oman
- PETROBRAS, Brazil, Ecuador
- PTT, Thailand
- PETRODAR, Sudan
- PETROCHINA, China
- PETRONAS, Malaysia
- TRANSNET , South Africa
- PDVSA, Venezuela
- PETROVIETNAM, Vietnam
- Qatar Petroleum, Qatar
- Rotterdam Rijn Pijpleiding, Germany, Holland
- RELIANCE, India
- SONATRACH, Algeria
- SAKHALIN ENERGY, Russia
- SHELL, Australia, Canada, New Zealand, Nigeria, UK, USA, Singapore, Russia
- Singapore Ministry of Defense,
- SINOPEC, China
- Sonacol, Chile
- TOTAL, UK, Belgium

Solutions for Liquid Pipelines

ATMOS Pipe: Statistical leak detection

ATMOS Wave: Rarefaction Wave Leak Detection

ATMOS LSIM: Real time transient model for LDS

ATMOS Hybrids:

- ATMOS Wave Flow: Wave plus corrected mass balance
- ATMOS Pipe with ATMOS Wave to accelerate detection time and improve leak location

ATMOS Trainer: Operator training simulator

ATMOS Batch: Batch tracking

ATMOS Pig: Pig (scraper) tracking

ATMOS OPT: Power optimization

ATMOS Software for Liquid Pipelines

Project Examples
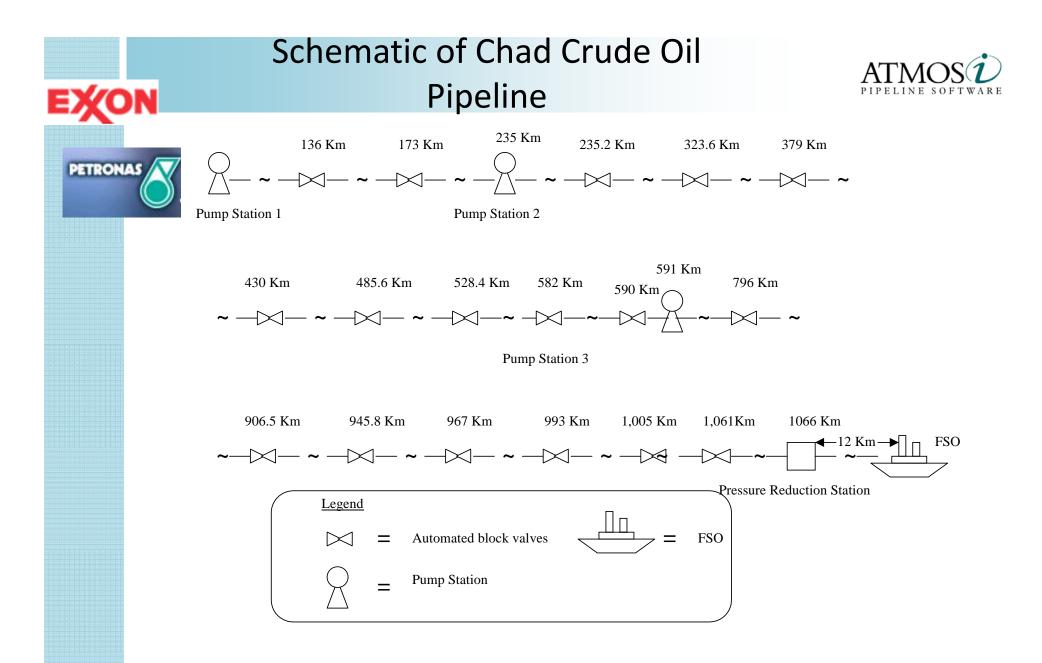
- ## Application in Chad to Cameroon Africa

- 1078 km 42"/46" Crude Oil Pipeline from Chad to an FPSO in Offshore Cameroon

- 2nd Longest Oil Pipeline in Africa

- 3 Pump Stations

- Leak Detection & Location Static & Dynamic

- Pig Tracking

- Sole Source supply

Schematic of Chad Crude Oil Pipeline

EXXON

PETRONAS

ATMOS *i*
PIPELINE SOFTWARE

136 Km   173 Km   235 Km   235.2 Km   323.6 Km   379 Km

Pump Station 1   Pump Station 2

430 Km   485.6 Km   528.4 Km   582 Km   590 Km   591 Km   796 Km

Pump Station 3

906.5 Km   945.8 Km   967 Km   993 Km   1,005 Km   1,061Km   1066 Km

12 Km   FSO

Pressure Reduction Station

Legend

⋈ = Automated block valves

🚢 = FSO

○ = Pump Station
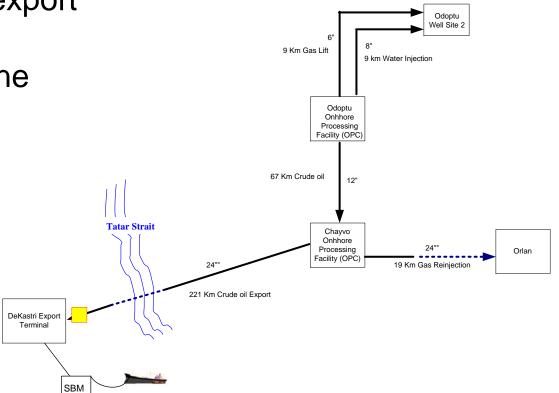
ExxonMobil, Sakhalin Island

Sakhalin Island Project

- 1 crude oil export pipeline
- 1 gas pipeline

Odoptu
Well Site 2

6"
9 Km Gas Lift

8"
9 km Water Injection

Odoptu
Onhhore
Processing
Facility (OPC)

67 Km Crude oil

12"

Tatar Strait

Chayvo
Onhhore
Processing
Facility (OPC)

24""
19 Km Gas Reinjection

Orlan

24""
221 Km Crude oil Export

DeKastri Export
Terminal

SBM

Reference: D. K Johnson

D.k.johnson@exxonmobil.com

Main Multi Product Pipeline Network
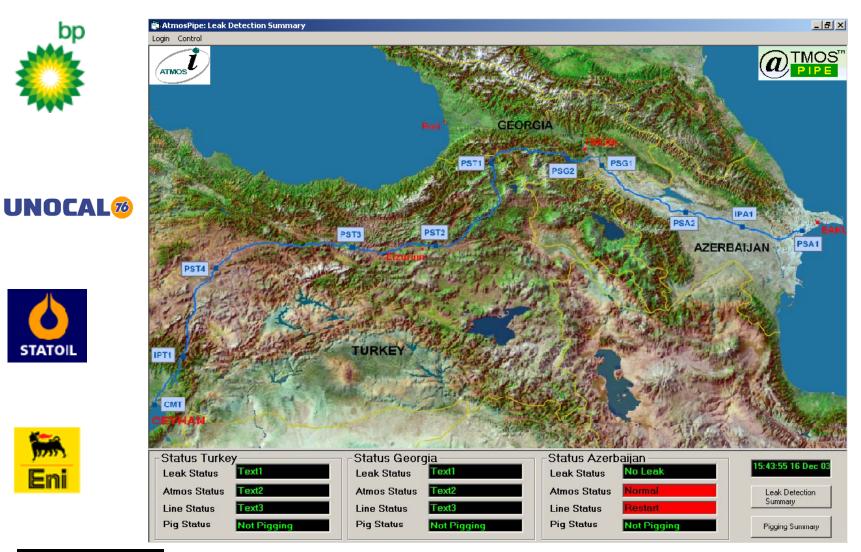
Phase 1:- 1200 km Multi Product network – completed in July 03

Phase 2:- 400 km Multi Product network – started in June 04

Reference: John Banting

 john.banting@exxonmobil.com

BP Operated 1778 km BTC Pipeline

ATMOS *i*
PIPELINE SOFTWARE

- Principal crude collection network in Gulf of Mexico
  - 35% of daily production for USA
- 532 km, 24"/30" subsea
- 3 pump stations, 4 inlets & 6 outlets
- Real time LDS
- ATMOS Trainer

Petrobras Brasil
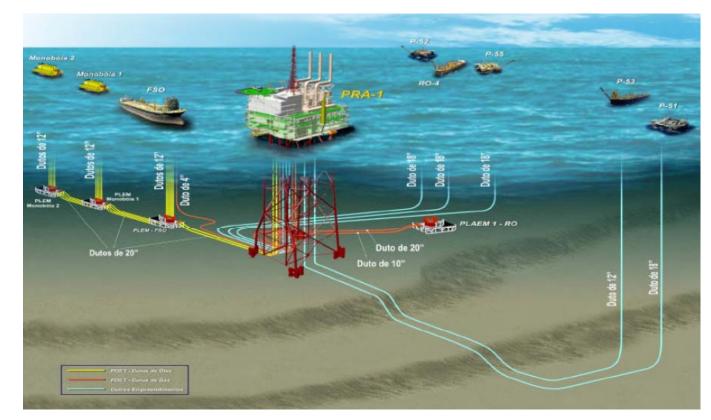
6 subsea crude oil pipelines -300 km

- – Leak detection

- – Trainer

- – Hydraulic model– off-line

2 subsea crude oil pipelines (SBM)

- – 7 km (leak detection system)

Projects With Enbridge

1. Steelman a Cromer Terminal NGL
2. Red de oleoductos de North Dakota Clearbrook Terminal to Minot Crude
3. Encana to Weyburn Crude
4. Cromer Truck to Cromer Terminal Light Sour blend
5. Cromer Truck to Cromer Terminal Medium Stream blend
6. Crude oil pipeline from Weymar to Cromer, 12" /16", 324 km
7. Crude oil pipeline from Alexander a Trenton
8. Crude oil pipeline from Grenora a Minot
9. 8" crude oil pipeline from Trenton a Beaver
10. Crude oil pipeline from Maxbass a Minot
11. Crude oil pipeline from Beaver Lodge a Minot
12. Crude oil pipeline from Trenton a Beaver 10"

2,300 km of Pipelines, 25 pump stations, 16 Delivery Stations, 13 different fluids, several delivery routes.

- **Refined Products Pipeline (RPP) and Inland Network (IN):**
  Multiproduct 1,500 Km network 8" to 20" diameter, 7 intakes, 14 Delivery points
- **Crude Oil Pipeline (COP):** Crude Oil, 675 km 16" to 18" diameter,
- **AVTUR Pipeline (AVT):** Jet Fuel, 100 km , 6" diameter

Software Functionalities:

- Leak Detection
- Anomaly Detection
- Pig Tracking
- Batch Tracking
- Pipeline Simulation
- Trainer Simulator
- Pump and DRA Optimization

ATMOS Pipe Statistical Leak Detection

What Is ATMOS Pipe?

- ATMOS Pipe uses corrected mass balance in conjunction with a patented statistical test to provide a reliable software for the detection of leaks.

- Installed on over 400 pipelines more that 40 countries on pipelines that transport a wide variety of products such as crude oil, refined products, natural gas, LNG, dangerous chemicals such as ammonia, chlorine gas and spongy liquids such as dense phase ethylene.

ATMOS Pipe – Benefits

Statistical technology (SPRT)

- Detects leaks under all operating conditions
- Minimum false alarms, 2 or 3 per year for tight line liquids

Detailed hydraulic modeling is unnecessary

- Less instrumentation
- Easier and faster to install and maintain
- Substantially reduced cost of ownership
- Designed for remote support capability

Uses industry standard interfaces

- Rapid integration with SCADA/DCS/PLC/RTU
- Results displayed through pipeline control system

ATMOS Pipe – Benefits

Real-time, Online Learning Ability

- Manages flow meter drift to eliminate false alarms
- Cheaper to maintain than other systems

Successful in over 600 real leak tests

- Reliable
- Robust
- ATMOS Pipe meets and exceeds the requirements of API 1130 (September 2007 Edition)

Optional Shut-in Module
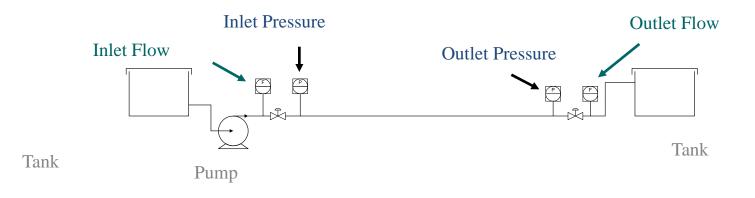
– Even more sensitive than the dynamic system and faster.

Works under all operating conditions

– Including pump start/stops, opening/closing valves, pipeline packing and unpacking.

Has never been replaced with a competitor's system

– A substantial part of our work is replacing competitor's systems.

Learns The Flow Difference Between Meters.
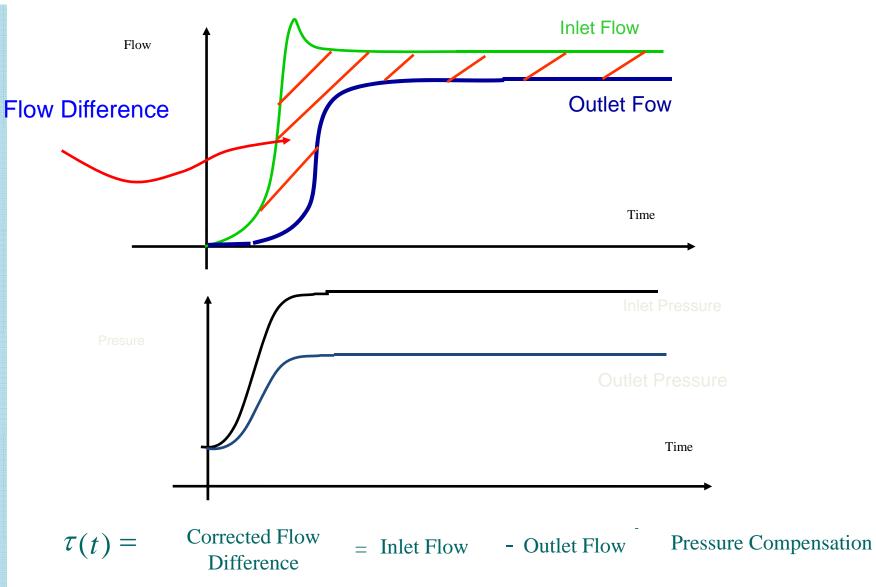
When we install any flow meters on a pipeline there will always be an error in measurement between the meters.

ATMOS Pipe learns this normal flow difference when the pipeline is in steady state.

ATMOS Pipe Technology

Flow

Inlet Flow

Flow Difference

Outlet Fow

Time

Presure

Inlet Pressure

Outlet Pressure

Time

$$\tau(t) = \quad \text{Corrected Flow Difference} \quad = \text{Inlet Flow} \quad - \text{Outlet Flow} \quad \text{Pressure Compensation}$$
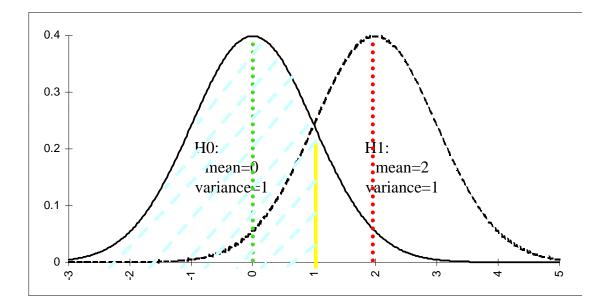
ATMOS Pipe Tedchnology

With frequent data samples available we can assume the distribution of the corrected blow difference τ is Gaussian. The system uses a hypothesis test to decide if the mean corrected flow difference has increased.

Hipothesis H0 — the mean of τ is zero
  Hipótesis H1 — the mean of τ is 2

If the majority of the data is in the shaded area, hypothesis H0 is true and a leak is less probable.

Principals of ATMOS Pipe

Sequential Probability Ratio Test $\lambda(t) = \log \frac{P_1(t)}{P_0(t)}$

Testing H_1 against H_0 at sample time t,

$$\lambda(t) = \lambda(t-1) + \frac{\Delta m}{\sigma^2} (\tau(t) - M - \frac{\Delta m}{2})$$

$\tau(t) =$ The Corrected Flow Difference $=$ Inlet Flow -   Outlet Flow - Pressure compensation

$M =$ The mean corrected flow difference (what is normal for the pipeline)

$\Delta m =$ The leak size that we are seeking
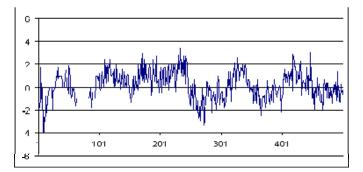
The Apparent Leak Size = The corrected flow difference – the mean corrected flow difference

The apparent leak size = $\tau(t) - M$
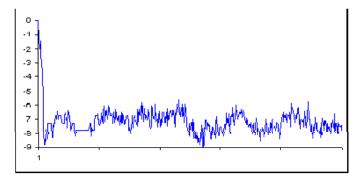
Sequential Probability Ratio Test (SPRT)
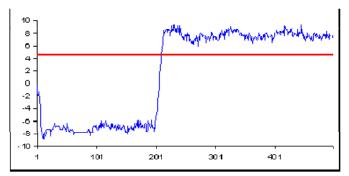
Flow Imbalance over 500 Samples, the Average
Value Remains at 0.14 — Normal Metering Error

Flow Imbalance over 500 Samples, the Average
Value Increases from 0.14 to 2.14 at Sample 200
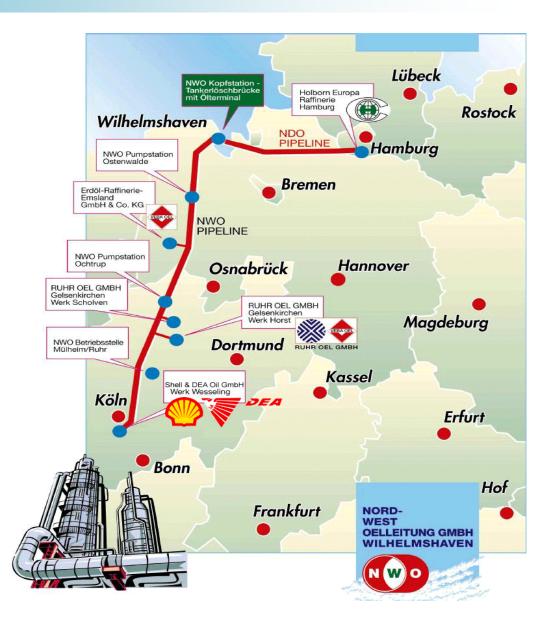
Lambda Indicates the Flow Imbalance Has Not
Increased by More than 0.5 t/h, with 99% Confidence
(Lambda is less than 0)

Lambda Confirms the Flow Imbalance Has Increased
by More than 0.5 t/h, with 99% Confidence at Sample
210 (Lambda Goes above 4.6)

Data collection at 3 second intervals

Data validation to identify faulty instruments

Leak detection under all operating conditions
– steady state - normal operation
– transient - pump stop/start, valve open/close, delivery change-overs

Estimation of leak size and location

Minimum detected leak size: 1%

NWO: 353km, crude oil, summary

	Density (kg/m³)	Viscosity (cSt @ 10°C)	Batch Size (m³)
Minimum	798	2.8	93
Maximum	925	309.2	111,245

47 test leaks at different location (Aug 8, 2002 – May 21, 2004)

12 in steady state, 35 during transients

including pump starts/stops, supply and delivery changes, and control valve movemets

All leaks detected   No false alarms
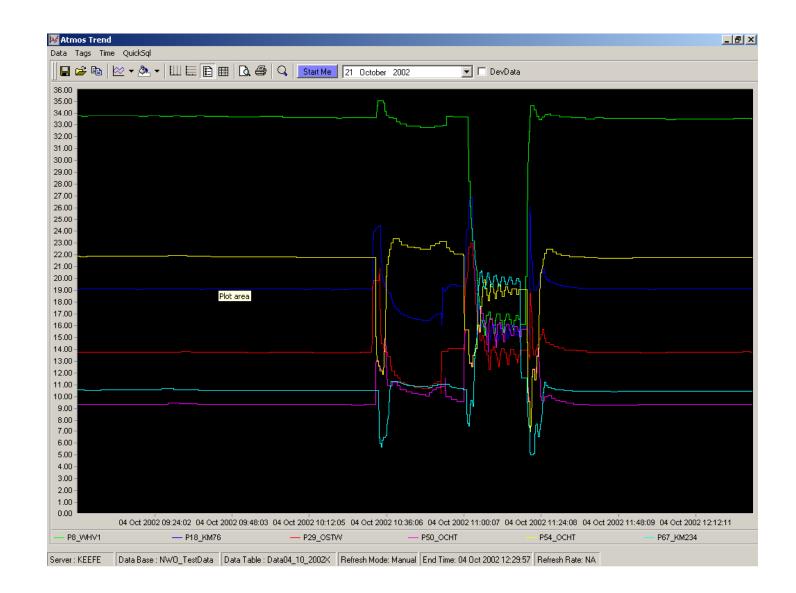
Leak Test #6 - Flows
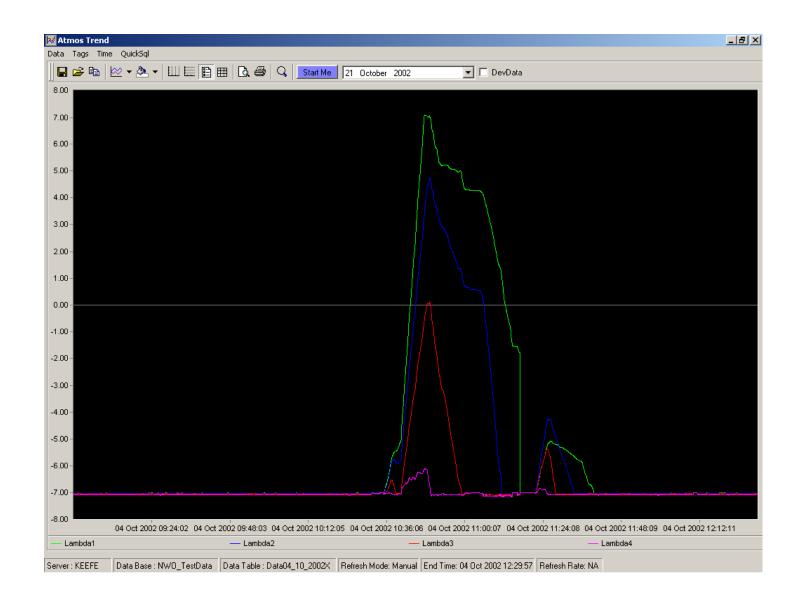
Leak Test #6: Pressures

Test #6: Response of Statistical Variables

Alaska Installations

- Installed on a crude oil network in Alaska since 2009.
  - Very low false leak alarm rate

    tested frequently and detects leaks as much as 14 times faster than the corrected mass balance system installed on the same network.

    Example: A test in April 2009

    1% leak detected by ATMOS Pipe in 52 minutes

    In the same test the 1% leak was detected by teh corrected mass balance system in 14 hours and 9 minutes

Alaska Installations

- Tested this summer on a refined product system in Alaska.
  - False leak alarm rate is over 1000 times better
  - detects the 1% leak in less than 60 minutes
- scheduled for permanent installation this month .

Leak Detection Using Rarefaction Waves
ATMOS WAVE

Rarefaction Wave

- When a leak occurs in a pipeline , the pressure drops.

- This initial drop is a dynamic effect caused by the inability of the fluid to respond instantaneously to the leak.

- The pressure continues to diminish at slower rate as the pipeline unpacks.

- This type of pressure drop is a rarefaction wave.

- Begins as a small hemisphere centered at the leak hole

- Changes shape as it interacts with the curved pipe wall, eventually becomes two plane waves propagating down the pipe in both directions at the speed of sound.

- WAVE captures and analyses these waves.

Why Design ATMOS Wave?

- Find very small leaks or theft <1%
  - Limitation in CPM - Flow meter performance
- Detect these leaks in minutes, not 1 hour
- Better Leak Location 1 to 2%
- Low false alarm rate

Features and Benefits

ATMOS *i*
PIPELINE SOFTWARE

1) Detects small leaks and theft

2) Pressure differentials not absolute pressure

 – Thus leak detection is not dependent on the accuracy of the flow meters.

3) Can be deployed on pipeline segments as long as 100 km with NO intermediate sensors.

Features and Benefits

3) WAVE does not need to integrate flow discrepancies

4) Very low false alarm rate.
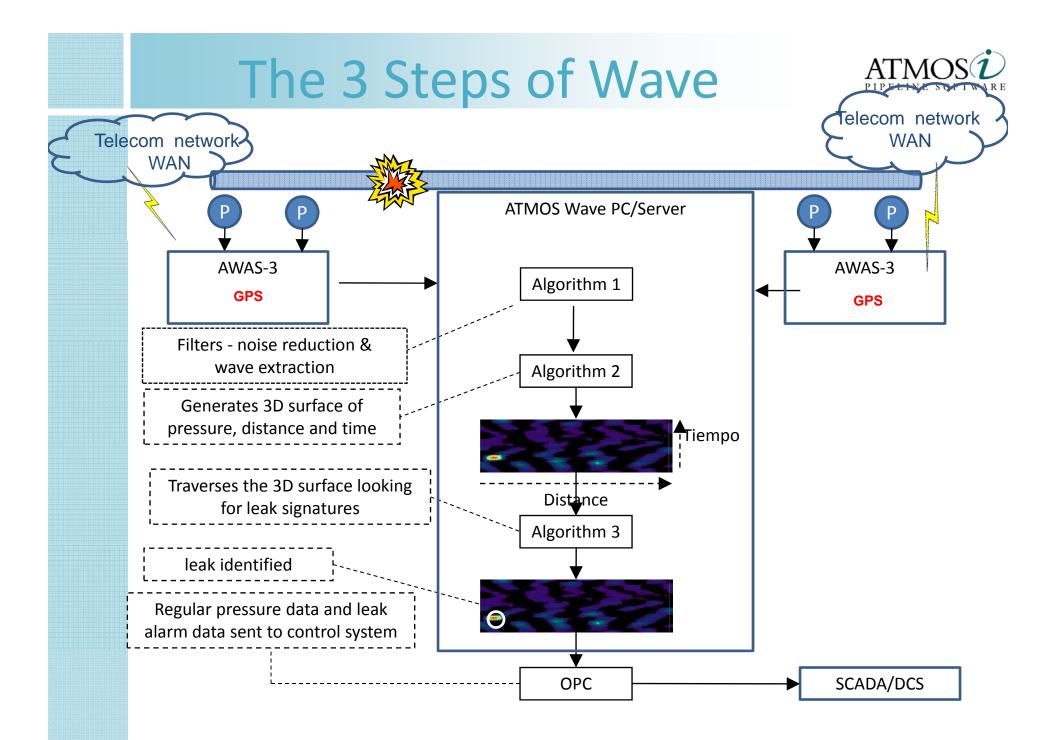
Packing events are seen as "normal" events in the 3-D mathematical space generated by the algorithm.

If a leak occurs when the pipeline inventory is changing, WAVE will see it with maximum sensitivity
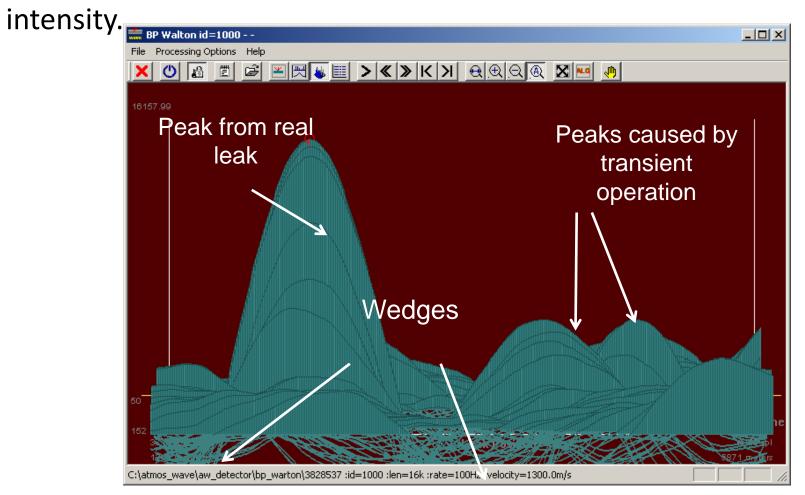
5) Theft commencement & finish detected as separate events

6) WAVE does not use individual leak events to activate a leak alarm

7) All of the mathematical functions are continuous.

The 3 Steps of Wave

ATMOS*i*
PIPELINE SOFTWARE

Telecom network WAN

Telecom network WAN

P   P

P   P

AWAS-3
GPS

AWAS-3
GPS

ATMOS Wave PC/Server

Algorithm 1

Filters - noise reduction & wave extraction

Algorithm 2

Generates 3D surface of pressure, distance and time

Tiempo

Distance

Traverses the 3D surface looking for leak signatures

Algorithm 3

leak identified

Regular pressure data and leak alarm data sent to control system

OPC

SCADA/DCS

Analyses ALL Pressure Data

- WAVE uses ALL pressure data from BOTH ends of the pipeline to construct a 3D map, showing time, distance and wave intensity.

Only peaks that are 20 times higher are reported as leaks

Unique: Detects Small Leaks During Transients

• Competitors only compare the local pressure data to historical data each end - a decision with limited data - great difficulty differentiating a leak from a transient. That is why they have frequent false alarms.

• ATMOS Wave uses all data from both ends of the pipeline to make an informed decision. Compiled in central processor to 3 D map that makes it easily to differentiate a leak for transient behavior.

BP- Test in UK

- The tests were performed between Monday, December 7 and Thursday December 10, 2009.

- 12.24 KM long jet fuel pipeline

- Diamater 8"

- Formal flow = 160 m^3 /hr

- Normal inlet pressure: 35 a 35.6 barg

- Normal outlet pressure: 4.0 a 3.85 barg

- Operted in batches

- Only from 12 pm a 7 pm

-

Test Procedure
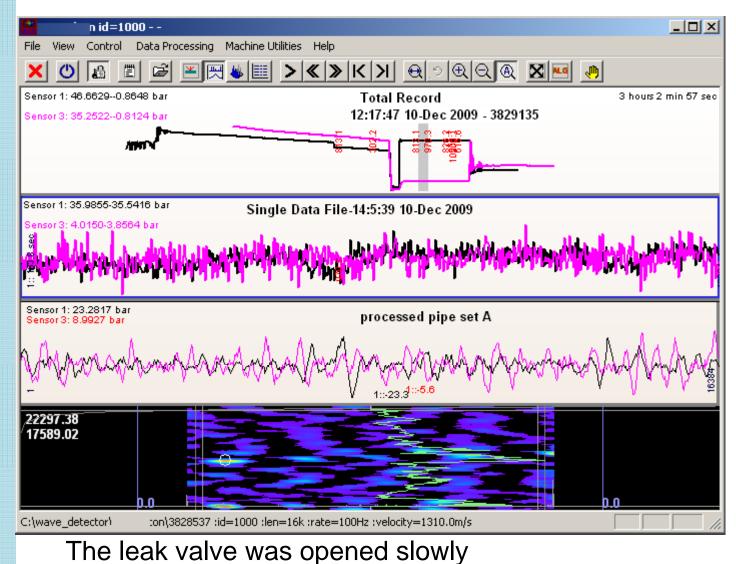
- Data collected over 3.5 days

- System processed the data for the first 3 days to prove no false alarms

- 8 leaks on 4th day at a valve site 770 m downstream of the inlet sensor

- First leaks when line was shut-in

- leaks lasted only 10 seconds

- Each new leak was introduced one minute after previous leak ended

Dynamic Leak- #4

- A leak of 3.42 liters was detected in 10 seconds, 20 liters /min.
- 2:09 PM - 0.78% of normal flow

The leak valve was opened slowly

Enbridge Pipeline Leak Test
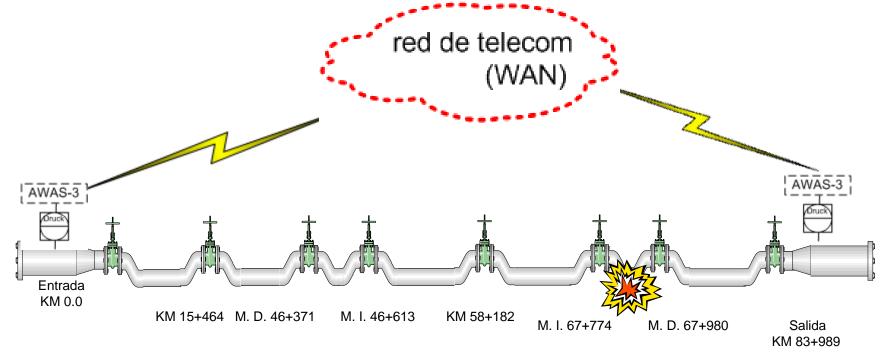
- 8" Crude pipeline, 19.3 KM long
- Test dates: 10 July to 14 Jul.y 2010

- Detected 14 leaks, both shut in and flowing
- Examples
  - 0.08% detected in shut-in and located to 345 meters.
  - 0.8% during a gravity transfer at a pressure of de 5 PSI. Location accuracy of 173 meters.
  - 1% that was opened very slowly was located with an accuracy of 332 meters

83.8 km Multi-Product Pipeline in Mexico

- Diesel and gasoline, 18", 83.9 km
- Test were made from 7 September to 10 September, 2010
- Distance between the pressure sensors is 83.9 km
- All of the 22 leaks were detected in 1 a 2 minutes
- Site of the leaks: Valve station at 67.98 km from the inlet

Tests on 10 Sept. 2010

Test	Time	Size	Distance
1	14:00	0.5%	74.0
2	14:09	1%	65.05
3	14:17	2%	67.29
4	14:25	1%	66.63
5	14:30	2%	66.74
6	14:33	1%	67.50
7	15:00	2%	66.55
8	15:03	1%	66.48
9	15:10	0.5%	66.82
10	15:21	3%	66.84
11	15:24	2%	66.63

Leak site was at 67.9 km

The Complete Toolbox

- No two pipelines are exactly the same in their hydraulic behavior. The pipeline hydraulics can change depending on numerous factors, including the products transported, the pipeline elevations and on how the pipeline is operated. Therefore one leak detection method may be the best on one pipeline while a different method may be the best on another pipeline. This is why ATMOSi has developed a portfolio of pipeline leak detection methods.

What Now?

- Clients who use ATMOS Pipe are testing ATMOS Wave as a secondary LDS
  - Faster leak detection
  - Improved leak location
  - The same guaranteed reliability of ATMOS Pipe
  - Redundancy in LDS

APPENDIX C

KROHNE OIL & GAS – PIPEPATROL LEAK DETECTION AND LOCALIZATION SYSTEM (FKA GALLILEO)

KROHNE

achieve more

PipePatrol
KROHNE Pipeline Monitoring System
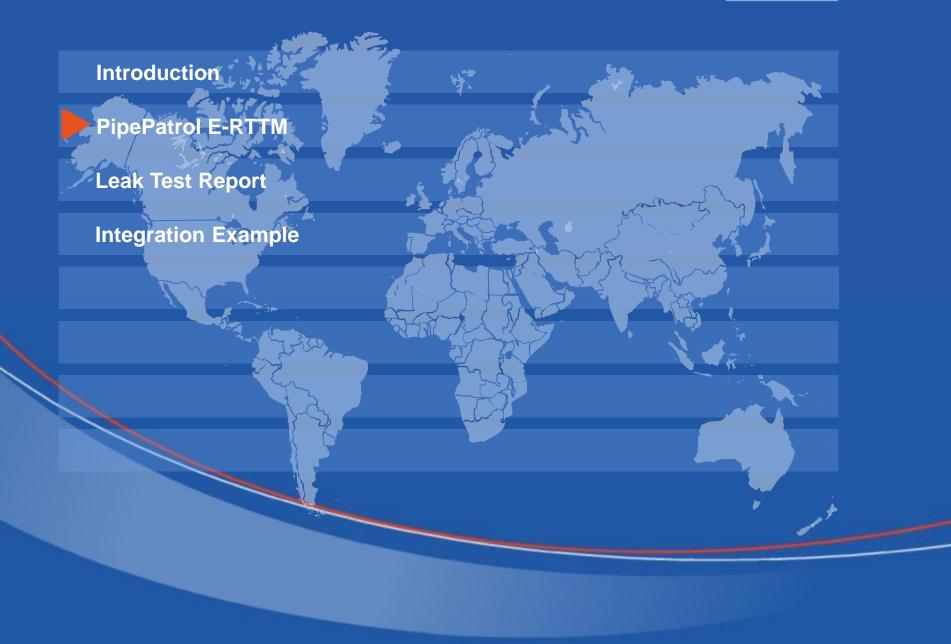
KROHNE

What is a good Leak Detection System?
Performance Cryteria according to API 1155

Sensitivity

- **Detect small leaks fast**
- Typical smallest detectable leak rate app. 0.5% (nom. Flow)
- Very fast detection time for small leaks, typically < 10min

Reliability

- **Produce no false alarms**
- Extraordenary small false alarm rate (<2 per year)
- Reliable detection of smallest leaks

Robustness

- **Don't shut down the Leak Detection if a component fails**
- Robust Hardware with redundancy options
- Fall back strategy if sensors fail

Accuracy

- **Calculate accurate leak rate and position**
- Leak localisation accuracy typically between 1% und 2% of the segment length
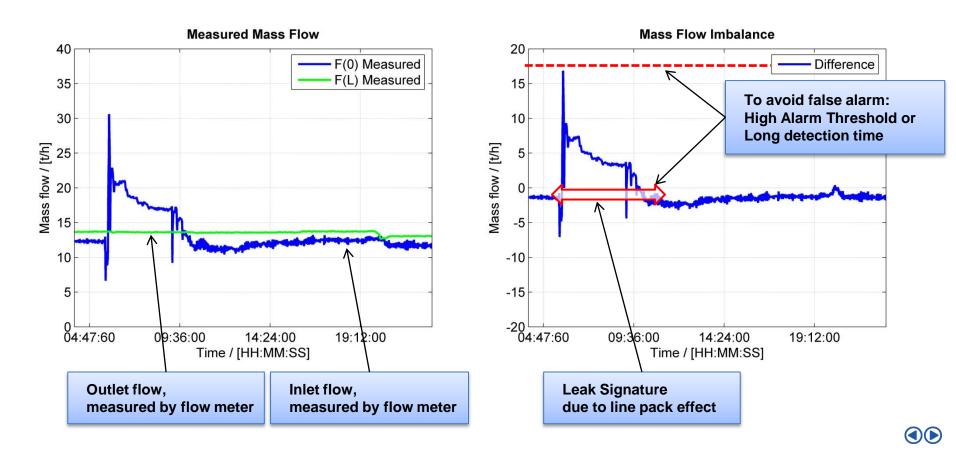
The Technology of PipePatrol

Result of a traditional balancing system
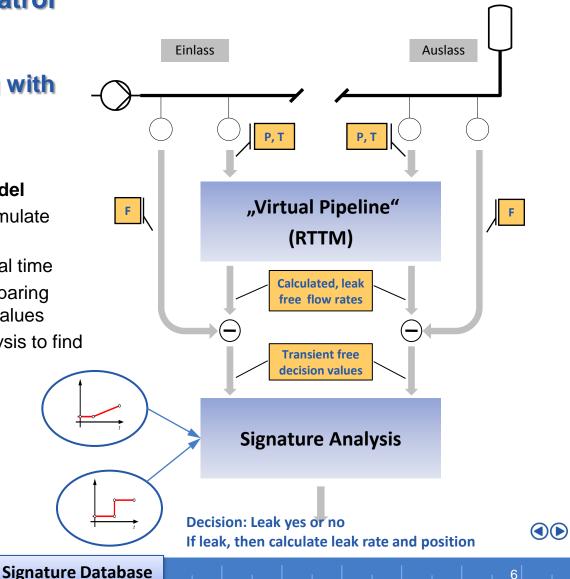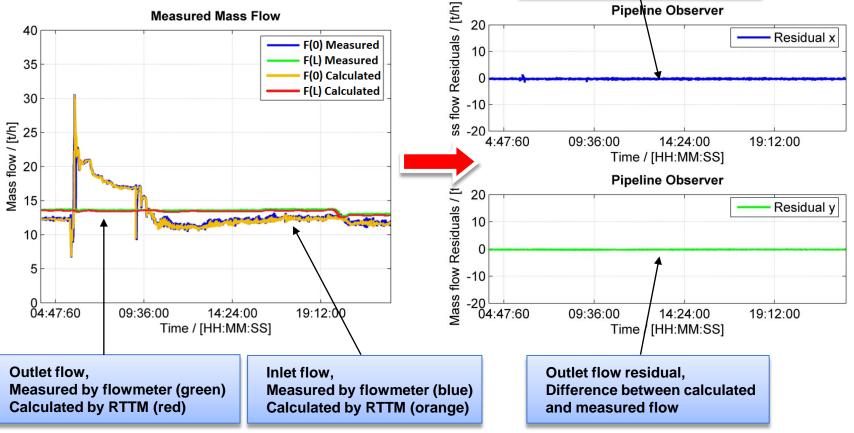
The Technology of PipePatrol

Result of PipePatrol E-RTTM Technology

Inlet flow residual, Difference between calculated and measured flow

Outlet flow, Measured by flowmeter (green) Calculated by RTTM (red)

Inlet flow, Measured by flowmeter (blue) Calculated by RTTM (orange)

Outlet flow residual, Difference between calculated and measured flow
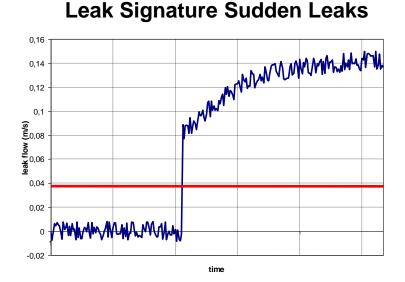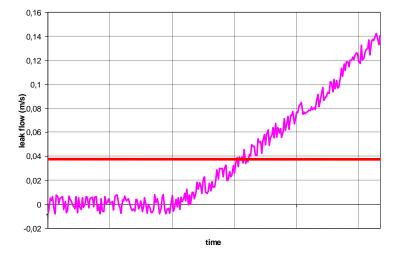
Signature Analysis

Avoiding False Alarms Using Leak Pattern Analysis

Leak Signature Sudden Leaks

Applies to accidents: Rupture, caterpillar
Applies to theft: Shot into Pipeline, Open ball valve, etc.
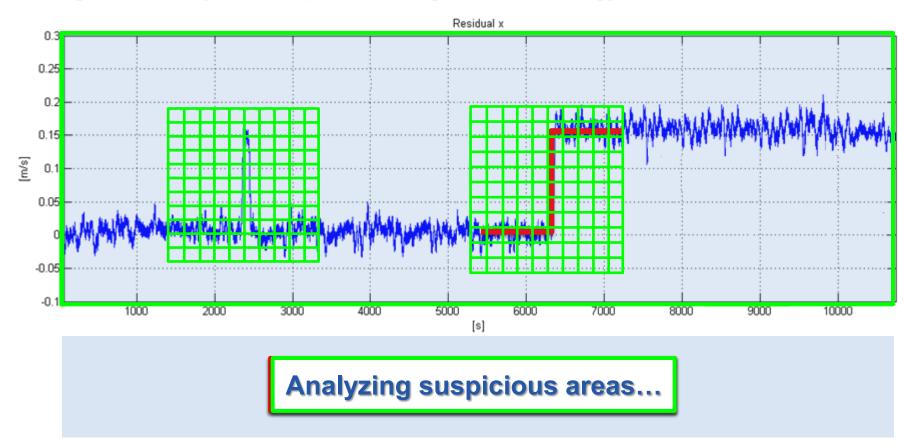
Leak Signature Creeping Leaks

Applies to corrosion/leaking sealing

Signature Analysis

Signature Analysis uses pattern recognition technology to detect leaks:

Analyzing suspicious areas…

PipePatrol Principle

▶ **Simultaneous calculation of leak position with three different methods**

● Gradient Intersection
● Time-of-Flight
● Extended Time-of-Flight

▶ **Main advantages**

● Combines strengths, avoids weaknesses
● Provides excellent overall accuracy

KROHNE

Shell Deutschland Oil GmbH

▶ **Product**

- Nine refined liquid hydrocarbons (incl. diesel, heating oil, naphtha)

▶ **Pipeline**

- Length 31 km
- Diameter DN 250 (10")
- Underground
- Bidirectional

▶ **Instrumentation (new)**

- Flow at in- and outlet (UFM)
- Pressure at in- and outlet
- Temperature of product at in- and outlet
- Temperature of ground at in- and outlet

▶ **Flow**
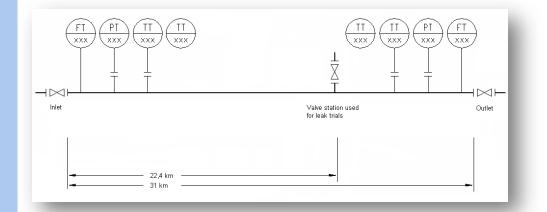
- Design flow 600 m3/h
- Design pressure $40 \cdot 10^5$ Pa (40 bara)
- Transients during start-up, shut-down, batch changes, direction changes

TÜV witnessed Leak Test Data
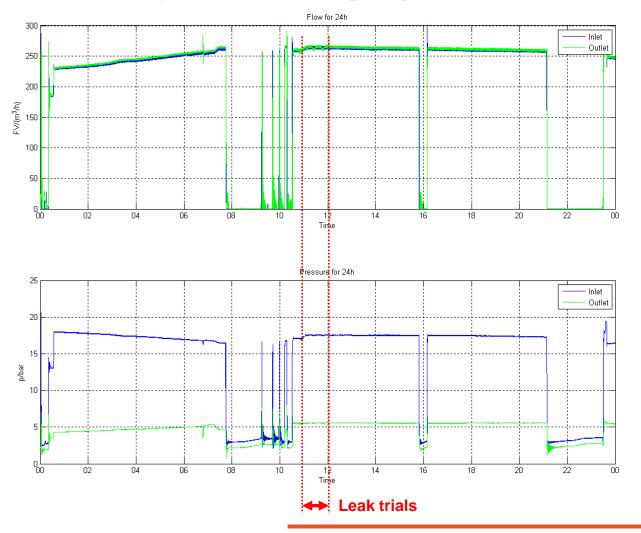
▶ **Leak characteristics**

- 22.4 km from inlet
  (app. 70% of length)
- Spontaneous leak by opening valve

▶ **Leak test**

- Naphtha with leak rate of 5 m3/h
  (app. 0,83% of design flow)
- Leak created for 5 minutes with 3
  consecutive runs
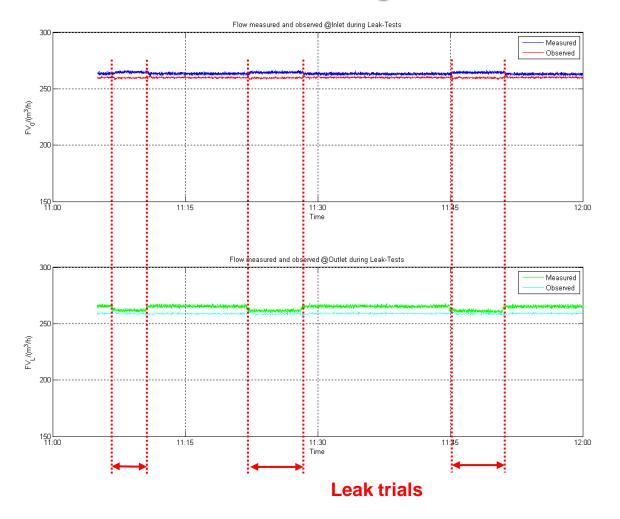
Measured flow and pressure during day
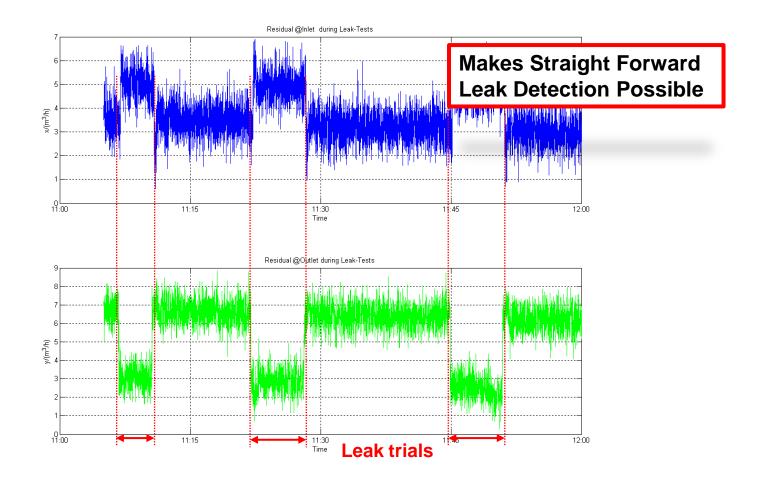
Measured and calculated flow during leak trials

Leak trials

Residuals x and y

Makes Straight Forward Leak Detection Possible

Leak trials

Leak Alarm
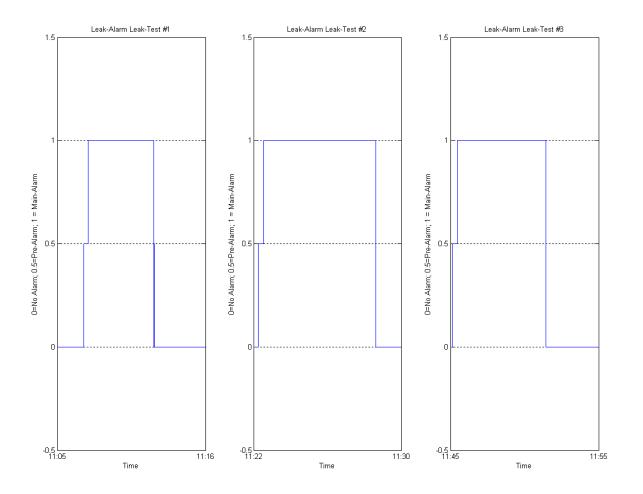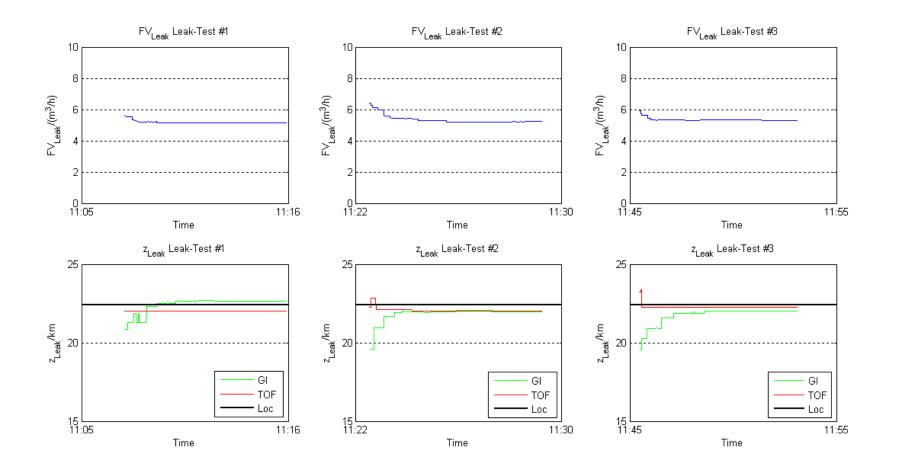
Calculated Leak Parameters
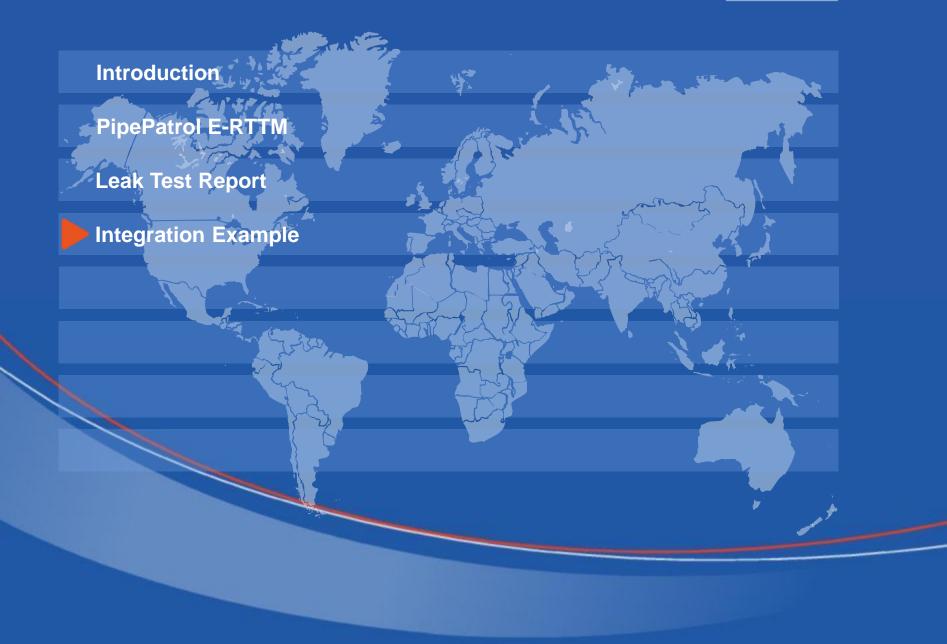
TÜV witnessed Leak Test Results

▶ **Test Results:**

● All Leaks detected within 30s and alarmed within 60s

● Leak localization accuracy for time of flight method   ≤ 1,226 %

● Leak localization accuracy for gradient intersection method   ≤ 1,597 %

Test Number	Leak Pattern Recognized	Leak Alarm	Leak Rate in m3/h	Lost Volume in litres	Leak location TOF	Leak location GI
1	30s	60s	5,15	86	22.145	22.591
2	30s	60s	5,22	87	22.020	21.905
3	30s	60s	5,31	89	22.246	22.005

NATO Pipeline Network, Belgium

General

- The NATO Central Europe Pipeline System is used to deliver fuel for air and ground vehicles around Europe.
- Founded in the late 1950s by NATO, today 3.900mi of pipeline running through Belgium, France, Germany, Luxembourg and the Netherlands
- Since 1959 excess capacity of the pipeline may be used by civilian users.

Belgium
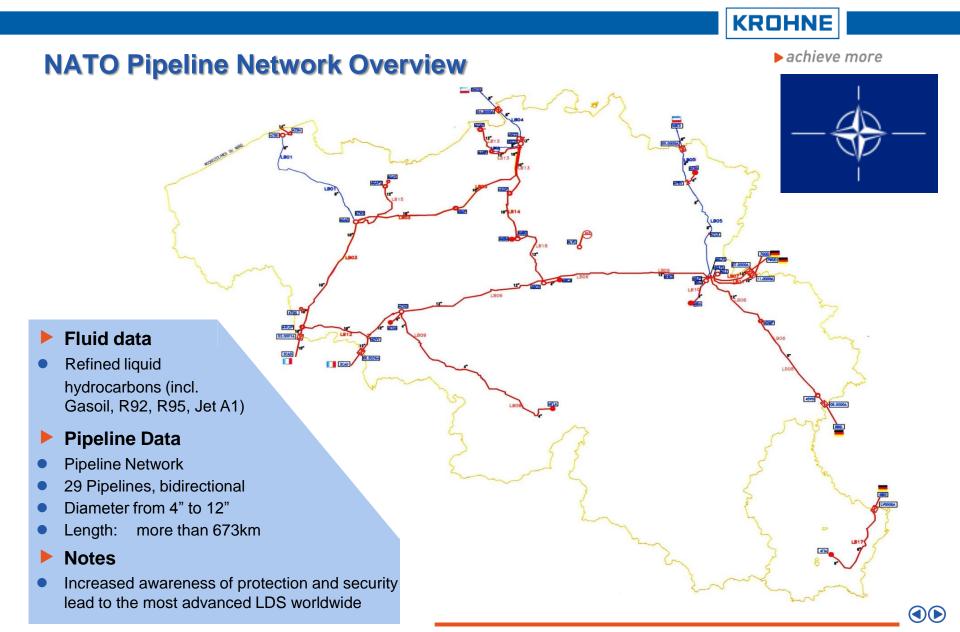
- First country where central pipeline management for NATO Pipeline Network is installed.

Notes

- KROHNE delivered complete solution including: Additional Instrumentation, Flow Computer, Communication Gateways, Data Acquisition Servers, Leak Detection Servers and Operator Stations

NATO Pipeline Network Overview

▶ *achieve more*

Fluid data

- Refined liquid hydrocarbons (incl. Gasoil, R92, R95, Jet A1)

Pipeline Data

- Pipeline Network
- 29 Pipelines, bidirectional
- Diameter from 4" to 12"
- Length: more than 673km

Notes

- Increased awareness of protection and security lead to the most advanced LDS worldwide
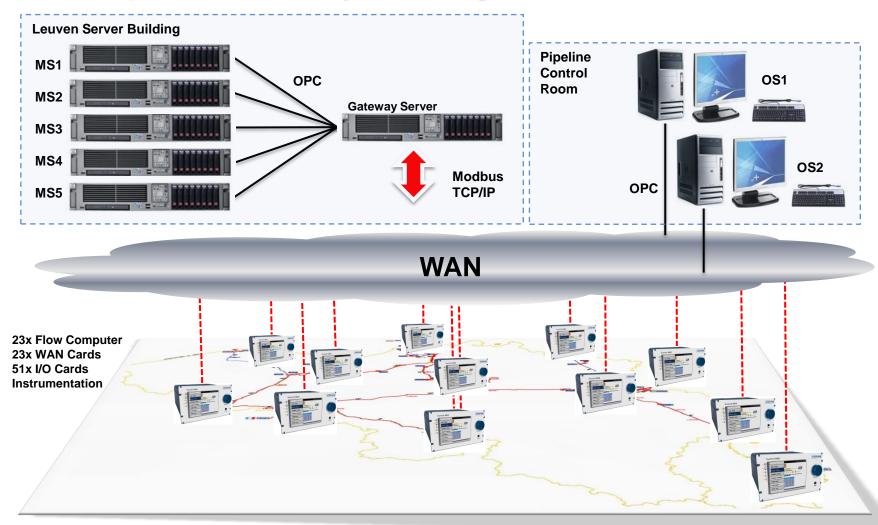
NATO Pipeline Network System Integration
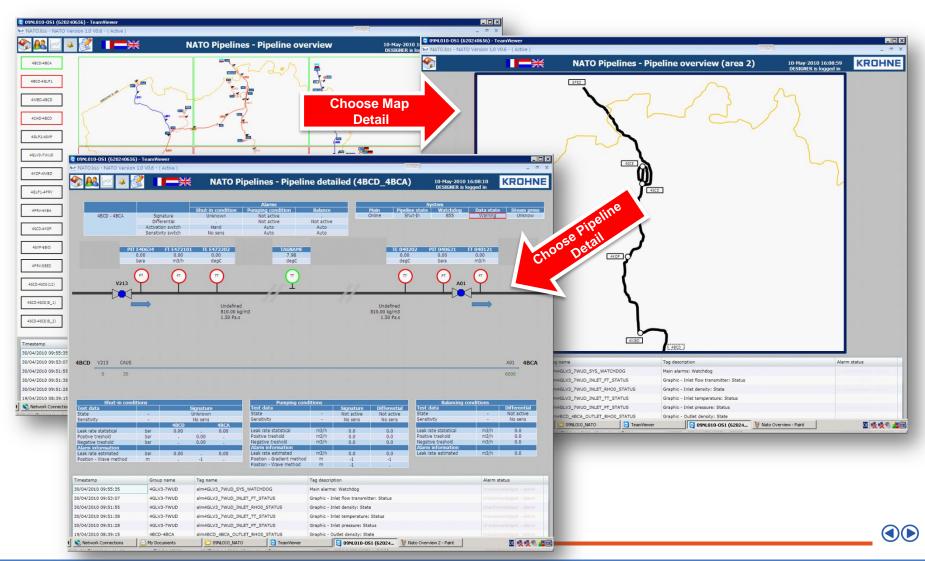
NATO Pipeline Network Interface Overview

Supplementary Modules

▶ **Efficiency Analysis**
- Continuously monitors pipeline efficiency

▶ **Inventory Calculation**
- Provides real pipeline hold up / inventory in real-time based on density profile

▶ **Operator Training**
- Always includes module which plays simulated or recorded field data in real-time
- Can be used for Operator Training through leak test playback

▶ **Instrument Analysis**
- Validates each field measurement and alarms in case of error
- Frozen Point Analysis

▶ **Slack line Monitoring**
- Monitors Pressure Profile for vapor pressure / automatically detects slack line conditions
- Takes elevation profile like mountains and high variations into account

Thank You
for your Attention!

APPENDIX D

HANSACONSULT INGENIEURGESELLSHAFT – TCS "TIGHTNESS CONTROL SYSTEM"

Who we are?
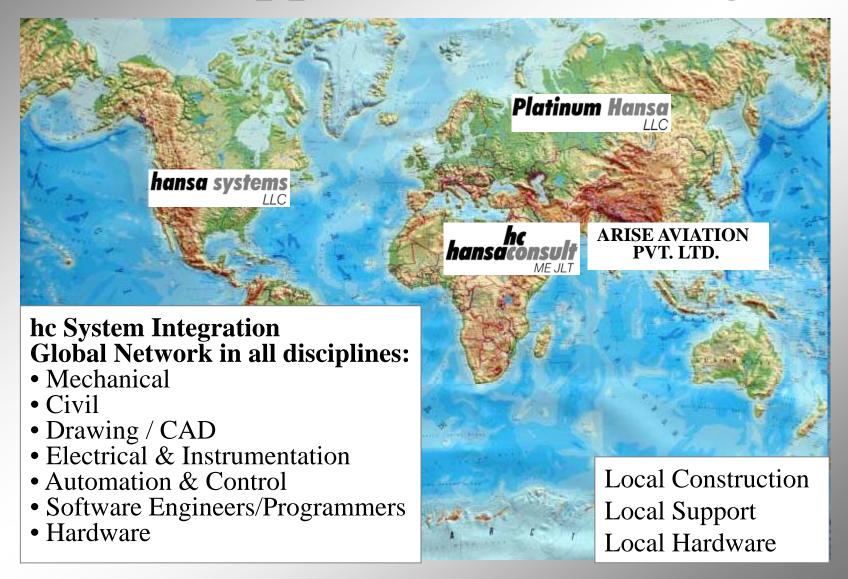
1979: hansaconsult was founded to provide airports, tank farm operators and oil companies with safe and economic fuel infrastructure.

Key products for Tank Farm, Pipeline & Hydrant Systems:

- Engineering & Design

- Automation & Control (SCADA / HMI)

- KLEOPATRA® Simulation Technology for safe, efficient design and analysis

- Experienced staff to perform onsite investigations of economic, operative and technological efficiency studies for facilities

- Tightness Control System **TCS**® providing leak detection solutions for petroleum piping around the world

Certified ISO 9001:2008

IATA Cooperation

hc hansaconsult Ingenieursgesellschaft mbH
Beim Zeugamt 6
D-21509 Glinde
Germany

Attn. Jürgen Grötzbach and Dr. Leszek Juchniewicz

July 26, 2005

Dear Sir,

I am referring to our latest discussion regarding Fuel Consultancy in collaboration with the IATA Airport Consultancy Services and would like to confirm that our mutual scope of co-operation is as follows:

a) Provision of subject matter expertise for the provision of verification and validation "peer review / reality check" relating to airfield fuel distribution and storage facilities, infrastructure, plans, strategies and issues.\
b) Review and recommendation of changes to basic engineering, detailed engineering and layout documents.
c) Recommendations for the Moderinsation / Re-location of Fuelling Infrastructures
d) Provision procurement suppot services associated with the Design, Development and construction of new "low-budget" fuel tank farms (Low Cost Tank Farm Concept) and associated Automation & control Systems incl. Tank Farm Management (Commercial/Technical).

The above mentioned scope would be applied in the following regions:

a) East Europe and CIS states
b) EU Countries
c) GCC Region and Middle East
d) ASEAN States

Looking forward to an interesting co-operation with you.

Ralf Hollman
Manager
Infrastructure Consultancy Services

International Air Transport Association
800 Place Victoria, P.O. Box 113
Montreal, Quebec, Canada H4Z 1M1
Tel.: +1 (514) 874 0202
Fax: +1 (514) 874 9632

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Associated Member of JIG

JIG Joint Inspection Group

PO Box 33094
London W9 2YX
Tel/Fax: 0207 286 4507

October 5, 2010

Hansaconsult Ingenieurgesellschaft mbH
Gutenbergstr. 31
21465 Reinbek
Germany

Attention: Juergen Grotzbach

Dear Juergen

Associate Membership of Joint Inspection Group Limited

I am very pleased to be able to confirm that your application for Hansaconsult to join JIG as an Associate Member has been approved and that Hansaconsult is an Associate Member of JIG with effect from today's date.

History behind TCS® and what is driving it today:

- Developed in 1982 following an incident at Frankfurt Airport

- JIG : Joint Inspection Group

- API / EI 1540

- IATA

- EPA

- Federal, State guidelines

- Company "Best Practices & Protocols"

JIG Guidelines for Aviation Fuel Quality Control and Operating procedures

Change in JIG 10 vs. JIG 9

- Vol. II: Section 3.5.6: All new hydrant systems shall incorporate a means of testing and proving the integrity of the system. Further information concerning pressure testing and tightness integrity (leak detection) is contained in the EI 1540 Recommended Practice, Design, Construction, Operation and Maintenance of Aviation Fuelling Facilities (Annnex E).

API/EI 1540

ANNEX E

GUIDELINES FOR TESTING THE TIGHTNESS INTEGRITY OF AVIATION FUEL HYDRANT SYSTEMS

It is recommended that all new aviation fuel hydrant systems should be fitted with a method to prove the tightness integrity of the system, taking into account:

— hydrant design;
— available technology current at the time of installation;
— national and local regulations and industry codes of practice;
— environmental considerations;
— future airport developments; and
— airport operational constraints.

Existing hydrant systems that use a detailed analysis of pressure measurement are able to detect leaks equivalent to about 0,04 litres/hour/cubic metre at a reference pressure of 7 barg, require a fuel hydrant shutdown period of about one hour and can be used on a regular basis (at least weekly) with minimum disruption to the normal operation of the hydrant.

In general it is considered reasonable to plan for new sections of piping in apron areas to have volumes of up to about 200 cubic metres. For the existing pressure-based systems such a volume would translate into a typical leak detection capability of 8 litres/hour at the reference pressure of 7 barg. For other detection systems, (for example based on acoustics or tracer gas technologies) it will be necessary to establish appropriate section volumes to achieve at least the same detection capability.

It should be recognised, however, that the volume of a section may require to be somewhat increased due to other considerations such as in the case of hydrant feeder lines where a different integrity monitoring method may be more appropriate.

On existing hydrant systems it is recommended that a review be made to identify the most appropriate method of proving tightness integrity or, where a detection system is already installed, if the method is still appropriate. If a system is to be installed in a large existing fuel hydrant some flexibility in determining an appropriate volume for each section may be considered necessary.

Arrangements should be made for the performance capability of a system to be verified on first installation and at regular intervals thereafter (typically at least once per year). The normal method would be to create a series of controlled leaks at different rates and compare these with the output from the detection system.

API/EI1540 – Step by Step

	API/EI 1540 Design, Construction, Operation and Maintenance of Aviation Fuelling Facilities; Annex E: Guidelines for testing the tightness integrity of aviation fuel hydrant systems	TCS® Com-pliance	Comments
1	Suitable for hydrant design	Y	
2	Current available technology	Y	
3	Meeting national and local regulations (if applicable)	Y	
4	Industry code of practice	Y	
5	Taking into account environmental considerations	Y	
6	Flexible to future airport development	Y	
7	Flexible to airport operational constraints	Y	
8	Sensitivity of 0.04 litres/hour/cubic metre at a reference pressure of 7 bar for pressure based system	Y	
9	Measuring period of about an hour	Y	45 minutes
10	Availability to be used on a regular basis (at least weekly)	Y	
11	Minimum disruption to the normal hydrant operation	Y	
12	Section volume usually about 200 cubic metres corresponding to leak detection capability of 8 litres per hour at a reference pressure of 7 bar (Flexibility due to other considerations, such as feeder line or installation in large existing fuel hydrant)	Y	TCS® Engineering Standard considered with section sizing
13	Performance capability verification on first installation with series of controlled leaks at different rates and comparison of result calculated/measured output	Y	TCS® Commissioning Standard
14	Regular performance capability verification (typically at least one per year) with series of controlled leaks at different rates and comparison of result calculated/measured output	Y	TCS® Maintenance Contract

TCS® Tightness Control System

	TCS® Pressure Step	TCS® Pressure Temperature	TCS® Kleopatra
Leak Detection	Yes	Yes	Yes
Leak Location	by section	by section	Yes
API/EI1540	Full compliance	Partially compliant	
Sensitivity	0.04 liters / hour / m^3 section volume	up to 4 l/h	
Frequency of tests (typical application)	Daily control to detect small leaks	Annual test to confirm PS results	Continuous dynamic monitoring e.g. rupture
Limitation on size of hydrant system	No	No	No
Influence of air	Regular ventilation to avoid changing detection accuracy	Regular ventilation to avoid changing detection accuracy	Regular ventilation to avoid changing detection accuracy
Influence of water (typical quantities)	No	No	No
Influence of temperature	Compensation of influence	Temperature transmitter installed	Self-learning system
Installation	Permanent or mobile application	Permanent	Permanent

TCS® Pressure Temperature

- Pipeline section to be tightly closed.
- Measurement of pressure and temperature
- Number of temperature transmitters/probes increases with length of pipeline.
- Physical relation between temperature gradient and pressure gradient of the medium
- Leakage causes a pressure variation.
- Detection by comparison of the pressure variation with the temperature variation.
- Accuracy: up to 4 l/h leakage rate
  depending on the test time
  independent from size of the pipeline section.

TCS® Pressure Step Method

Phase 1:
- Raising of pressure to high test level by using main system pumps or permanent / mobile skid unit
- 10 minute settling time
- 2 minute measuring period
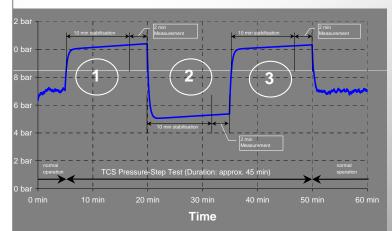
Phase 2:
- Reduction of pressure to low level by opening a pressure relief / bypass valve
- 10 minute settling time
- 2 minute measuring time

Phase 3:
Same as Phase 1
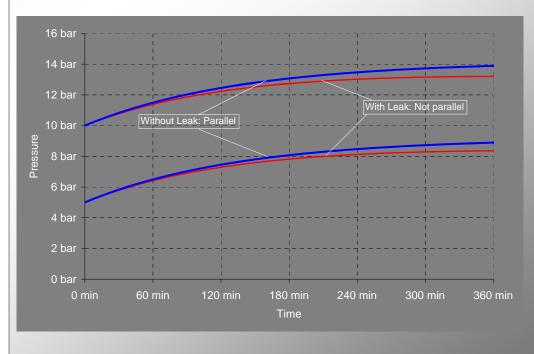
Data Evaluation

TCS® Pressure Step – The Evaluation

- Comparison of the three pressure curves and calculation of the tightness factor.

- Leakage: Higher pressure results in a higher leak rate. The pressure curves are not parallel.

- Since the leak rate depends on test pressure, influence of temperature changes can be compensated.

- The system is indicated as tight if the tightness factor is not higher than the upper limit of 0.04 l/(h*m3) or 0.004% of line volume.

- A report is printed for documentation and data stored for future reference.

TCS® Tightness Control System – Control Philosophy
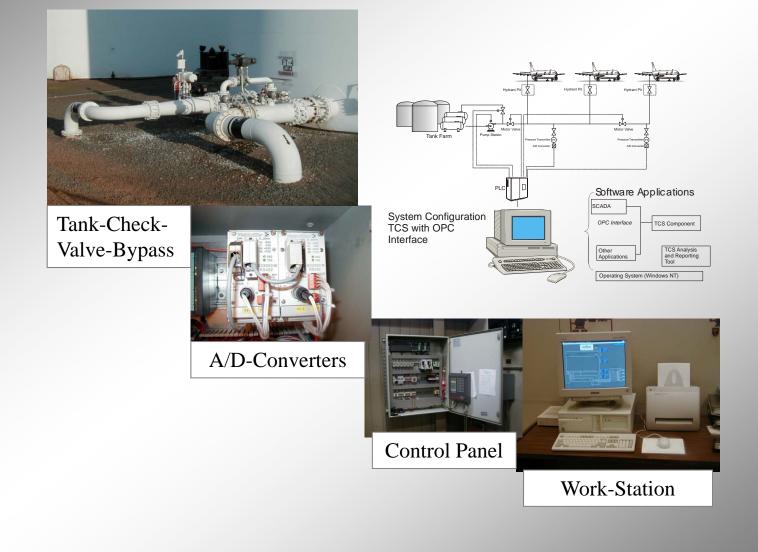
- TCS® Software is the heart of the Leak Detection.

- TCS® Software is installed on the SCADA Server / TCS® PC

- TCS® defines and controls the pressure cycles.

- Control System controls automated valves, if installed for TCS®.

- All signals are exchanged via OPC server.

- Tank Farm PLC may be used to open / close valves or start pumps on TCS® commands.

TCS® - System Layout

Tank-Check-Valve-Bypass

A/D-Converters

Control Panel

Work-Station

System Configuration TCS with OPC Interface
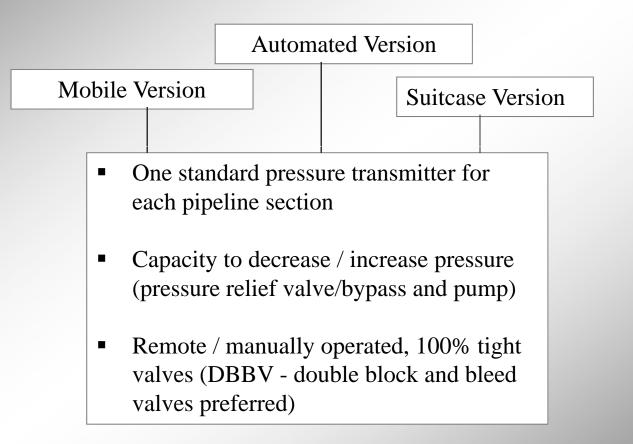
General Requirements TCS®

Automated Version

Mobile Version

Suitcase Version

- One standard pressure transmitter for each pipeline section

- Capacity to decrease / increase pressure (pressure relief valve/bypass and pump)

- Remote / manually operated, 100% tight valves (DBBV - double block and bleed valves preferred)

Tightness Control
Mobile Solutions

- The System is mounted on a trailer
- Fully self-contained
- On-board independent power supply
- The test is run automatically.
- The system controls the skid
  mounted pump and valves.

Application Services

- Access to remote services including evaluation of data

- Continuous research and development to optimize accuracy, reduce testing time

- Software Updates

- User Hotline and Helpdesk

- Contracted reaction times

- System recalibration in case of changes of section size

- System adjustment for extension of hydrant system or closure of sections

- Regular performance capability verification according to API/EI1540: at least once a year including simulated leak tests (whole system/randomly selected sections)

- Tightness Control Seminars and User group meetings to provide a forum for dynamic exchange of ideas and experience, training & consulting

Check your system

Check your system

Leak test to prove the accuracy of the system 0.04 litres/hour/cubic metre with a simulated leak by an orifice of defined size

- TCS® System Commissioning according to API/EI 1540, certified according to ISO9001:2008

- Regular TCS® System-Recertification

- Verification of accuracy of installed system

¼ '' NPT thread

Hose adapter

Check your system

PIPELINE CHARACTERISTIC	PIPELINE CONFIGURATIONS					
	A	B	C	D	E	F
Location	North Slope	North Slope	North Slope	North Slope	Cook Inlet	Cook Inlet
Type	Transmission	Transmission	Flowline	Flowline	Transmission	Flowline
Total Length (miles)	40	25	4	8	40	9
Length Aboveground (miles)	40	24	4	2.5	0	0.5
Length Underground (miles)	0	1	0	0	40	0
Length Subsea (miles)	0	0	0	5.5	0	8.5
Diameter (inches)	24	12	28	12/16 pipe-n-pipe	20	8
Daily Production						
Crude Oil [barrels per day (bpd)]	150,000	1,400	10,000	15,000	23,000	3,000
Produced Water (bpd)	0	0	125,000	15,000	0	4,000
Natural Gas (million standard cubic feet of gas)	0	0	250	20	0	600
Typical Input and Output Parameters Measured						
Flow (bopd)	150,000	1,400	10,000	15,000	23,000	3,000
Pressure [pounds per square inch (psi)]	1200 to 1800	125 to 1400	100 to 600	100 to 600	100 to 125	100 to 600
Temperature [degrees Fahrenheit (^{o}F)]	100 to 180	100 to 180	90 to 110	90 to 120	100 to 140	90 to 110
Insulation Thickness (inches)	2.5	2	3	3	0	0
Ambient Air Temperature Range (^{o}F)	-62 to 83	-62 to 83	-62 to 83	-62 to 83	-38 to 82	-38 to 82
Pipeline Volume (gallons)	4,412,314	766,487	675,629	245,276	3,042,648	126,256
1% Nominal Daily Throughput (gallons)	63,000	588	4,200	6,800	9,660	1,260
1% Nominal Daily Throughput (gallons per/hour)	2,625	24.5	175	283	402.5	52.5
TCS Detectable Leak Rate (gallons per/hour)	?	?	?	9.81	?	5.05
TCS Pressure – Step Application	Possible	Possible	Possible	Yes *	Possible	Yes*
TCS Kleopatra Application	Yes	Yes	Yes	Yes	Yes	Yes
Comments	Volume / Infrastructure / Pressure	Infrastructure / Low Throughput	Frequency / Infrastructure / Air Removal	Frequency / Infrastructure / * Air Removal	Infrastructure / Volume	Infrastructure / Frequency / * Air Removal

Athens Int Airport

NEW ATHENS INTERNATIONAL AIRPORT
HYDRANT REFUELLING SYSTEM SIMULATOR

Tightness Control System TCS®

From Engineering & Design

To Reality

Capacity: 4 tanks / each 6.000 m³

Airbus A380 Fuel Farm

Tank Farm
- Design & Engineering
- Evaluation of different tank farm configurations
- Assistance for Official Approval
- Co-ordination of construction works, site supervision
- Programming of Automation and Visualization
- Fire Fighting System
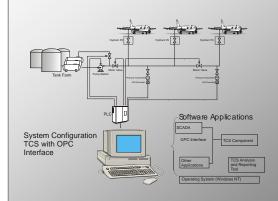
Hydrant System
- Design & Engineering
- Dimensioning of the hydraulic system
- Pressure shock calculations and simulation
- Programming of Automation and Visualization
- Tightness Control System TCS®

Administrative Automation
- Inventory Management System

Airports S-Africa

Johannesburg O.R. Tambo Int Airport
Hydrant System
- Dynamic Simulator Kleopatra®
  Hydraulic Modelling: Integration real-time
  operations into a virtual-self educating system
  New level of systems integrity and safety
- Tightness Control System TCS®
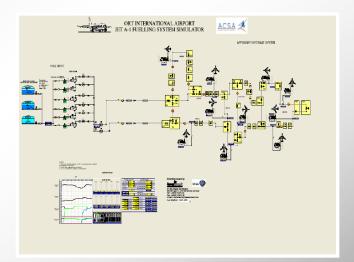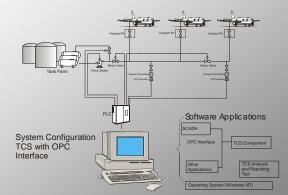
Cape Town Int Airport
Hydrant System
- Hydraulic Simulation Study Kleopatra®
- Tightness Control System TCS®

Durban King Shaka Int Airport
Hydrant System
- Hydraulic Simulation Study Kleopatra®
- Tightness Control System TCS®

Where are we?

- London, Frankfurt, Munich, Athens, Amsterdam, Stockholm, Cairo, Johannesburg, Cape Town, Dubai, Doha, Seoul, Singapore, Perth, Cleveland, Detroit, Anchorage…

hansaconsult – global fuel systems competence
to meet local targets

APPENDIX E

TELVENT USA CORPORATION - SIMSUITE PIPELINE

Smart Information for a Sustainable World

Telvent Leak Detection Methodologies and Strategies

for the Successful Implementation of Model Based Leak Detection Systems

September, 2011

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Agenda

SimSuite Pipeline:
Advanced Pipeline Simulation

- **Telvent Leak Detection**
- **SimSuite Leak Detection**
  - ▶ High Fidelity RTTM
- **Model Based Pipeline Applications**
- **SSPL Model Features**
- **Case Studies & Pilot Projects**
- **Samples Displays**
- **Conclusions**

Telvent Leak Detection Solutions

- **SimSuite (RTTM)**
- **PLM (Modified Volume Balance)**
- **Pressmon (Pressure Flow Rate Monitoring)**
- **Other**
  - **Rate of Change**
  - **Bracketing or Clamping a Pipeline**
  - **Pressure / Temperature Trends on Shut in Lines**

Smart Information for a Sustainable World

SimSuite
Leak Detection
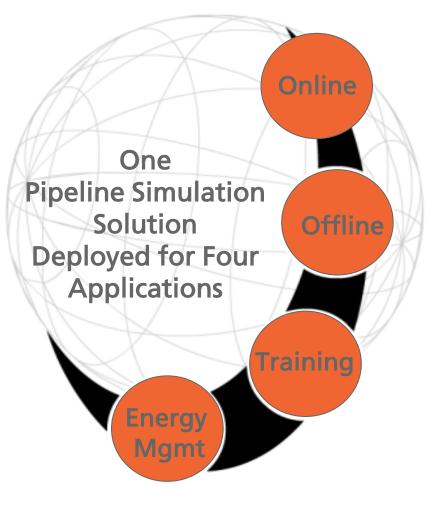
Real Time Transient Model
Compensated Mass Balance Method

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Electric

What is SimSuite Pipeline?

- **High Fidelity Hydraulic Model**
  - **Steady and transient state**
  - **Gas, liquid, slack, & two-phase**
  - **Handles full range of products**
  - **Excellent temperature tracking**
  - **Handles complicated flow configurations**
  - **Detailed transient response**

One
Pipeline Simulation
Solution
Deployed for Four
Applications

Online

Offline

Training

Energy
Mgmt

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TELVENT
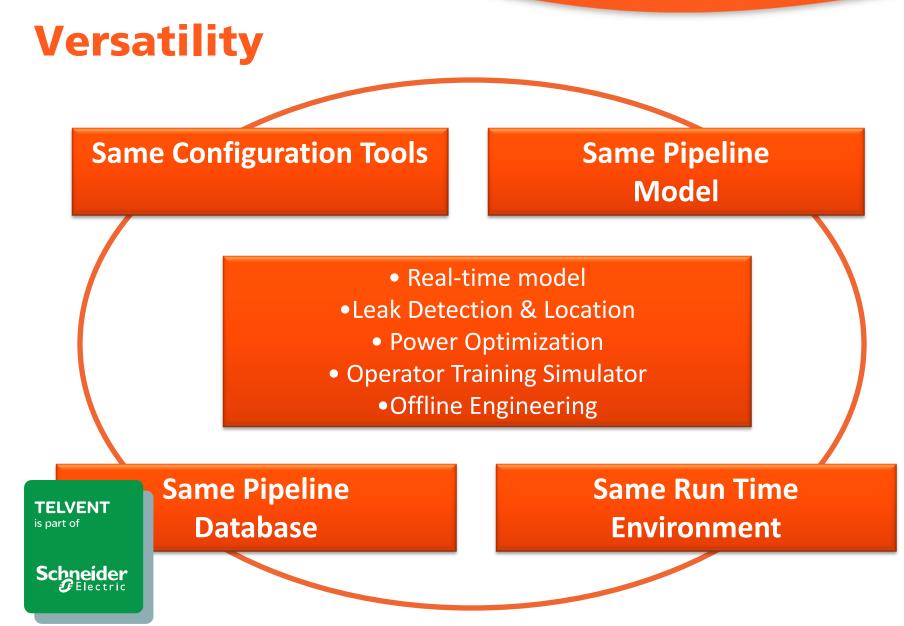
What is SimSuite Pipeline used for?

- **On-line computational pipeline modeling**
  - Leak detection
  - Batch/Composition tracking and/or scraper tracking
  - Inventory management and survival analysis
  - Look ahead analysis and predictive modeling

- **Off-line engineering & design analysis**
  - Pipeline design
  - Steady state and transient analysis

- **Pipeline operator training & qualification**
  - Generic & "full scope" implementations

- **Energy Management – Power Optimization**
  - Energy consumption and cost analysis

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Transient Model

"It's the Linepack, Stupid"

- **Hi-Fidelity Simulation based on detailed Equations for:**

  Momentum Balance Equation

  - Momentum Conservation
  - Mass Conservation
  - Energy Conservation

$$\frac{dF_f}{dt} = -\frac{\alpha_f * A}{K_u} * \left(\frac{dP}{dZ} + f_{f\text{-}w} + f_{f\text{-}f} + K_u * \rho_f * \vec{g} - \delta * P_{pump} \right)$$

$$+ \sum \delta * S_f * \vec{v}_{src}$$

A detailed accounting of the movement of mass and associated energy transfers inside the pipeline.

$$\frac{\partial A * (\alpha * \rho * h * F)_f}{\partial t} = \frac{\partial (h * F)_f}{\partial Z} - \sum S_f * h_{src}$$

$$+ A * (\Gamma * h_{sat} + Q - W)_f$$

Energy Conservation

Mass Conservation

$$\frac{\partial A(\alpha * \rho)_n}{\partial t} + \frac{\partial F_n}{\partial Z} = \sum \frac{\partial F_{bn}}{\partial Z} + \frac{\partial \Gamma_n}{\partial Z}$$

Important Transient Model Features

- ✓ **2-Phase flow**
- ✓ **Slack Conditions**
- ✓ **Product/Batch/Composition/Pig Tracking**
  - ✓ Blending, Batching, Both
- ✓ **Drag Reducing Agents (DRA)**
- ✓ **Non-Newtonian Flow**
- ✓ **Multiple Friction Factor Equations**
- ✓ **Accurate Thermal Model**
- ✓ **Pipeline Inventory – Pipe, Tank Farms and Station Equipment & Piping**
- ✓ **Over/Under Pressure Calculation and Alarming**
- ✓ **Fast Execution**
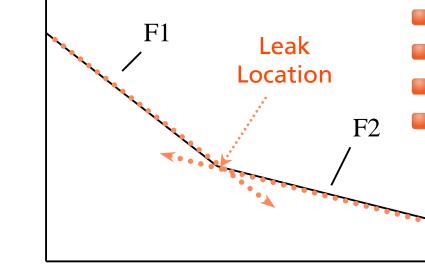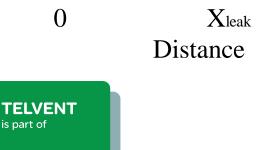
Leak Location
Gradient Intersection Method

F1

Leak
Location

F2

H
e
a
d

0   X_{leak}   X_2

Distance

- "0" is Upsteam Pres. Meas.
- "X2" is DownStream Pres. Meas.
- "F1" Rate of Pres. Drop Upstream
- "F2" Rate of Pres. Drop Downsteam

Accuracy depends on all factors; Instrumentation, scan rates, steady state, product location

- **Can be missed entirely**
- **Location accuracy continues to improve as leak develops**

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SimSuite Advantage

- **One Model, Multiple Applications**
  - **Common configuration tools**
  - **Lower maintenance cost, higher product value**
  - **Our competitors have different models for different applications**
- **SimSuite Pipeline**
  - **Proven superior performance in several pilot projects: CPPL, Colonial, Pembina…**
    - **Significantly reduced false alarm indications results in <u>trust in the system</u> & better response**

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Its Proven!

- **Our Leak Detection Success is very real**
  - **Telvent has implemented many successful solutions and effective LD systems**
    - **No. 1 in liquid systems in NA**
- **It is Not Magic, it is a deliberate science**
  - **Theories are complex, reality even more so**
- **The Successful Integrated Solution**
  - **Identify Needs, Solution & Partner**
  - **Plan, Implement, and Maintain.**

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Case Studies & Pilot Projects

SimSuite consistently wins head-to-head competitions against competitors with live leak tests

- **Pembina Pipeline:**
  - **Large Pipelines**
  - **NGL, Crude, Products**
  - **Replaced incumbent**

- **Colonial Pipeline:**
  - **lasted 2 years:**
  - **Selected SimSuite Pipeline**

- **ConocoPhillips**
  - **HCA Pipelines**
  - **Replaced Incumbent**
  - **Added Trainer**

- **Customer Reference List**
  (available on request)

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14

Marathon-Ashland Oil Company

Complex network of 60+ pipelines and 24 tank farms

- Crude oil, products, liquid NGL (propane, butane etc.), liquid condensate and LPGs

  - 266 different products

Leak Detection Results:

- Long-term thresholds - **5-times lower than required**

- Detection times - **12-times faster than required**

- Successful physical leak-detection tests
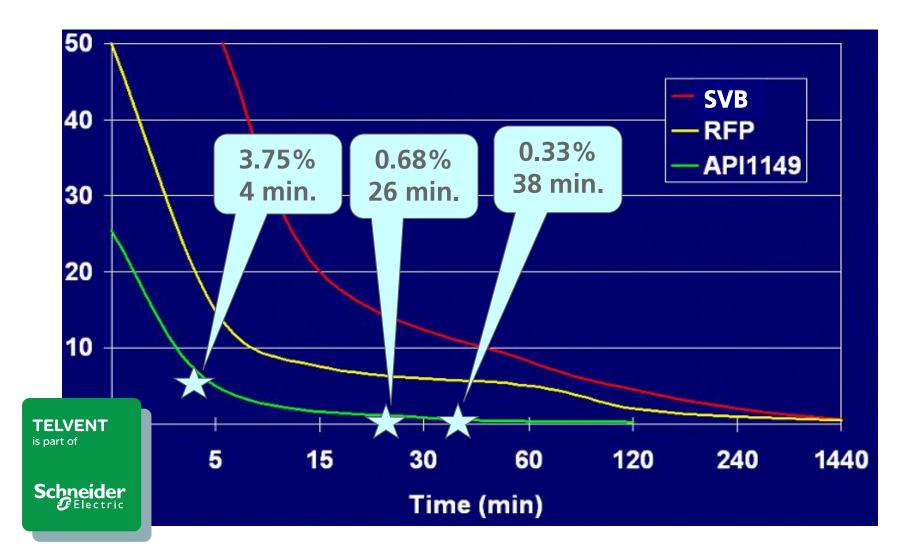
  - **Marathon engineers configured all pipelines and tank farms themselves except for 2 pipelines**
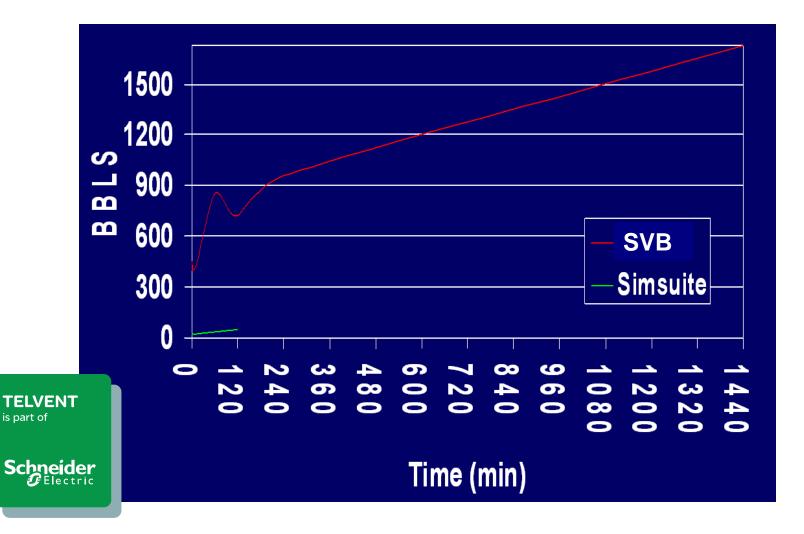
Marathon Leak Test Results

Caspian Pipeline Performance

- **Actual Results from real world LDS test.**
  - **Product was released using a hand-operated valve to redirect product to a tanker truck.**
- **Desired flow rate reached some time after initiation of transient.**

- **Flow rates and volumes for the crude removed at test locations**
  - **estimated based on valve open and close times and volume of crude in the tank at conclusion of test.**
- **Results tabulated for three tests at each of three separate locations**

Early February 2004 an illegal tap with a peak leak flow rate of 25-30m³/hr was detected by the Telvent Leak Detection system. The location of the leak was identified within 10km of the actual tap.

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Caspian Pipeline Performance

107 km section	TEST #1	TEST #2	TEST #3
Estimated average leak flow rate (m³/hr)	263	117	81
Peak leak flow rate – model (m³/hr)	282	114.16	104.8
Detection time (mm:ss)	0:39	3:55	4:49
Estimated volume (m³)	2.8	7.6	6.5
96 km section	TEST #1	TEST #2	TEST #3
Estimated average leak flow rate (m3/hr)	150	90.7	82
Peak leak flow rate – model (m3/hr)	173.54	136.27	71.3
Detection time (mm:ss)	0:58	1:34	5:37
Estimated volume (m3)	2.4	2.4	7.7
203 km section	TEST #1	TEST #2	TEST #3
Estimated average leak flow rate (m3/hr)	273.1	175.8	75
Peak leak flow rate – model (m3/hr)	199.2	204.8	134.13
Detection time (mm:ss)	2:01**	2:26	5:17
Estimated volume (m3)	9.2	7.1	6.6

**Note: This section was missing pressure transmitters, thus affecting detection time

Smart Information for a Sustainable World

SimSuite Displays
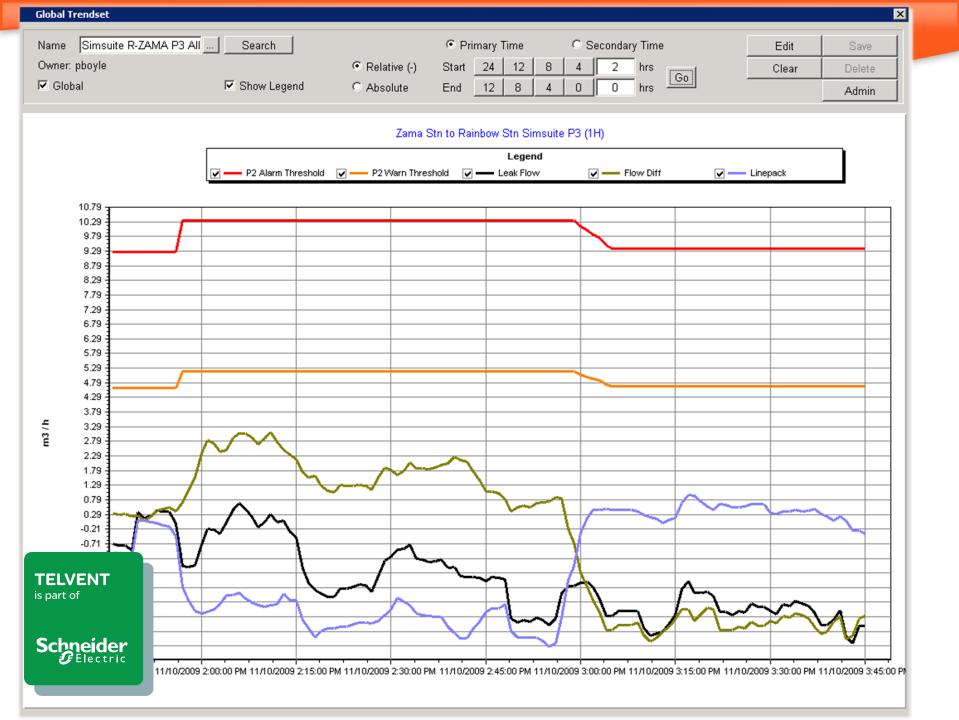
Same HMI as Telvent SCADA
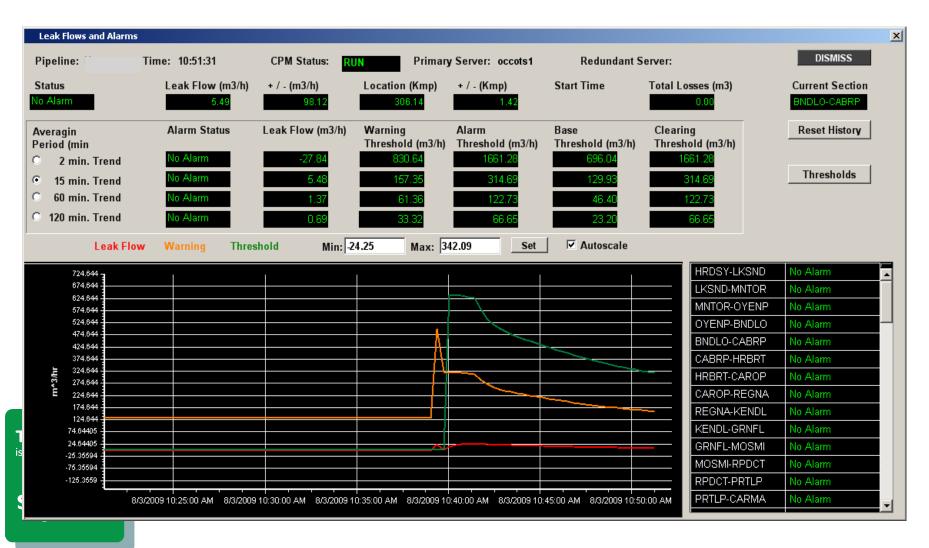
Hydraulic Profile

TELVENT

Alarm Profile
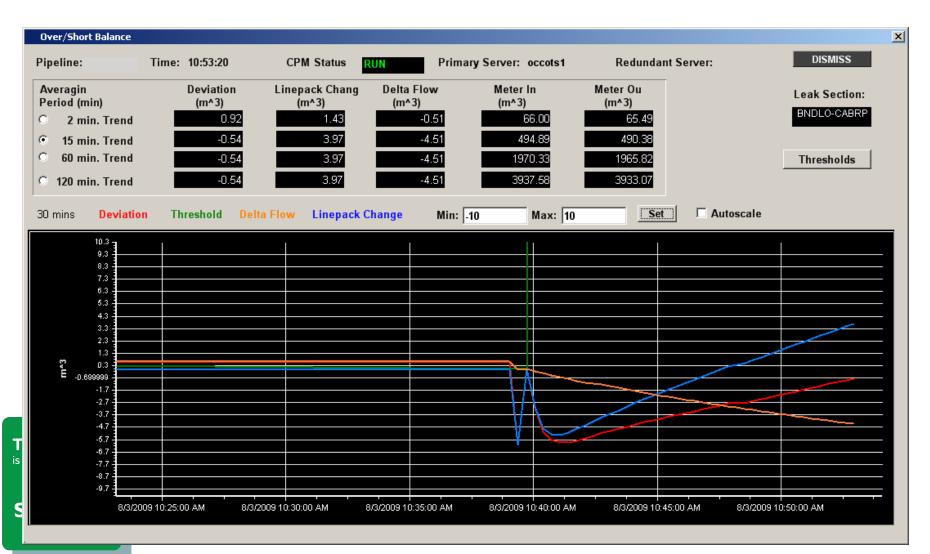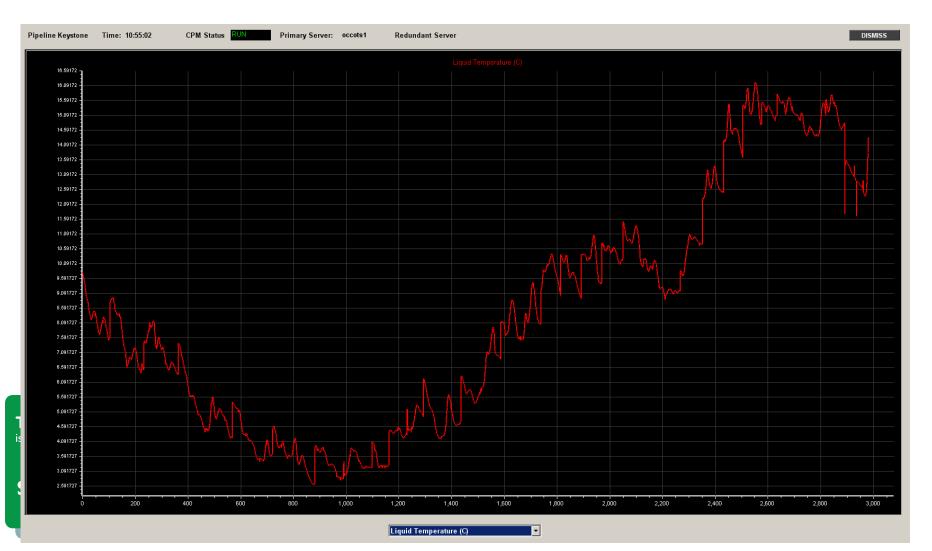
Over/Short Display

Temperature Profile

Alarm Displays

Leak Warning

09/16/2004 11:49:52.3	CPM_Warning: RBLI Overall CPM ALARM
09/16/2004 11:49:52.3	CPM_Warning: RBLI Leak ALARM
09/16/2004 11:35:33.0	Neither SIMSUITE service is hot, sspdnademo wil

Leak Alarm

09/16/2004 11:50:38.0	CPM_ALARM: RBLI Overall CPM ALARM
09/16/2004 11:50:38.0	CPM_ALARM: RBLI Leak ALARM

Alarm Summary

Alarm Summary

Alarm

Filters

View Areas: 0area

Remote		
Remote:		

Conditions:

in alarm	not in alarm	both
unacknowledged	acknowledged	both

Page Acknowledge

Alarm Disturbance

On/Off   No record

Page

Time	Description	Comment	
09/16/2004 11:50:38.0	CPM_ALARM: RBLI Overall CPM ALARM		
09/16/2004 11:50:38.0	CPM_ALARM: RBLI Leak ALARM		
09/16/2004 11:35:33.0	Neither SIMSUITE service is hot, sspdnademo will		

Controller/Operator Actions and Procedures

- **response to leak alarms should follow documented work practices in guidance or training material including:**
  - Expected leak detection performance per pipe segment
  - Verification Steps
  - Time allowed prior to shutdown
- **If procedures call for additional contact with others before action, ensure contact is always promptly available for consultation and escalation.**
    - **During certain operational modes alarms may be suppressed or thresholds modified**
    - **Controllers need to know the triggers that modify thresholds**
      - Pump Start *

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A Good Catch...

Actual Pipeline incident:

- Lost a gasket on the discharge MOV at a pump station

LDS Performance

- Model identified and alarmed <u>a 5 barrel leak within 14 seconds</u>

Operational actions & results

- Pipeline personnel dispatched to the field immediately based on the location of the leak models as calculated by the LDS
- Pipeline Controllers shut down operations within 5 minutes
  - State Fire Marshall, Fish and Game notified per procedure
  - State Fire Marshall notified Dept. of Transportation
  - Total loss minimized to 125 barrels contained within concrete vault
  - Clean up and normal operation restored in 11 hours

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Summary and Conclusions

- **Simply owning and using a CPM leak detection system is not sufficient to comply with relevant regulations.**
  - Pipeline operators must continually review the operational procedures in use and the way controllers interact with the tools provided
  - Updated information must be effectively communicated to controllers.
    - » Providing Adequate Information; MOC - CFR 49 192.631, 195.446
    - » Refresher training on an annual basis with lessons learned

Summary and Conclusions

- **No single leak detection solution may be optimum for the diverse range of pipelines in differing regions that an operator is responsible for**
  - **A multi-tiered approach - recommended practice**
    - **choices need to be balanced with available and committed resources**
      - After implementation, field crews will likely be impacted by a need for more instrument maintenance
  - **Controllers need to know the expected performance of detection system**
    - **Followed by verification and response**

APPENDIX F

MH CONSULTING - *SELECTING A PLD FOR CRUDE OIL TRANSMISSION PIPELINE WITH TEMPERATURE VARIATIONS AS PRODUCT IS CONVEYED DOWNSTREAM*
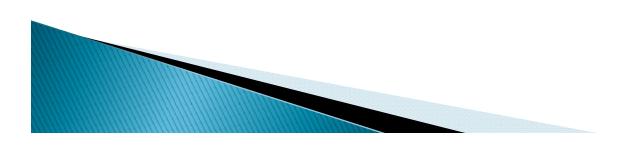
Thermal Effects that Impact Selection of a Crude Oil PLD System

Morgan Henrie PhD, PMP
Ed Nicholas
Philip Carpenter

2011 Pipeline Leak Detection Technology Conference
Anchorage Alaska
September 13-14, 2011

Why Consider Thermal Effects When Considering Leak Detection Systems?

1. To understand or predict the impacts on leak sensitivity thresholds

2. To assist in selecting a leak detection system for that unique pipeline

API-1149 Reference
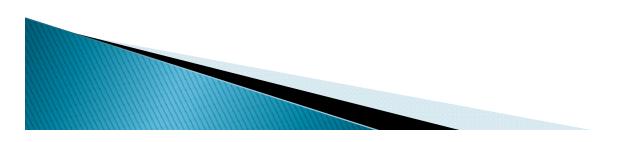
▸ The final outcome... is often determined by a number of independent and direct measurements, each of which has its own uncertainty

▸ Pipe line fill factors of uncertainty include
  ◦ Relative Density
  ◦ Temperature
  ◦ Diameter
  ◦ Length
  ◦ Pressure
  ◦ Wall thickness
  ◦ Young's modulus

API-1149 Reference

- The final outcome… is often determined by a number of independent and direct measurements, each of which has its own uncertainty

- Pipe line fill factors of uncertainty include
  - Relative Density
  - Temperature
  - Diameter
  - Length
  - Pressure
  - Wall thickness
  - Young's modulus

How do external thermal effects impact leak sensitivity and uncertainty?
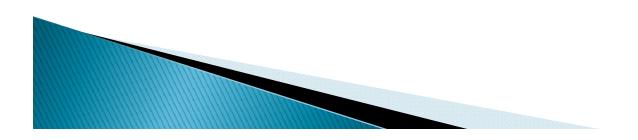
1. Ambient and ground temperatures directly influence thermal expansion of the fluid
2. Crude oil coefficient of thermal expansion, with an API of 33, is about 1 / (2000 deg F) or 0.0005 [deg F]
3. A temperature change of 1°F causes pipeline inventory to change by 0.05% (increase or decrease)

When is incorporation of temperature in the LD system important?

- It depends>>>>>>>>>
  ◦ Pipeline physical environment
  ◦ Pipeline construction
  ◦ Operating environment
  ◦ Leak detection requirements

- Remember each pipeline is unique when all aspects are considered

Core Questions To Assist In The Determination Process

1. What is the desired sensitivity and speed of response of the leak detection system?

Are your requirements
- The lowest (smallest) leak threshold possible
- Leak detection as fast as possible
- Lowest number of non-leak alarms
- A combination of all

Or some other criteria?

Core Questions – Continued

2. How will thermal effects impact the sensitivity and speed of response of the leak detection system on your pipeline?

3. How much will other (non-thermal) uncertainties limit the sensitivity of the leak detection system?

Impact of Temperature Uncertainty

▸ An uncertainty in the rate of change of pipeline temperature results in an uncertainty in the rate of change of pipeline inventory (packing rate uncertainty)

$$Packing\ Rate\ Uncertainty = Pipeline\ Volume \cdot C_T \cdot U_T$$

$$\frac{Packing\ Rate\ Uncertainty}{Flow\ Rate} = \frac{Pipeline\ Volume \cdot C_T \cdot U_T}{Flow\ Rate} = t_{Transit} \cdot C_T \cdot U_T$$

where

C_T: The coefficient of thermal expansion

U_T: Uncertainty in rate of change of average temperature (°F/hr)

$t_{Transit}$: Transit time (hours) through the pipeline (or pipeline segment of interest) $= \dfrac{Pipeline\ Volume}{Flow\ Rate}$

Impact of Temperature Uncertainty

▸ The packing rate uncertainty limits the sensitivity of pipeline leak detection

$$\frac{Packing\ Rate\ Uncertainty}{Flow\ Rate} = t_{Transit} \cdot C_T \cdot U_T$$

Therefore, the minimum leak detection sensitivity due to Thermal uncertainties, expressed as a % of flow rate is:
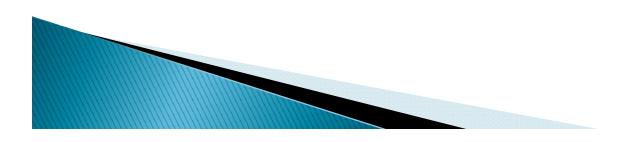
$$Minimum\ LD\ Threshold[\%] = 100 \cdot t_{Transit} \cdot C_T \cdot U_T$$

Temperature Uncertainty Example

Minimum LD Threshold = $100 \cdot C_t \cdot U_t \cdot t_{transit} [\%]$

	Minimum LD Threshold			
Transit Time (hr)	U_t = Thermal Uncertainty [°F/hr]			
	0.1	0.5	1	2
12	0.1%	0.3%	0.6%	1.2%
48	0.2%	1.2%	2.4%	4.8%
96	0.5%	2.4%	4.8%	9.6%

PIPELINE CHARACTERISTIC	PIPELINE CONFIGURATIONS					
	A	B	C	D	E	F
Location	North Slope	North Slope	North Slope	North Slope	Cook Inlet	Cook Inlet
Type	Transmission	Transmission	Flowline	Flowline	Transmission	Flowline
Total Length (miles)	40	25	4	8	40	9
Length Aboveground (miles)	40	24	4	2.5	0	0.5
Length Underground (miles)	0	1	0	0	40	0
Length Subsea (miles)	0	0	0	5.5	0	8.5
Diameter (inches)	24	12	28	12/16 pipe–n–pipe	20	8
Daily Production						
Crude Oil [barrels per day (bpd)]	150,000	1,400	10,000	15,000	23,000	3,000
Produced Water (bpd)	0	0	125,000	15,000	0	4,000
Natural Gas (million standard cubic feet of gas)	0	0	250	20	0	600
Typical Input and Output Parameters Measured						
Flow (bopd)	150,000	1,400	10,000	15,000	23,000	3,000
Pressure [pounds per square inch (psi)]	1200 to 1800	125 to 1400	100 to 600	100 to 600	100 to 125	100 to 600
Temperature [degrees Fahrenheit (ºF)]	100 to 180	100 to 180	90 to 110	90 to 120	100 to 140	90 to 110
Insulation Thickness (inches)	2.5	2	3	3	0	0
Ambient Air Temperature Range (ºF)	−62 to 83	−62 to 83	−62 to 83	−62 to 83	−38 to 82	−38 to 82

Sample Theoretical Thermal Influences

Length (miles)	Pipe OD (ft)	Insulation (fiber glass)	Throughput (bpd)	Ambient Temp (F)	Inlet Temp. (F)	Outlet Temp. (F)
40	2	2 Inches	150,000	-20	103	94.7
40	2	2 Inches	150,000	-40	103	93.2
40	2	2 inches	100,000	-40	103	88.5
25	1	2 inches	1,400	-20	103	-9.1
25	1	2 inches	1,400	-40	103	-27.3

Pipe Length (miles)	Throughput (bpd)	Transit Time (hr)	Minimum LD Threshold Due to Thermal Uncertainty (°F/hr)			
			0.1	0.5	1	2
40	150,000	1.824	0.091%	0.456%	0.912%	1.824%
40	100,000	27.12	0.137%	0.672%	1.368%	2.64%
25	1,400	292.8	1.464%	7.44%	14.64%	28.8%

Wrap Up

- Temperature affects pipe line fill
- Temperature measurement uncertainty can become a limiting factor to leak detection
- Each pipeline is unique
- Need to clearly identify
  - Leak detection requirements
  - Perform a series of steps that evaluates how the various factors will contribute to the overall sum of uncertainties and subsequent leak detection system capabilities

APPENDIX G
AREVA NP GMBH - LEOS

LEOS

UL 61010B
Certificate No.
U8 08 02 64760 001

LEOS®
Leak Detection in Arctic Environment

Dr. Walter Knoblach, *AREVA NP GmbH, Erlangen / Germany*
Peter Bryce P. Eng., *Brytech Consulting Inc., Vancouver / Canada*

AREVA

Contents

Motivation:
Why detect low threshold oil leaks?

leak rate

in particular difficult
for multi-phase flow!

0.5 - 1%
(typ.)

factor 1000

pollution / damage

LEOS detection 1 l/h

conventional
mass flow
detection

time
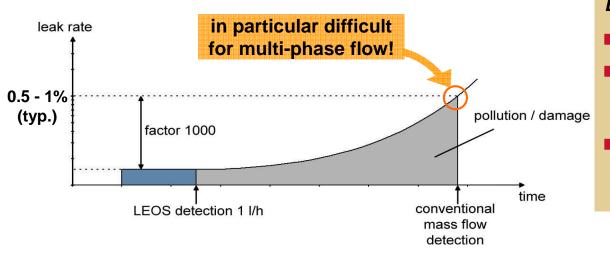
Example Prudhoe Bay March 2006:
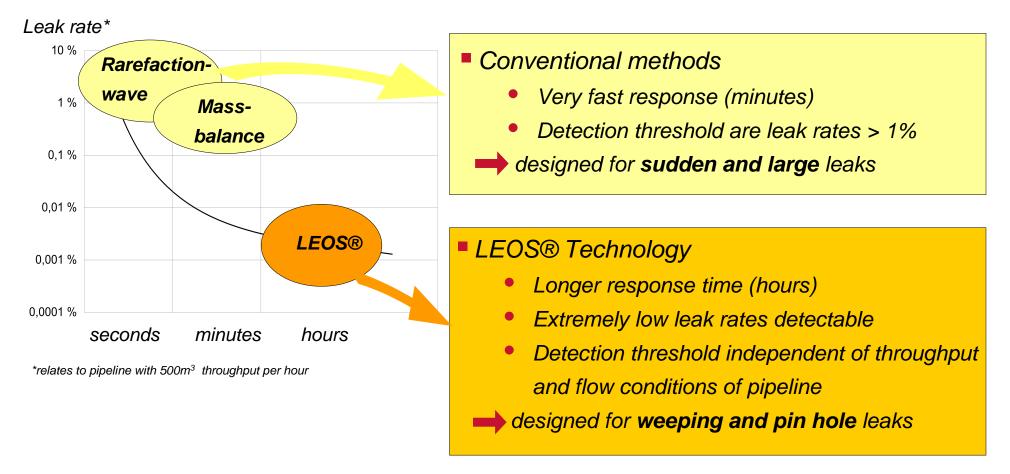
- *Production 80.000 bbl./day (500m³/h)*

- *Despite using flow-in/flow-out method, a spill of up to 0.5% (equal to 60m³ per day!) can for long remain undetected*

- *Within only 20 days a disaster with 1200m³ of oil spill can hit a sensitive environment*

Advantages of LEOS®:

- *LEOS® detects leaks in their very early stage – long before humans and environment would be significantly harmed*

- *LEOS® can simultaneously monitor pipeline bundles with different substances*

- *LEOS® works at all flow conditions (single-phase / multi-phase / no flow)*

- *LEOS® works for liquids and vapors, also in water*

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Conclusion: Additional Method required for Early Detection of Weeping / Pin Hole Leaks

Leak rate*

10 %

Rarefaction-wave

1 %

Mass-balance

0,1 %

0,01 %

LEOS®

0,001 %

0,0001 %

seconds   minutes   hours

*relates to pipeline with 500m³ throughput per hour

- **Conventional methods**
  - Very fast response (minutes)
  - Detection threshold are leak rates > 1%
  ➡ designed for **sudden and large** leaks

- **LEOS® Technology**
  - Longer response time (hours)
  - Extremely low leak rates detectable
  - Detection threshold independent of throughput and flow conditions of pipeline
  ➡ designed for **weeping and pin hole** leaks

» *Conventional methods and LEOS® are **complementary***

Contents

▶ **Motivation: Why detect low threshold oil leaks?**

▶ **LEOS® Monitoring method, Hardware & Software**

▶ **Arctic LEOS® case study 1: BPXA Northstar Pipeline / Prudhoe Bay**

▶ **Arctic LEOS® case study 2: BPXA OT-21 Flowline / Prudhoe Bay**

▶ **Conclusions / Summary**

LEOS® Monitoring Method

① **Leak**

② **Test Peak Generator**

Sensor tube

Air flow

Diffusion layer

Ⓜ **Measuring Station**

vapor from leak transported in air stream

Concentration

Alarm threshold

Position = purge time x flow velocity

- *Detection and localization of leaks*
- *Transport of leak substance to measuring station*
- *Analytical identification of leak substance*

Diffusion Principle

Molecules of leak substance

Test gas injection

Gas sensor(s)

Pressure difference

Leak

Test peak

Signal

alarm threshold

Test peak window (for self-test)

Tube position

leak position = purge time x mean flow velocity

Accuracy of leak localization is 0.5% of the tube length (± 50 m for 10 km)

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LEOS® System Components
Sensor Tube

Standard type (operating temperature > 0℃)

Perforated inner tube

Diffusion layer

Protective layer (braided plastic strips)

High performance type (operating temperature > -40°C)

Outside diameter: ≈ 16 mm

➡ *Diffusion layer is **permeable**, but air-tight (i.e. not porous)!*
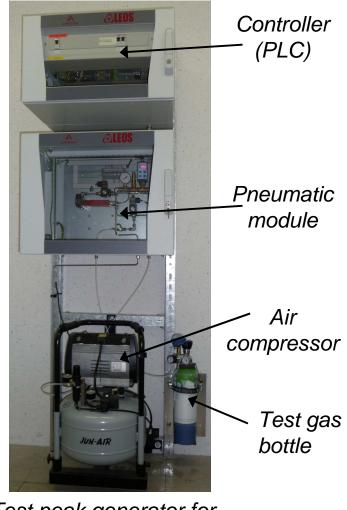
LEOS® System Components
Measuring Station (MS) and Test Peak Generator (TPG)

External gas analyzer (option)

Gas cooler (option)

Basic configuration

Measuring station with gas analyzer and gas cooler

Controller (PLC)

Pneumatic module

Air compressor

Test gas bottle

Test peak generator for pressure mode

Contents

► **Motivation: Why detect low threshold oil leaks?**

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► **Conclusions / Summary**

Arctic LEOS® Case Study 1: BPXA Northstar Pipeline (2000)

▶ History / Objective:

- **US Army Corps of Engineers: "*Installation of an Oil Spill Leak Detection System*"**

▶ Design Basis:

- **Monitoring of 6 miles subsea oil pipeline & gas pipeline**
- **15+ years lifetime**
- **Water depth 0 to 39 ft (0 to 12 m), burial depth 5 to 11 ft (1.5 to 3.4 m)**
- **60 °F (+16 °C) operating temperature / - 50 °F (-46 °C) during construction**
- **High salinity around the pipeline**
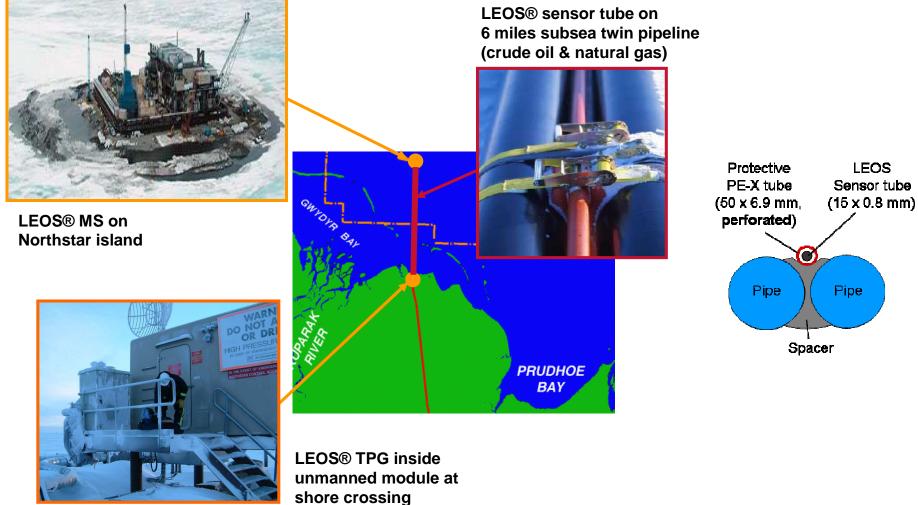
▶ Performance requirements:

- **Detection threshold: 32.5 bbl./day (= 200 l/h) or better requested**
- **Robust to survive installation and long-term operation in marine environment**

▶ Special challenges:

- **No damage to the sensor tube during installation ⇒ perforated conduit**
- **No false alarms triggered by secondary gases**
  (H_2 from sacrificial anodes, methane, H_2S and CO_2)
- **High humidity in received air flow ⇒ no condensation / icing of sensor tube**

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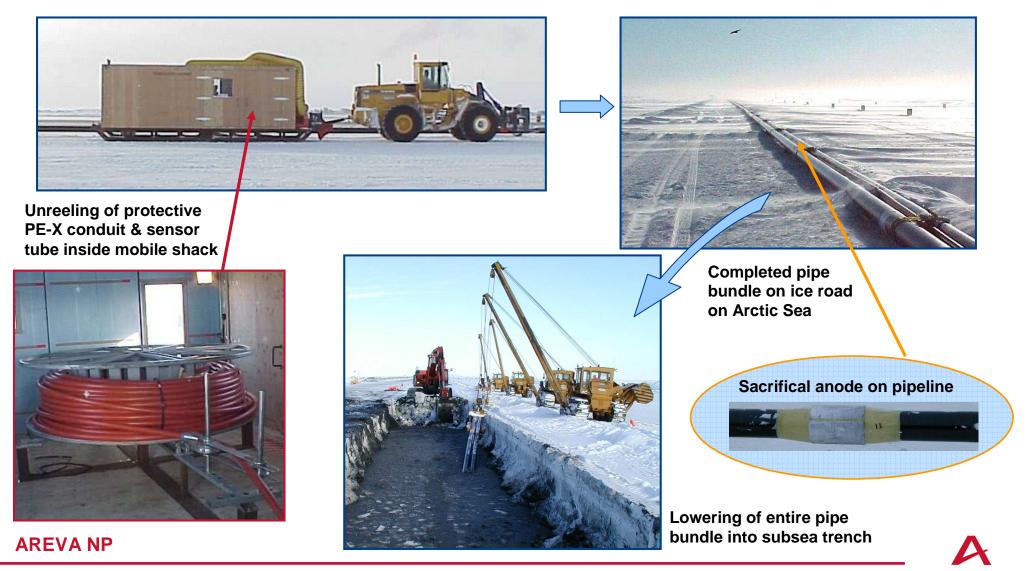
BPXA Northstar – Overview

LEOS® MS on
Northstar island

LEOS® TPG inside
unmanned module at
shore crossing

**LEOS® sensor tube on
6 miles subsea twin pipeline
(crude oil & natural gas)**

Protective
PE-X tube
(50 x 6.9 mm,
perforated)

LEOS
Sensor tube
(15 x 0.8 mm)

Pipe   Pipe

Spacer
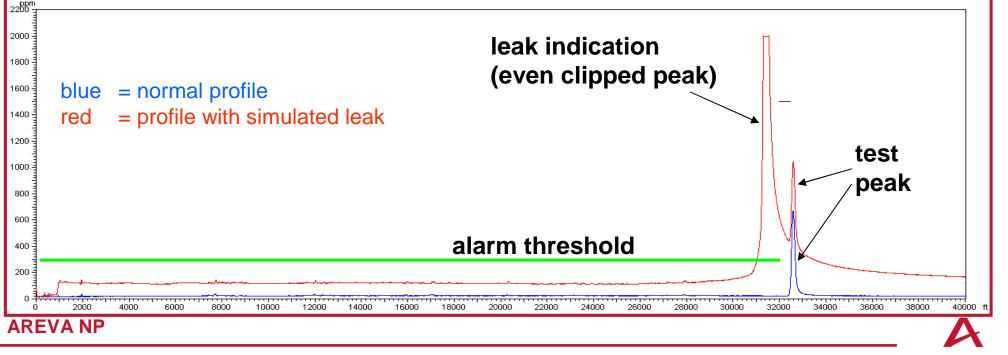
BPXA Northstar - Installation of LEOS® Tubes

Unreeling of protective PE-X conduit & sensor tube inside mobile shack

Completed pipe bundle on ice road on Arctic Sea

Sacrifical anode on pipeline

Lowering of entire pipe bundle into subsea trench

LEOS® Northstar
Leak Simulation Test after Upgrade 2010

▶ **Rugged infrared-based multi-channel gas analyzer (designed for industrial combustion & emission measurements)**

▶ **Test gas injection (1% butane) instead of former hydrogen test peak**

▶ **Test conditions: 8 ft (2.5 m) of sensor tube exposed to *1 liter crude oil* in sand, silt and seawater for only *17 hours*; at most distant tube location**

blue = normal profile
red = profile with simulated leak

leak indication
(even clipped peak)

test
peak

alarm threshold

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▶ **Effects on secondary gases:**

- ◆ H_2 eliminated by use of gas analyzer (no response to H_2)
- ◆ CO_2 eliminated by use of gas analyzer (no response to CO_2)
- ◆ H_2S eliminated by use of gas analyzer (no response to H_2S)
- ◆ H_2O <u>humid air</u> reduced by gas cooler
  <u>liquid water</u> periodically (≈3 months) removed by vacuum pump
- ◆ CH_4 separate methane sensor; cross-talk to butane signal eliminated by cross-compensation of gas analyzer

▶ **Butane gas (1%) injection instead of hydrogen test peak**

▶ **No false positives**

▶ **No system faults**

▶ **Almost maintenance-free**

▶ **Excellent verified sensitivity (1 liter crude oil after 24 hours)**

Contents

▶ **Motivation: Why detect low threshold oil leaks?**

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▶ **Arctic LEOS® case study 2: BPXA OT-21 Flowline / Prudhoe Bay**

▶ **Conclusions / Summary**

Arctic LEOS® Showcase 2: BPXA OT-21 Flowline (2007)

▶ <u>History / Objective:</u>

 ◆ **2006: Oil spill on OTL flowline in Prudhoe Bay oil field**

 ◆ **⇒ Increased agency requirements for pipeline safety**

 ◆ **⇒ Start of construction of new OTL flowline (17 miles)**

 ◆ **⇒ BP commits to installation of a pilot LEOS® system on first section (OT-21, 3.1 miles) in 2007/2008 (based on excellent operating experience with LEOS® at Northstar since 2000)**

▶ <u>Special challenges:</u>

 ◆ **Aboveground installation (⇒ mechanical issues to fix the sensor tube)**

 ◆ **Harsh operating conditions (blizzards, snow drifts, etc.)**

 ◆ **Dissipation of crude oil vapors by wind**

 ◆ **Diffusion process at arctic temperatures (-40 °F)**
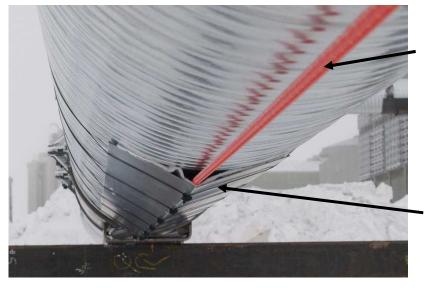
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LEOS® "OT-21 Flowline": Main Achievements

▶ **New type of sensor tube (diffusion at below -40°F)**

▶ **"V-channel" underneath pipe jacketing ($\Rightarrow$ keep leakage fluids and vapors at sensor tube)**

▶ **Oil sorbent cloth inside V-channel (keep air flow out and oil vapors in)**

▶ **Gas analyzer for hydrocarbon vapors**

▶ **New LEOS® system hardware & software design**

▶ **UL certified**

TÜV PRODUCT SERVICE
Safety tested
Production monitored
C NRTL US

UL 61010B
Certificate No.
U8 08 02 64760 001
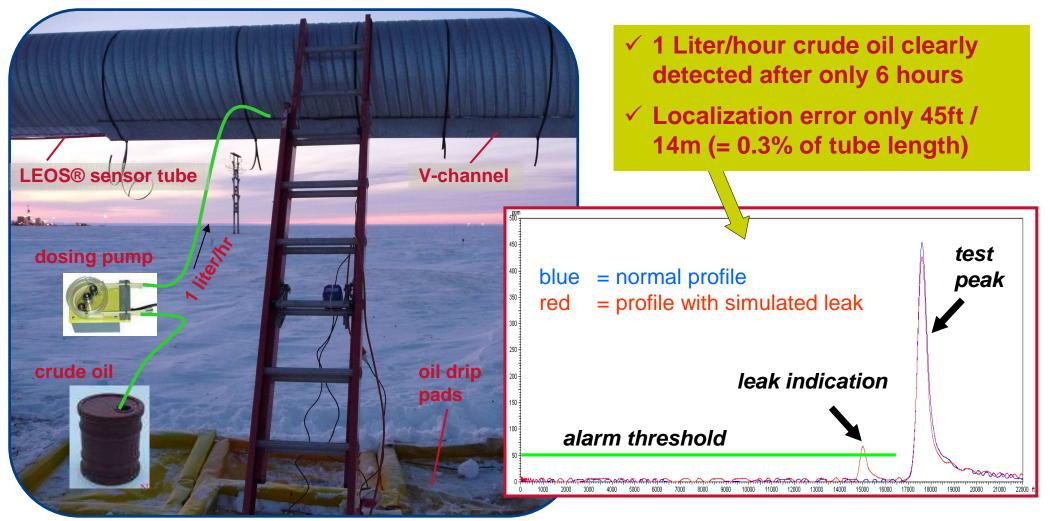
special sensor tube
("high performance")
for **arctic temperatures**

"V-channel" with
oil sorbent cloth

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LEOS® OT-21 / December 2008:
In-situ Leak Simulation Test at -20°F

LEOS® sensor tube

V-channel

1 liter/hr

dosing pump

crude oil

oil drip pads

✓ **1 Liter/hour crude oil clearly detected after only 6 hours**

✓ **Localization error only 45ft / 14m (= 0.3% of tube length)**

blue = normal profile
red = profile with simulated leak

test peak

leak indication

alarm threshold

LEOS® OT-21:
Performance Record after 3 Years

▶ **3 years of continuous LEOS® operation**

▶ **In-situ leak simulation test successfully demonstrated**

▶ **V-channel sheet segment (10 ft) detached by mechanical impact of snow&ice from snow blower:**

  ◆ **no damage to sensor tube occurred**

  ◆ **V-Channel reattached**

  ◆ **Working procedures for snow blower operators modified**

▶ **Blocked air flow through LEOS® tube by ice plug at TPG:**

  ◆ **Malfunction of air dryer (stuck ball valve) $\Rightarrow$ too high air humidity**

  ◆ **Immediate formation of ice crystals inside outdoor tube line**

  ◆ **Gradual clogging of LEOS® tube**

  ◆ **System alarm by LEOS® self-test as designed**

Contents

▶ **Motivation: Why detect low threshold oil leaks?**

▶ **LEOS® Monitoring method, Hardware & Software**

▶ **Arctic LEOS® case study 1: BPXA Northstar Pipeline / Prudhoe Bay**

▶ **Arctic LEOS® case study 2: BPXA OT-21 Flowline / Prudhoe Bay**

▶ **Conclusions / Summary**

LEOS® in the Arctic: Conclusions / Summary

▶ **Proven LEOS® technology over 35 years with 270 km of sensor tube already installed worldwide on various applications (pipelines & tanks, chemical plants, oil&gas)**

▶ **Successful adaptation of LEOS® to specific arctic needs**

▶ **No false positives thanks to selective gas sensors**

▶ **Single sections up to 6 miles (10 km) verified on arctic systems, up to 12 miles (20 km) on other applications**

▶ **Very low preventive maintenance scope**

▶ **Performance (both subsea and onshore) verified by in-situ leak simulation tests: 0.25 gal/hr (1 liter/hr) after 6…24 hours**

▶ **Approved by US Army Corps of Engineers and Environmental Agencies**

AREVA

Thank you for your attention

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"

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APPENDIX H

FLIR – GF-300 OPTICAL GAS IMAGING

Pipeline Leak Detection Conference

FLIR GF300 Series
for
Optical Gas Imaging (OGI)

David Shahon

Northwest District Manager

800-853-8331

David.shahon@flir.com

FLIR Product Line

An Infrared camera for every aspect of inspections

Expert Cameras

Automated Cameras for
24/7 Condition
Monitoring
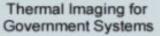
Small Handheld Solutions
for every department

Optical Gas Imaging for
VOC Gas Detection

Optical Gas Imaging Technology (OGI)

Can an Infrared Camera Really see Gas?

What can an OGI System See?
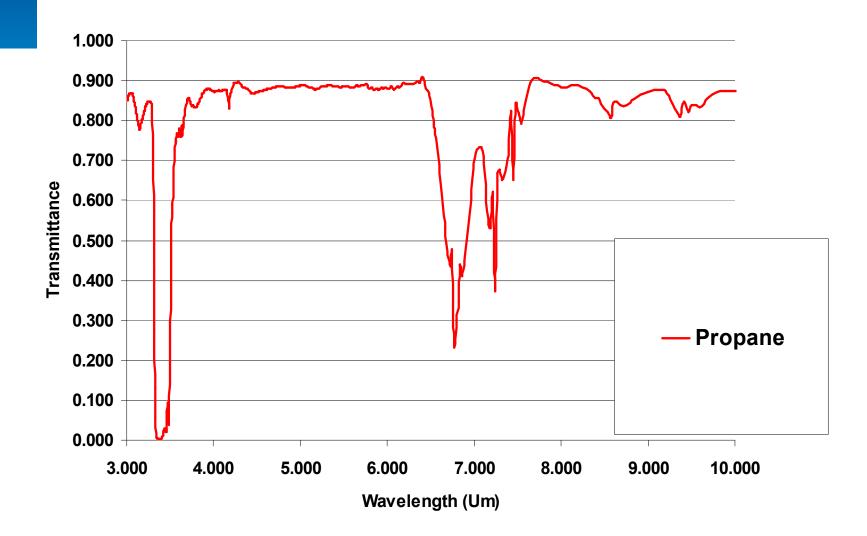
How does it work?

Infrared Gas Spectra

Infrared Gas Spectra
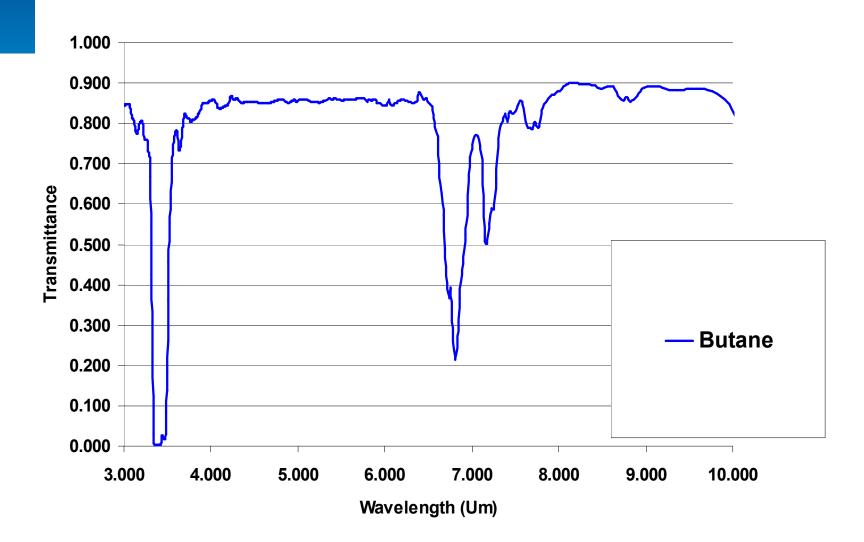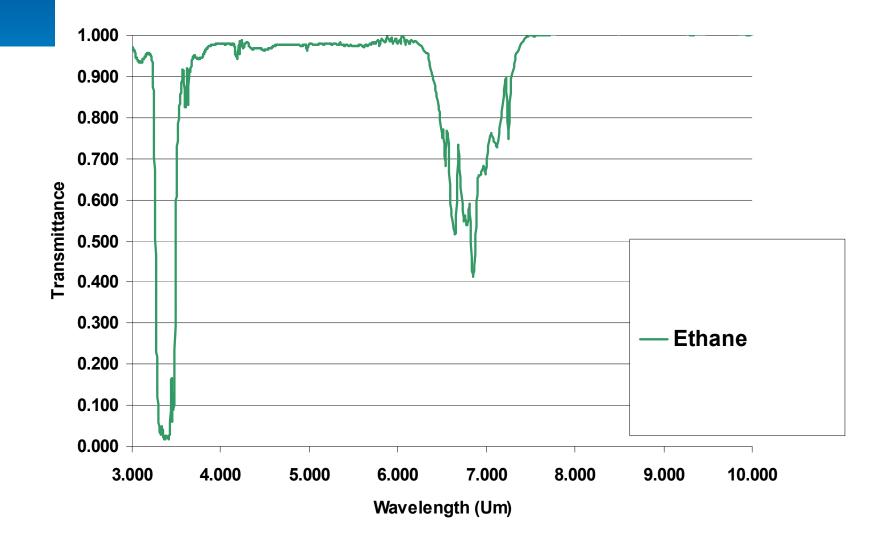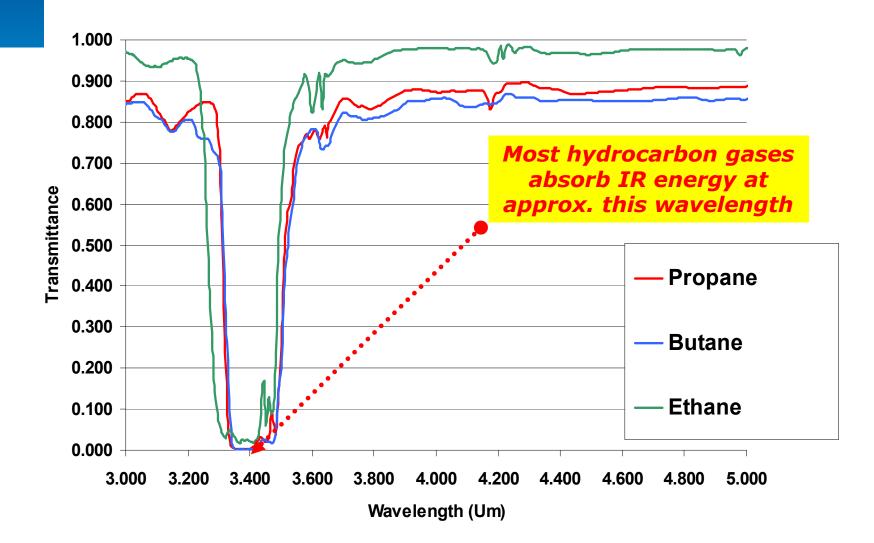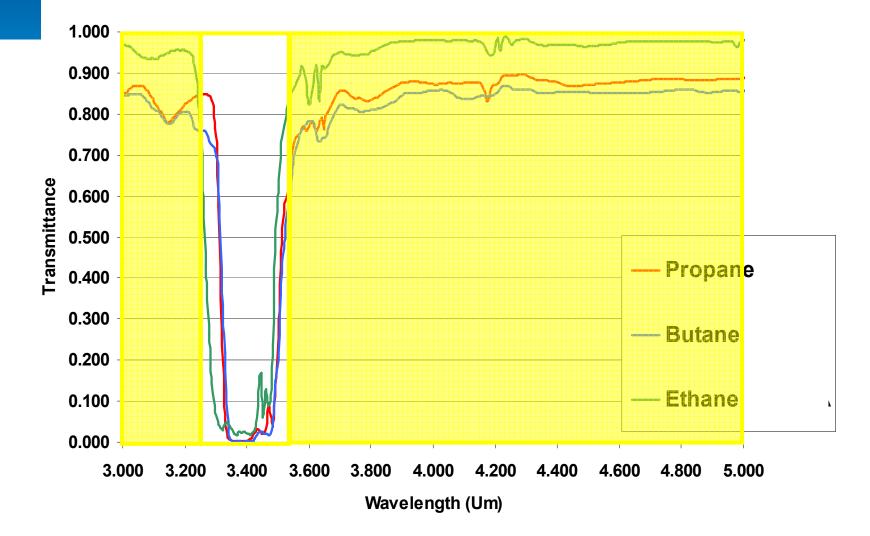
Infrared Gas Spectra
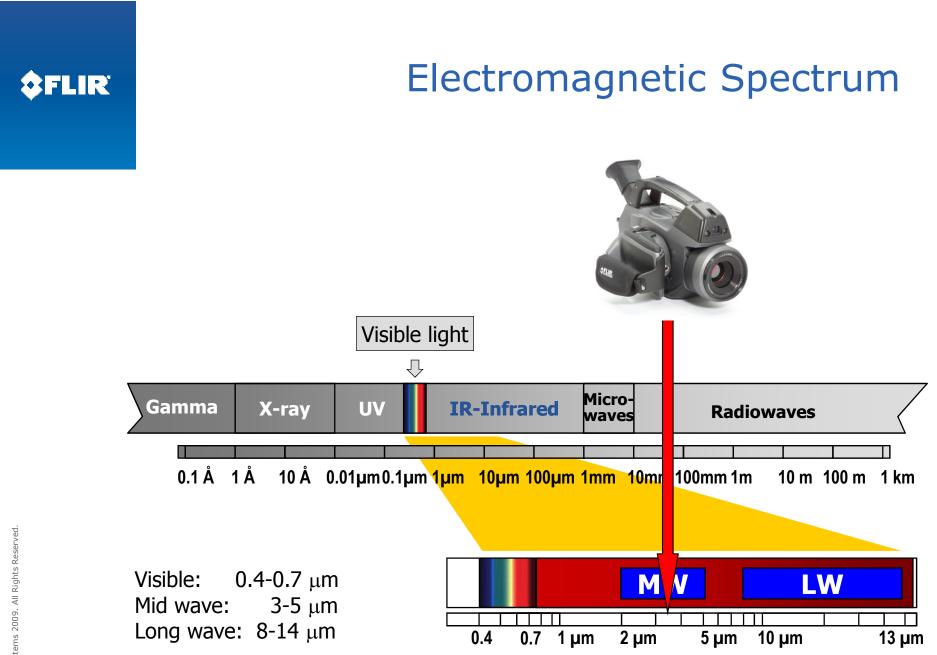
* Data intentionally skewed to protect proprietary filter location

Electromagnetic Spectrum

Visible light

| Gamma | X-ray | UV | | IR-Infrared | Micro-waves | Radiowaves |

0.1 Å 1 Å 10 Å 0.01μm 0.1μm 1μm 10μm 100μm 1mm 10mm 100mm 1m 10 m 100 m 1 km

Visible: 0.4-0.7 μm
Mid wave: 3-5 μm
Long wave: 8-14 μm

MW   **LW**

0.4   0.7 1 μm   2 μm   5 μm 10 μm   13 μm

GF Series

GF Series

Detection Limits

Tested Gases

- Benzene
- Butane
- Ethane
- Ethanol
- Ethylbenzene
- Ethylene
- Heptane
- Hexane
- Isoprene
- MEK

- **Methane**
- Methanol
- MIBK
- Octane
- Pentane
- 1-Pentane
- Propane
- Propylene
- Toluene
- Xylene

In an environment where there's no room for error, make room for the NEW FLIR GF SERIES!

- Real time visualization of invisible gas leaks
- Internal data/video storage, SD Card
- High resolution 4.3" flip-out LCD
- Radiometric with ±1% or ±1°C accuracy
- Visual camera 3.2 megapixels with built-in illuminators
- Built-in GPS
- Tiltable high resolution viewfinder
- Multi-angle handle with integrated direct access buttons
- High Sensitivity Mode (HSM) for detecting small leaks

Minimum Detectible Leak Rates (MDLR's)

FLIR

GasFindIR Camera - Tested OCT 2005	
Compound	g/hr
Benzene	3.5
Ethanol	0.7
Ethylbenzene	1.5
Heptane	1.8
Hexane	1.7
Isoprene	8.1
Methanol	3.8
MEK	3.5
MIBK	2.1
Octane	1.2
Pentane	3.0
1-Pentene	5.6
Toluene	3.8
Xylene	1.9
Butane	0.4
Ethane	0.6
Methane	0.8
Propane	0.4
Ethylene	4.4
Propylene	2.9

Distance = 3m, Wind = 0mph

MDLR's in Grams/Hr	Wind Speed in MPH		
Compound	0	2	5
Benzene	3.5	17.5	38.6
Ethanol	0.7	3.5	14
Ethylbenzene	1.5	7.6	17.5
Heptane	1.8	4.8	8.4
Hexane	1.7	3.5	8.7
Isoprene	8.1	14.3	38.8
Methanol	3.8	7.3	24.3
MEK	3.5	17.7	31.8
MIBK	2.1	4.9	13.3
Octane	1.2	3.4	8.7
Pentane	3.0	6.1	17.7
1-Pentene	5.6	19.7	43.8
Toluene	3.8	5.3	14.3
Xylene	1.9	9.1	18.9

Distance = 3m

Note: MDLR's tested in "standard" mode without the added benefit of High Sensitivity Mode (HSM)

Minimum Detectible Leak Rates (MDLR's)

FLIR

Methane-vs- Distance -vs- Optic

†MDLR in g/hr	Lens Back Focal Distance in mm								
Gas	25			50			100		
Standoff distance (m)	3	6	12	3	6	12	3	6	12
Methane MDLR	0.8	1.4	4.0	0.4	0.8	1.6	‡0.3	0.5	0.8
†MDLR was measured at 0 wind speed with no N2mixing.‡Lower limit of delivery system.									

Note: MDLR's tested in "standard" mode without the added benefit of High Sensitivity Mode (HSM)

MDLR versus concentration (ppm)

Leak Rate = 3 grams/hour

Is this a leak?

MDLR versus concentration (ppm)

Flame Out!
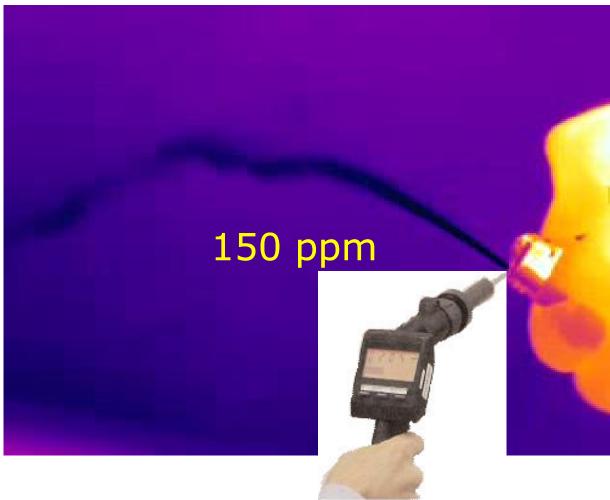
By Definition...this is a leak.

MDLR versus concentration (ppm)

150 ppm
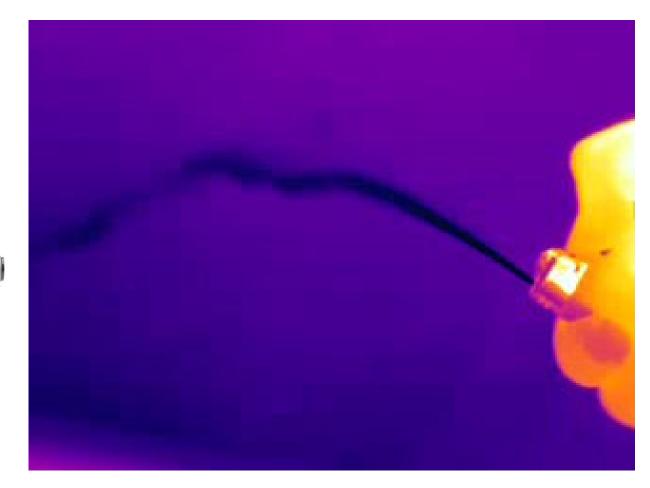
By Definition…this is <u>NOT</u> a leak.

MDLR versus concentration (ppm)

From 20' away…it's still a leak

Applications

- Offshore Production
- Onshore Production
- Well Heads

F97-264215 [RM] © www.visualphotos.com

- Pipelines
  - Transmission
- Gas Mains
  - Distribution

- Storage
    - Above & Below Ground
        - Vents, Vacuum breakers, Relief Valves

Outdoor – Flare Stack

Applications:

- Verify if flare stack is lit.

- Inside story: 36" (91.4cm) diameter opening and 1,400 lb/min (662.5 liter/min) flow rate.

- The customer has NO idea that the flare was NOT lit. Environmental Engineer was visibly shaken by our finding.

42 tons/hr.

Production Site

Primary Applications:

- Verify proper valve operation.
- These valves should be periodically checked to ensure proper combustion.
- Separator Dumps

Secondary Application:

- Check Tank Levels

Storage Tanks

Ergonomic Design

Designed for rugged uses

Data Storage and Access

Internal Data Storage
Two SD memory card slots
HDMI Video Output
Mini USB connectivity

Mini USB
HDMI Video

2 Options for Viewing

Flip out 4.3" COLOR LCD (800 x 480 pixels)
- High contrast for bright conditions

High Resolution Tiltable Viewfinder
- **COLOR** OLED, (800 x 480)

Even More Features

Built in VISUAL camera

 3.2 Mpixel color camera

 2 video lamps

 Record static images & visual VIDEO

Dual Useage!

Thermographically Calibrated

    GF320 calibration (-40°F to +662°F)

Image Noise Reduction

Scene-Based NUC

High Sensitivity Mode

Multiple Optics

Interchangeable Optics
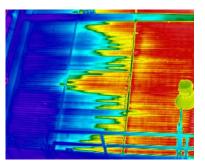
24° ("standard")
14.5° (2x telephoto)
6° (4x telephoto)
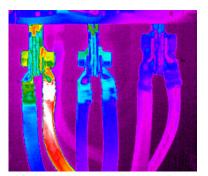
More Applications
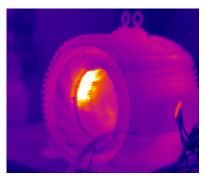
- Tanks (Gas leaks/Levels)
- Flares
- Welded pipe
- Insulated pipe
- Entire Vessel Inspection
- Exchangers / Fin Fans
- Valves / Relief Valves
- Steam Traps
- Electrical Connections
- Motors
- Unit Start Up Applications
- Temp. Measurement (GF320)

More Applications

Thanks!

APPENDIX I

TYCO THERMAL CONTROLS – TRACETEK 5000 HYDROCARBON SENSOR CABLE AND TT-FFS FAST ACTING FUEL PROBES

Direct Hydrocarbon Sensing Cable and Probes

Ken McCoy

Tyco Thermal Controls LLC

Key Points

- Setting the context
- Basics of conductive polymer leak detection
- Monitoring options
- Applications for the Alaskan Environment

What really matters?

- "If you only have a hammer, you tend to see every problem as a nail."
  -Abraham Maslow

- "It's a poor carpenter who carries only a hammer."
  -Ken McCoy

- SCADA based leak detection is fine for "fast" leaks

- Periodic testing or inspection works the day you run the test, but does nothing until the next test.

- Either or even both leave you vulnerable

A simple formula and its consequence

- Volume spilled = "leak rate" x "time to detect"
  - Detecting a "1% of the flow" leak in 30 minutes is pretty good.
  - But what if the system fails to detect:
    - a 0.5% leak in 1 hour
    - a 0.1% leak in 10 hours
    - a 0.01% leak in 10 days
  - Which results in the biggest spill?
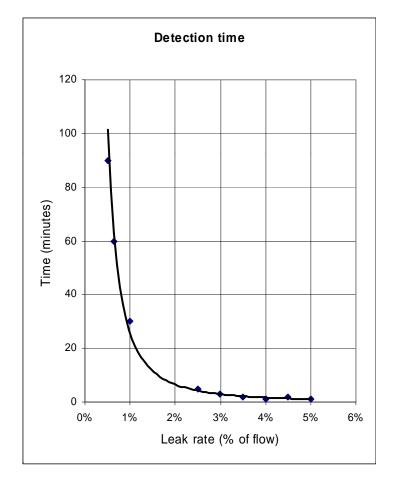
  (0.01% for 10 days is 5 times larger than any of the others)

Characteristic Response of generic SCADA based systems

Detection time

Time (minutes) vs Leak rate (% of flow)
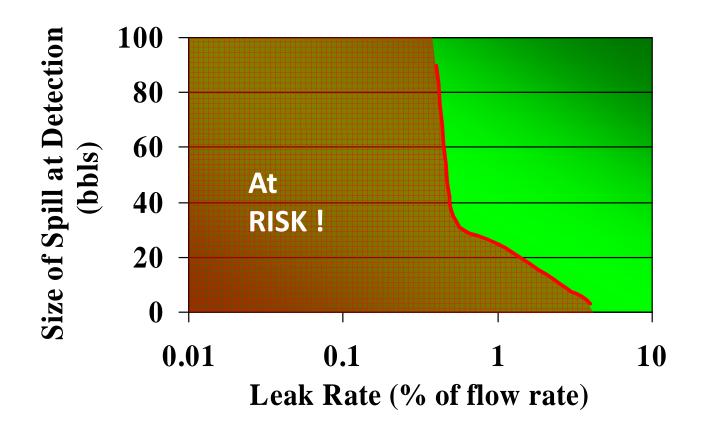
- Response time is faster for higher leak rates
- End User experience indicates good performance down to about ~1 to 2% of flow
- Greater leak sensitivity increases risk of false alarms

Implications of "ignoring" weeps and seeps

Spill volume for a 5000 bbl per hour line using SCADA based leak detection only

At RISK !

Size of Spill at Detection (bbls)

Leak Rate (% of flow rate)
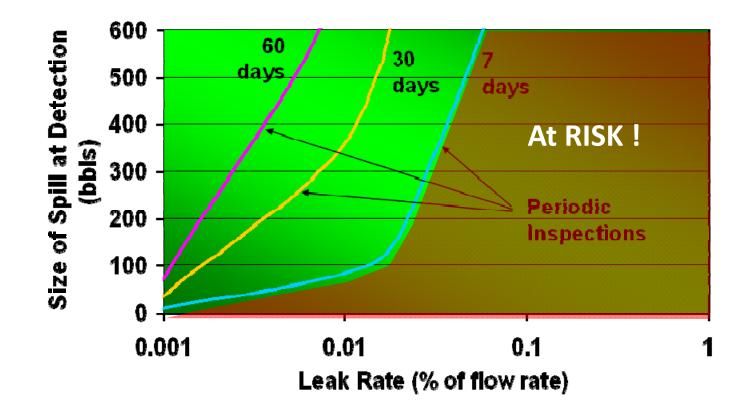
Implications of periodic inspection

Spill volume for a 5000 bbl per hour line with periodic inspections
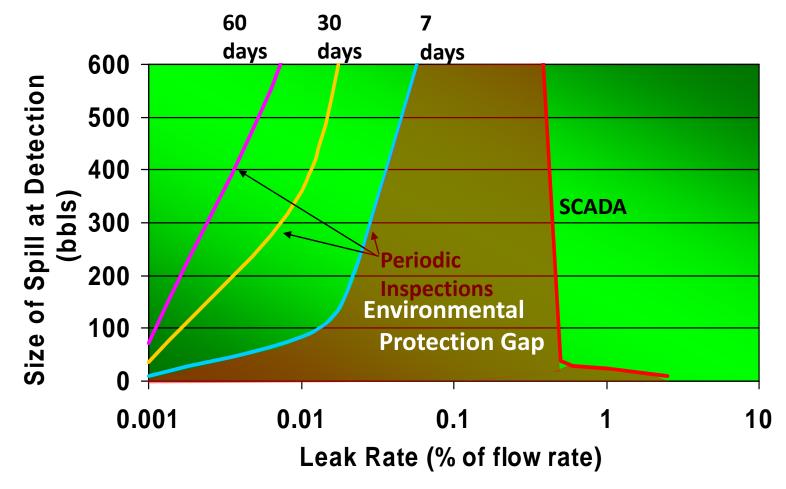
Combining SCADA with periodic testing

- Cable needs to be near the source of possible leaks
  - For pipelines that means buried in the same trench or strapped to the bottom of above ground pipe
- The cable takes time to respond but it responds to less than a few milliliters of leaked fuel
- So for "weeps and seeps" the cable detects and locates a leak while the spill size is very small
- But for "fast" leaks, the cable is too slow to prevent a large spill.

tyco / *Thermal Controls*

TraceTek.
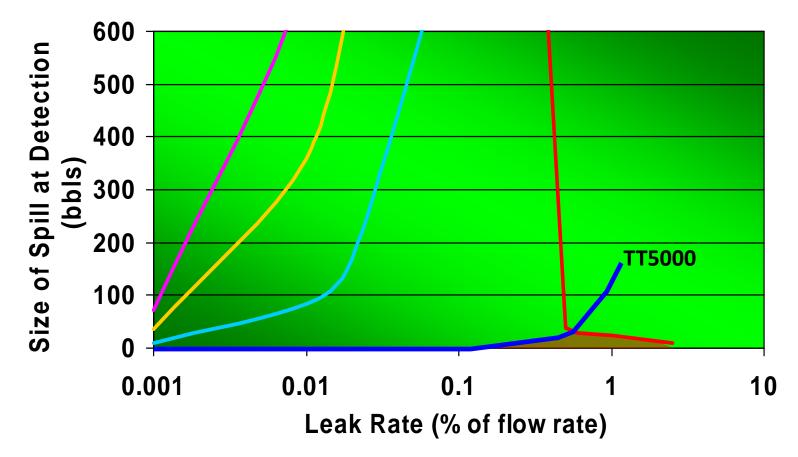
Impact of TT5000 sensor cable "hybrid solution"

Spill volume for a 5000 bbl per hour line with "hybrid system"

- Y-axis: Size of Spill at Detection (bbls)
- X-axis: Leak Rate (% of flow rate)
- Curve labeled: TT5000
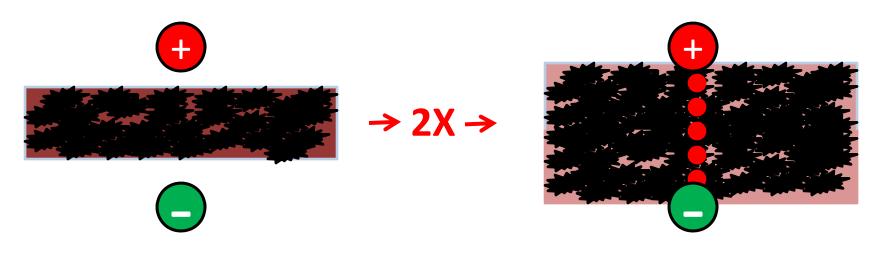
Detection Based on Conductive Polymers

Sensor cable is based on carbon loaded polymers that swell when exposed to hydrocarbons

No Hydrocarbons → 2X → Hydrocarbons Present
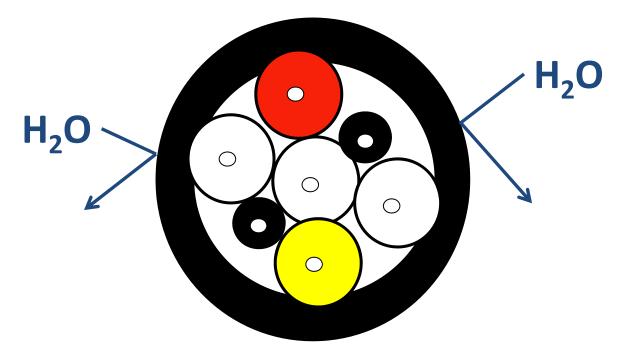
Sensor Cable for Hydrocarbon

- TT5000 How it works...

Sensor Cable for Hydrocarbon

- TT5000 How it works…

Crude Oil

Refined Products

tyco / *Thermal Controls*

TraceTek.
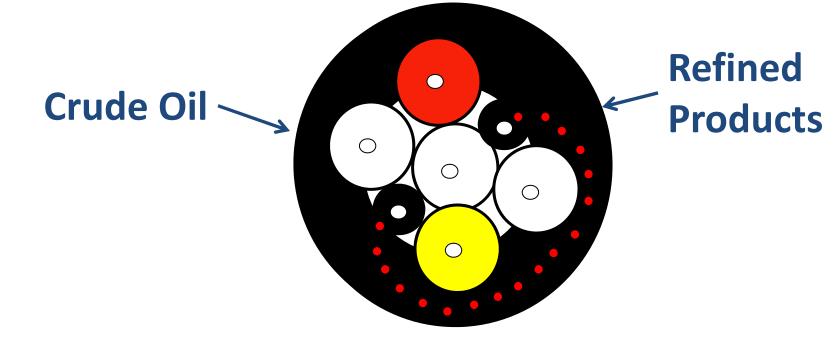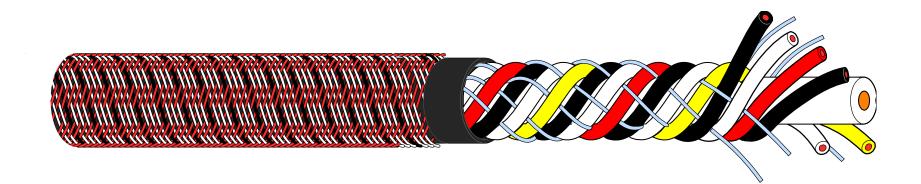
TT5000 Hydrocarbon Sensor
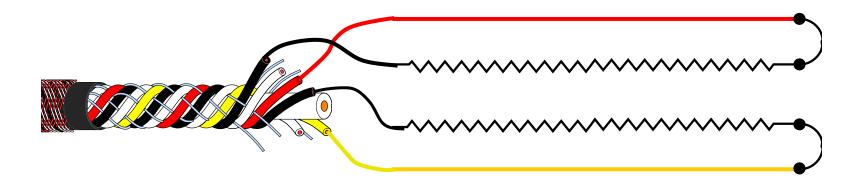
TT5000 for crude oil and refined products

Basic Cable Circuit
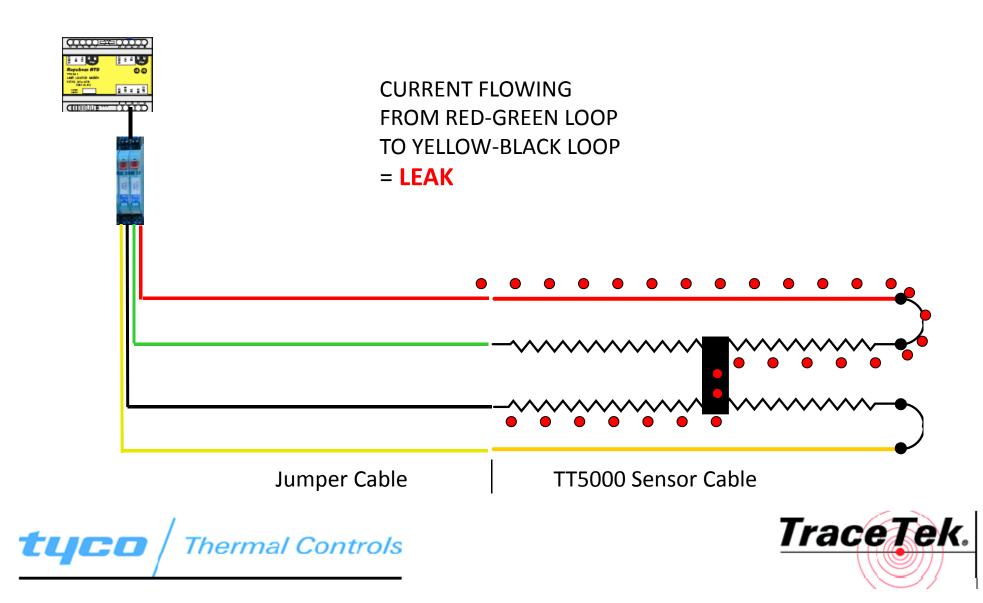
Circuit Diagram (No Leak)
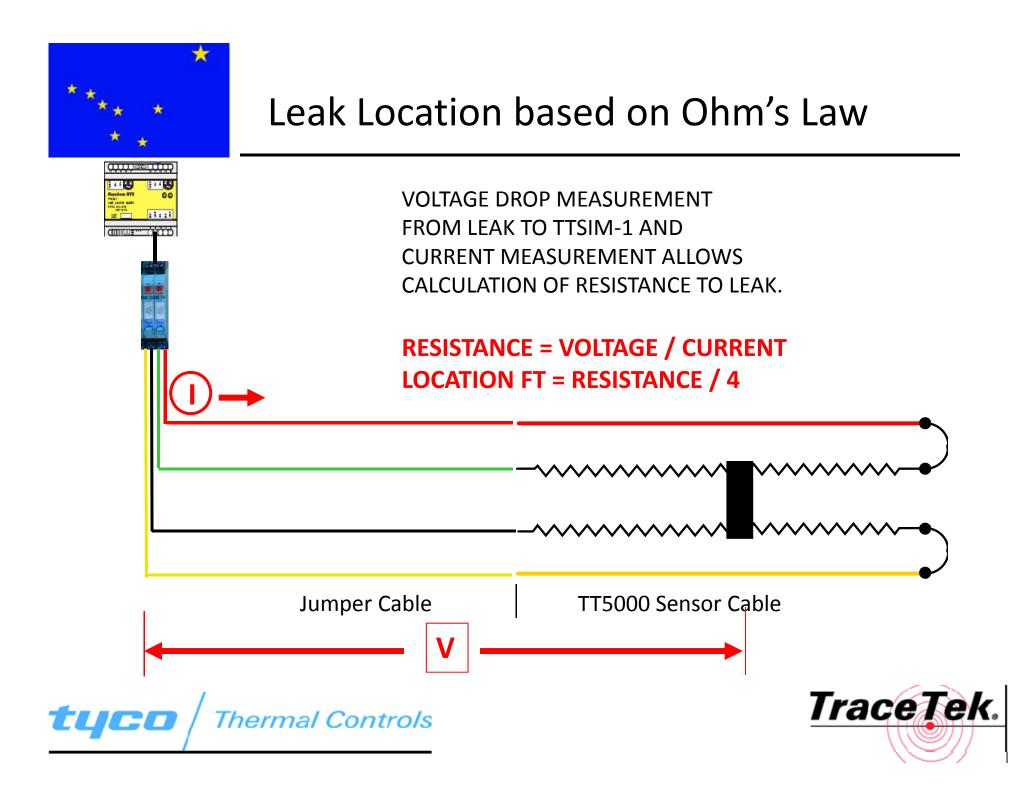
Detection based on conductive path between electrodes

CURRENT FLOWING
FROM RED-GREEN LOOP
TO YELLOW-BLACK LOOP
= **LEAK**

Jumper Cable | TT5000 Sensor Cable

tyco / Thermal Controls

TraceTek.

Leak Location based on Ohm's Law

VOLTAGE DROP MEASUREMENT
FROM LEAK TO TTSIM-1 AND
CURRENT MEASUREMENT ALLOWS
CALCULATION OF RESISTANCE TO LEAK.

RESISTANCE = VOLTAGE / CURRENT
LOCATION FT = RESISTANCE / 4

I →

Jumper Cable

TT5000 Sensor Cable

V

Three varieties of TT5000

- TT5000-SC for double wall pipe and indoor uses

- TT5000-HS for buried applications
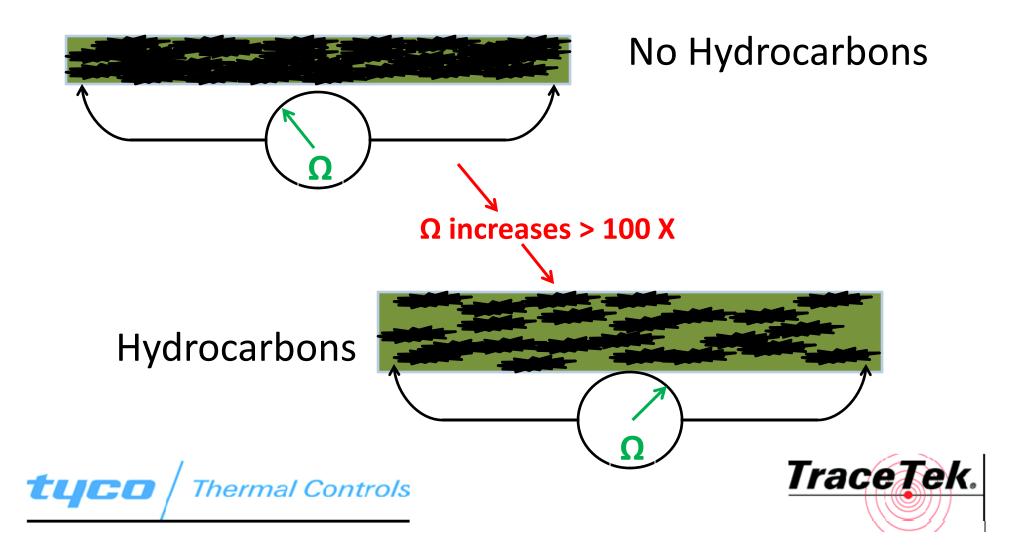
- TT5000-HUV for above ground pipe and outdoor applications
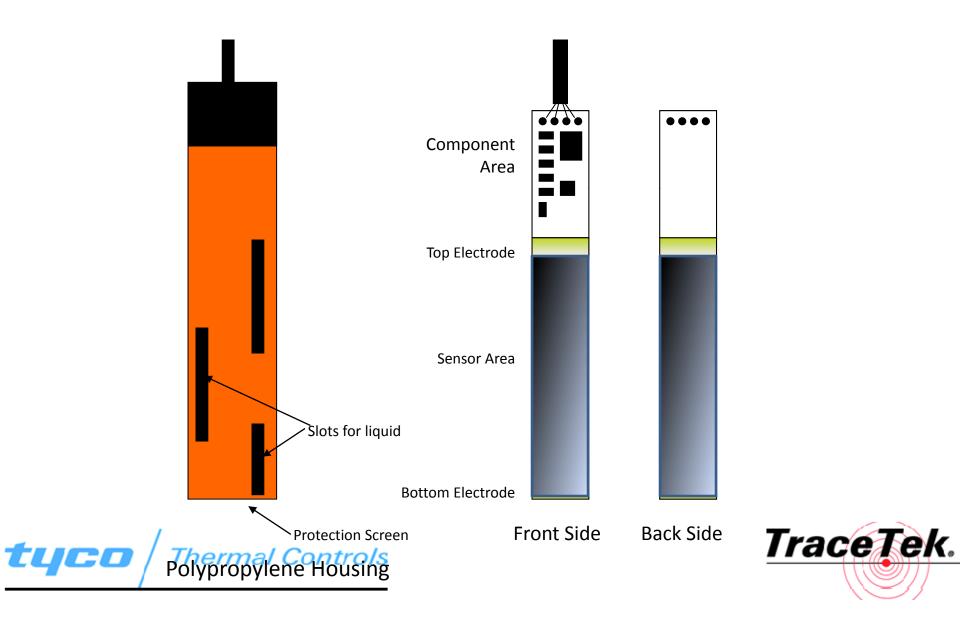
Point Detectors are based on changes in thin film resistance

No Hydrocarbons

Ω increases > 100 X

Hydrocarbons

Ω

Ω

TT-FFS uses thin film of conductive polymer on both sides of sensor blade

Component Area

Top Electrode

Sensor Area

Bottom Electrode

Slots for liquid

Protection Screen

Polypropylene Housing

Front Side   Back Side

TT-FFS

Point/Small Area Monitoring

TT-FLASHER-BE

- High efficiency LED's that can easily be seen when a leak is detected.

- When the sensor is contacted by the fuel or oil, the LED's will begin to flash at one second interval.

- Zone 0 Approval –Intrinsically Safe

- Flashing will continue for at least 30 days

- 2 x "AA" cells.   2 year battery life.

- Low battery warning (double flash) and test button

Dry Contact Monitoring

TTC-1

- Short Length applications
  - 30 m of TT5000
  - Up to 8 TT-FFS
- Two relays
  - One for leak detection
  - One for trouble
- Simple status indication
- Low input voltage
  - AC or DC

- Part of IEC16508 SIL-2 Rated System

Analog Monitoring

- Short Length applications
  - 50 m of TT5000
  - Up to 3 TT-FFS
- 4-20 mA transducer
- Galvanic Isolation
- C1D1 /Zone 0 approval in progress
- Part of IEC16508 SIL-2 Rated System

Current (mA)	System Status
Output <3.5	Damaged wire between control room and transmitter
4.0 mA	Cable Break in sensor circuit
6.7 ma	System Normal – No LEAK No BREAK
Output > 11	One TT5000 or FFS has detected a leak

TT-TAR

tyco / Thermal Controls

TraceTek.

Both Cable and Probe are Directly Compatible With Emerson's Wireless Mesh System

Up to 500' of TT5000
and/or
Up to 3 TT-FFS Probes

Output to:
- TTDM-128
- Touch Screen
- Direct to DCS software

SIM - Sensor Interface Modules

TTSIM-1

Long range   -- up to 1500 m of cable
Location accurate to +/- 1 m
12 Vdc, 24 Vdc, 24 Vac
Pipelines, under floor tank monitoring

TTSIM-1A

Short range -- up to 150 m or 4 x FFS
Location accurate to +/- 1 m
Relay output for local alarm
12 Vdc, 24 Vdc, 24 Vac, 12 Vac, 230 Vac
Point sensing, over fill detection
Sumps, buried valves

TTSIM-2

Short range – 150 m or 4 x FFS
Location accurate to +/- 1 m
Relay and location display

ALL SIMs have Modbus RTU output to host system

tyco / *Thermal Controls*

TraceTek.

TT-TS12 Touch Screen User Interface

- 250 Channels
- Dynamic leak mapping on user input image
- Hundreds of relays if desired
- Event history for up to 5000 events
- Full Modbus-RTU and Modbus/TCP output to host
- Context sensitive help

Application for Alaska Scenarios

- Not suitable for single wall under water pipelines
- Not useful for inaccessible underwater double containment
- TT5000 has limited use for cold oil/cold cable scenarios
- Costly to retrofit next to existing buried lines, **but inexpensive to install for new lines or above ground lines**
- **TT5000 is very useful for hot or warm oil for above or below ground pipe and fittings**
- **Great for refined products**
- **Great for storage tank floors, buried valves and similar fittings**

Applications – Buried Pipe

- TT5000 sensor cable is installed in slotted PVC pipe and buried beside pipeline
- TT5000 detects any liquid hydrocarbon that is released into the soil: crude oil or refined products
- Long pipelines are segmented into 1 km circuits
- Leak location accurate to +/- 1 m anywhere in the system

Slotted PVC Conduit beside 18" pipeline

Pull boxes are space at 250 m interval
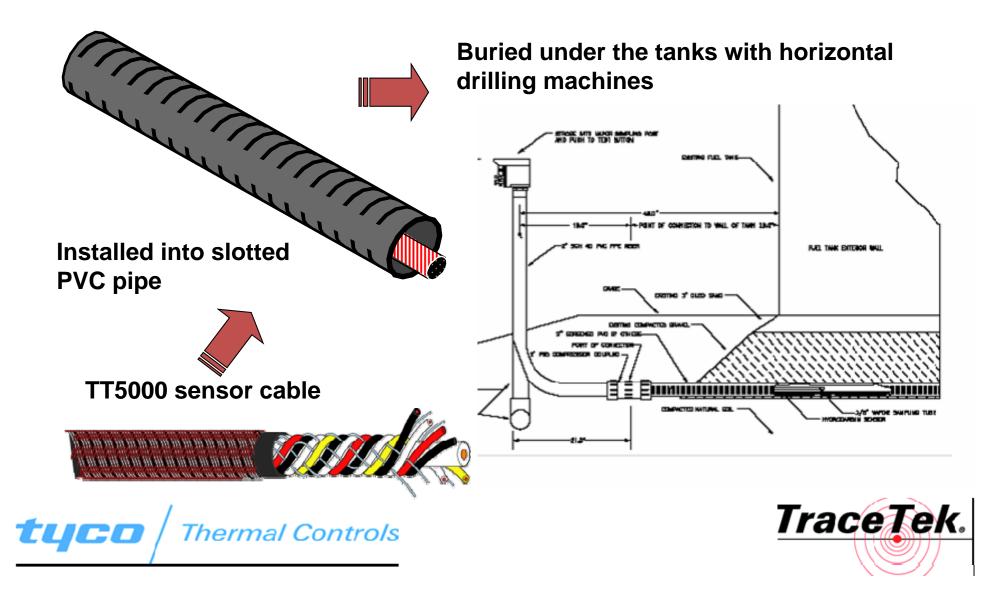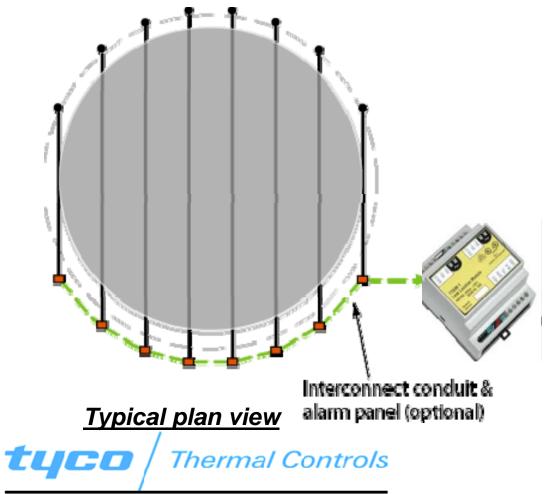
Applications – Tank Bottom

Buried under the tanks with horizontal drilling machines

Installed into slotted PVC pipe

TT5000 sensor cable

Applications – Tank Bottom

Typical plan view

Interconnect conduit & alarm panel (optional)

Applications – Above Ground Pipe

TT5000-HUV is strapped to bottom side of above ground pipe at terminals and wharfs.

Application – Cased Crossings and DC Pipe
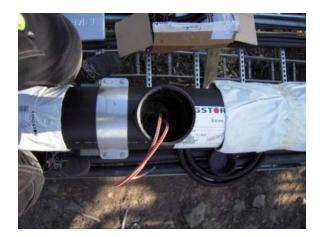
TT5000-SC or TT-FFS is inserted into end of cased road crossing

tyco / Thermal Controls

TraceTek.

Insulated Double Wall Pipe

Heated, Insulated and Leak Detected Double Contained Fuel Pipe at a Power Plant in Finland

Applications – Tank Overfill

- TT-FFS is placed in small concrete berm constructed around base of tank

- Any overfill or storm water with oil floating on water is detected

- 1, 2, 3 or 4 x TT-FFS depending on tank diameter and outflows

- Monitor with TTC-1,   TT-SIM, TT-TAR or MESH
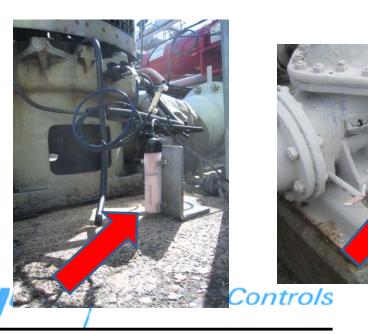
TT-FFS or TT5000-HUV can be used on pump pads, around small tanks and other fittings to monitor for early detection of leaks

TraceTek.

Summary

- Sensing cable is a compliment to SCADA based leak detection…not a competitor
- TraceTek leak detection based on conductive polymer technology and simple Ohm's Law instrumentation
- Pipelines and tank bottom coverage via TT5000 cable
- Fast acting, re-usable probes for sumps, overfill, casings, road crossings, pump pads, etc.
- Instrumentation options from simple to very complex facility level – full integration to existing alarm and monitoring systems

tyco / *Thermal Controls*

TraceTek.

A closing quote or two

- "Don't forget the other tools in your tool belt"

- "Think outside the ~~box~~" pipe"

APPENDIX J

FLIR – P-600 INFRARED CAMERA SYSTEM

Alaska Leak Detection Conference

FLIR P6xx Infrared Camera Systems
for
Finding Temperature Differences

David Shahon

Northwest District Manager

800-853-8331

David.shahon@flir.com

FLIR Product Line

An Infrared camera for every aspect of inspections

Expert Cameras

Automated Cameras for
24/7 Condition
Monitoring

Optical Gas Imaging for
VOC Gas Detection

Small Handheld Solutions
for every department

ThermaCAM P6xx

Handheld IR Camera

Oil on Water

Oil in snow

Process Equipment failures

* Wet or problematic Insulation over pipes

Expert FLIR P6xx Cameras

Includes:

Highest resolution available - 640x480 pixels
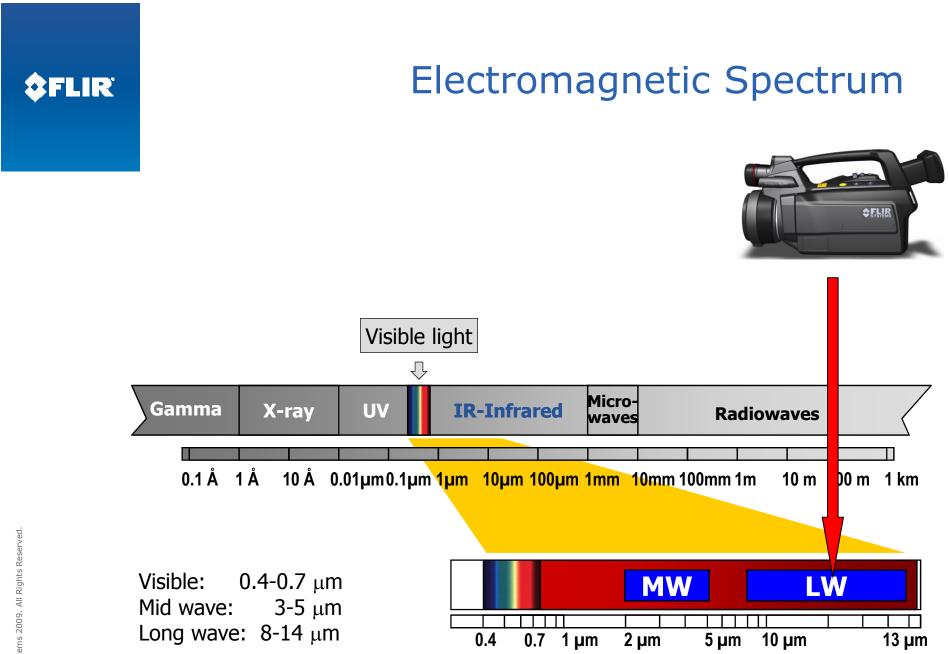
Best Ergonomic Design

Most Rugged – IP54

Lowest operating temperature
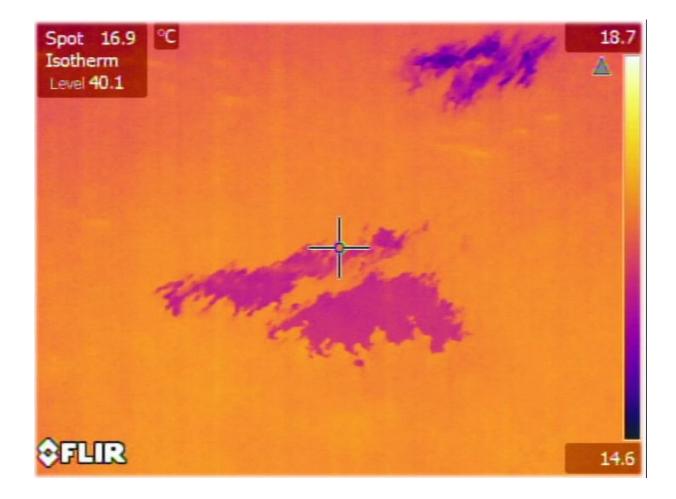
Linked Visual and IR images

GPS tagging on P660 Camera

Electromagnetic Spectrum

Visible light

| Gamma | X-ray | UV | | IR-Infrared | Micro-waves | Radiowaves |

0.1 Å 1 Å 10 Å 0.01μm 0.1μm 1μm 10μm 100μm 1mm 10mm 100mm 1m 10 m 00 m 1 km

Visible: 0.4-0.7 μm
Mid wave: 3-5 μm
Long wave: 8-14 μm

MW LW

0.4 0.7 1 μm 2 μm 5 μm 10 μm 13 μm

Does Infrared Work to find Oil on Water?

9/16/2011

8

Gulf oil Spill in Infrared
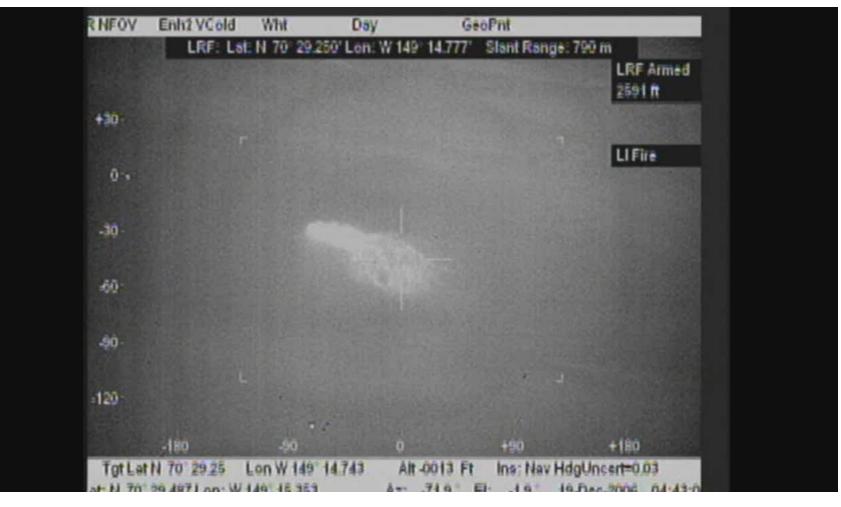
Gulf oil Spill in Infrared

Does Infrared Work to find Oil under Snow?

How are these inspections getting done?

Not Fun on cold Days!!

Fix Mounted Solutions

IR Evaluation of Foam Insulated Pipelines to Detect Trapped Water that Could Cause Corrosion Under Insulation (CUI)

Information credit to:
Doug Burleigh
La Jolla Cove Consulting, San Diego CA
ASNT Level 3 IR/T
Allen Sanders
Kakivik Asset Management (KAM), Anchorage AK
Manager of Quality/Training

Pipeline Inspection in Alaska

Kakivik Asset Management (KAM) provides inspection and technical support at drill sites on the North Slope Alaska oilfields, which are on the Arctic Ocean, and well above the Arctic Circle. KAM also provides services in the "lower 48".

The North Slope production pipelines are **not** part of the much larger (diameter) **Trans Alaska Pipeline System** (TAPS) that runs from the North Slope to Valdez

For several years, KAM has been using IR as the primary "screening" inspection method for examining pipelines that are part of the North Slope drillsite well lines.

IR can locate areas of water trapped in the foam insulation that covers steel piping systems. This trapped water can cause **CUI (Corrosion Under Insulation).**

Environment Conditions for IR

Fall and Spring are the best seasons to perform IR inspections

IR inspection is performed in darkness when there are no solar reflections
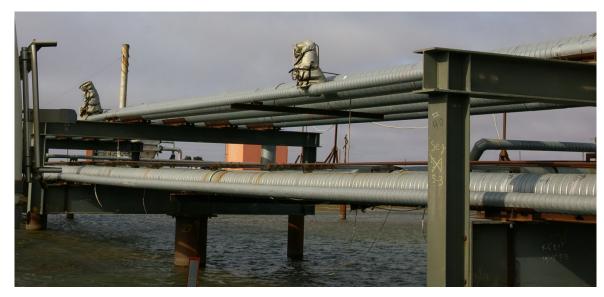
North Slope Pipelines

Pipes range in size from 2" to 6" with some exceptions.

The outside of pipes are covered with a thin (0.040 inch) galvanized steel "wrap" (sheath) to protect insulation from weathering...UV, solar, rain, ice, as well as mechanical impact.

The problem is that water gets into the foam insulation.

Water enters through any small opening.
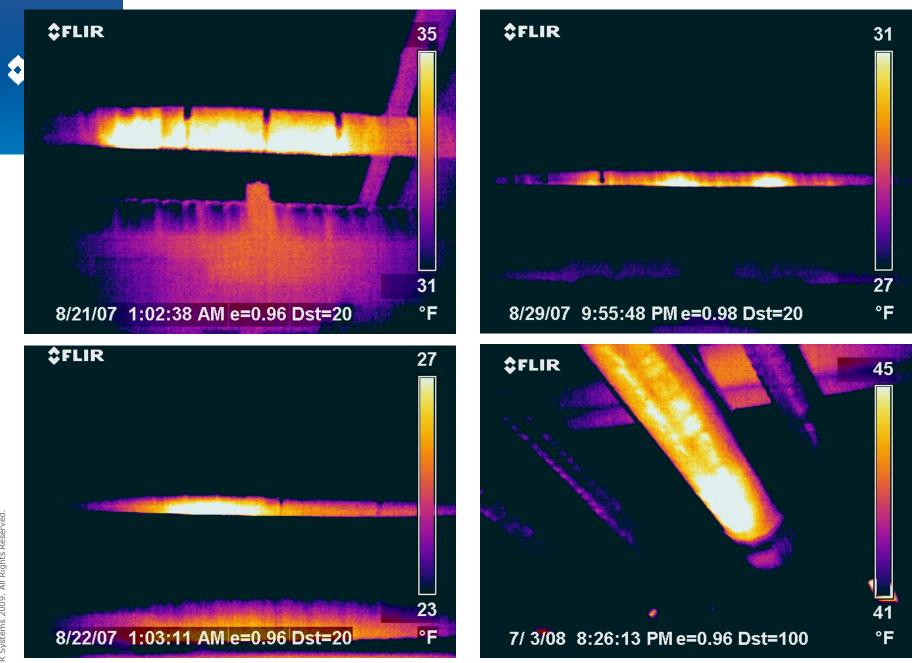
If enough water collects in the insulation, the water level will reach the internal steel pipe and will cause corrosion on the outside of the pipe.

Eventually the pipe can rust through from the outside in and leak. This is not viewed as a good thing.

This is not the same problem as corrosion, erosion, and pipe wall thinning on the inside of the pipe.

The IR test method does not detect pipe wall thinning on either side of the interior pipe. This is a different problem

IR inspection crew at North Slope

IR images of water trapped in foam insulation

Scope of IR Inspection

The IR procedure should be used as a relatively rapid qualitative "screening technique" to look for heavy concentrations of water in the foam insulation.

IR can scan multiple pipes concurrently and quickly, and is a good qualitative screening method.

It is not an exact science.

Anomalies found by IR are evaluated by secondary NDT methods including RT.

Limitations - Environmental

IR inspections are not permitted under specific conditions or <u>combinations</u> of the following

1. Ambient temperature
2. Delta temperature (ΔT)
3. Pipe geometry (outer diameter, inner pipe diameter, insulation thickness)
4. Wind speed
5. Precipitation (rain or snow) or water on pipes
6. Solar input and other reflections (cold, operators, vehicles, etc.)
7. Distance to pipe: generally not more than 30 feet, depending on the lens used.

IR Training and Certification

IR training and certification was performed under ASNT SNT-TC-1A.

Two IR specifications were written and approved.
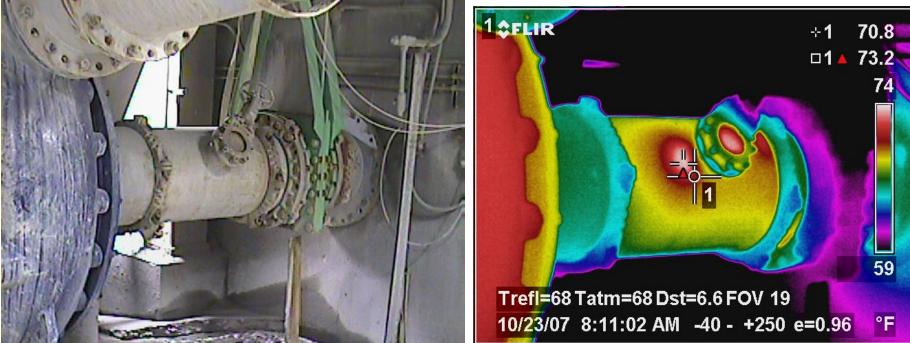
IR tests (General, Specific and Practical) were written.

Preventative Maintenance
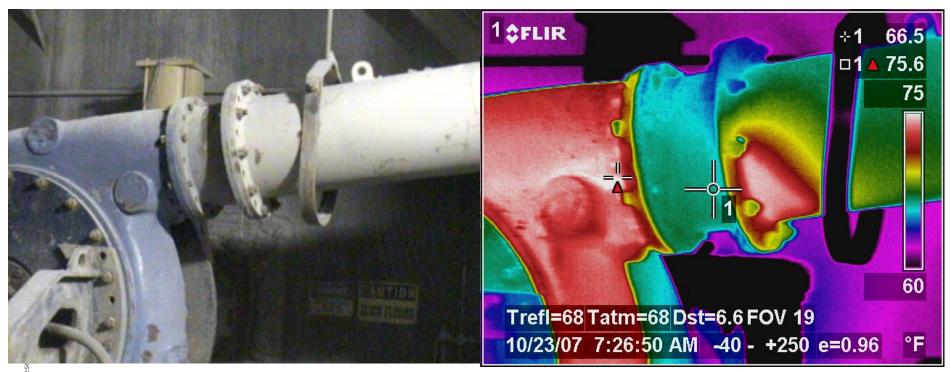
Wear in rubber lined pipe
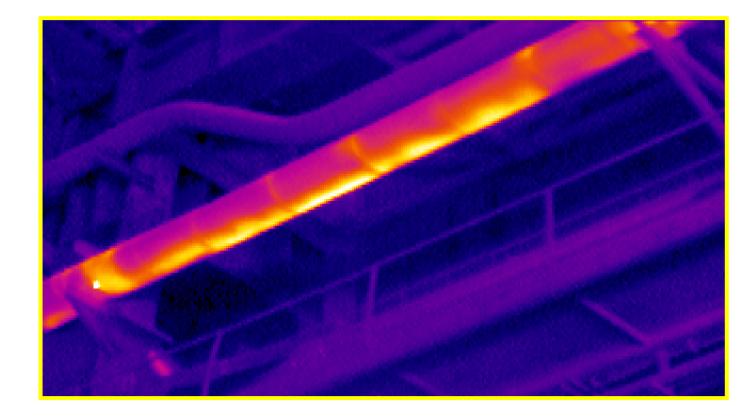
Lined Pipe Issues
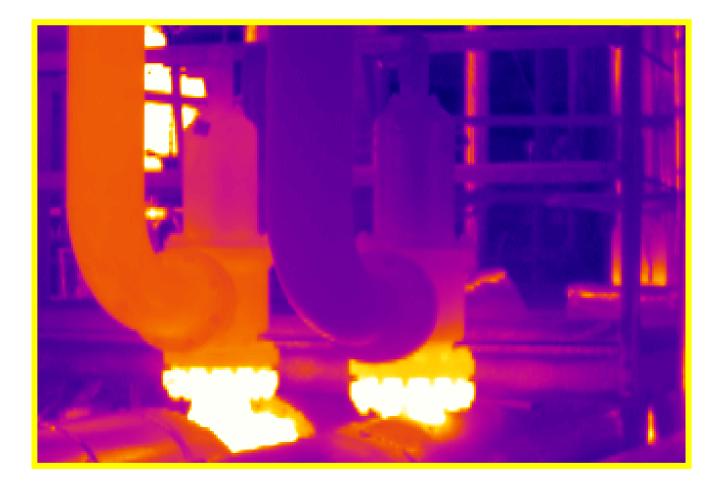
Heat Trace Systems
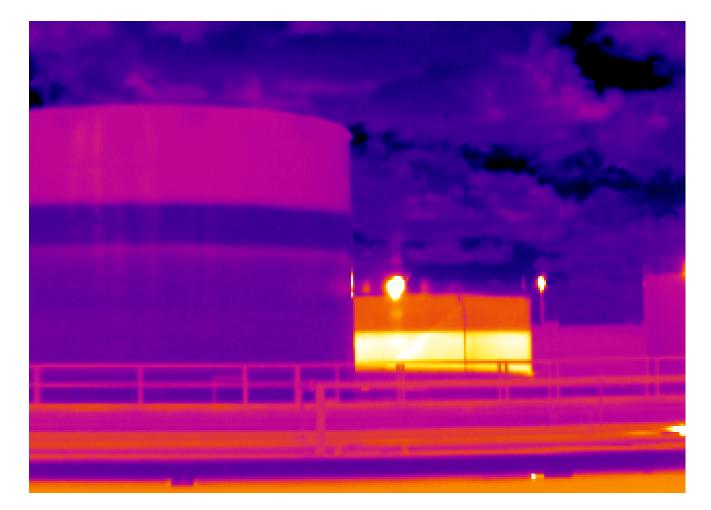
Leaks – Leaking Relief Valve

Thanks!

APPENDIX K

PERMALERT ESP, A DIVISION OF PERMA PIPE – PAL-AT

Liquid Leak Detection Technology
ADEC Pipeline Conf 2011

Art Giesler

Director of Sales

8190 Precinct Line Road

Colleyville, TX 76034

art.giesler@permapipe.com

817-849-1998

cell 817-239-2234

PermAlert ESP a Divison of Perma-Pipe, Inc.

‣ Perma-Pipe Established in 1961, Ricwil in 1910

‣ Division of MFRI, Inc.

   NASDAQ traded company

   $300 + million / year revenues

‣ <u>PermAlert ESP – Perma-Pipe:</u>

Engineering Company Providing Piping Systems and Liquid Leak Detection Solutions

$150 + million / year revenues

DHC, Environmental, Industrial, Oil & Gas, Mission Critical, Semiconductor and Mining Markets

Sensing Technology
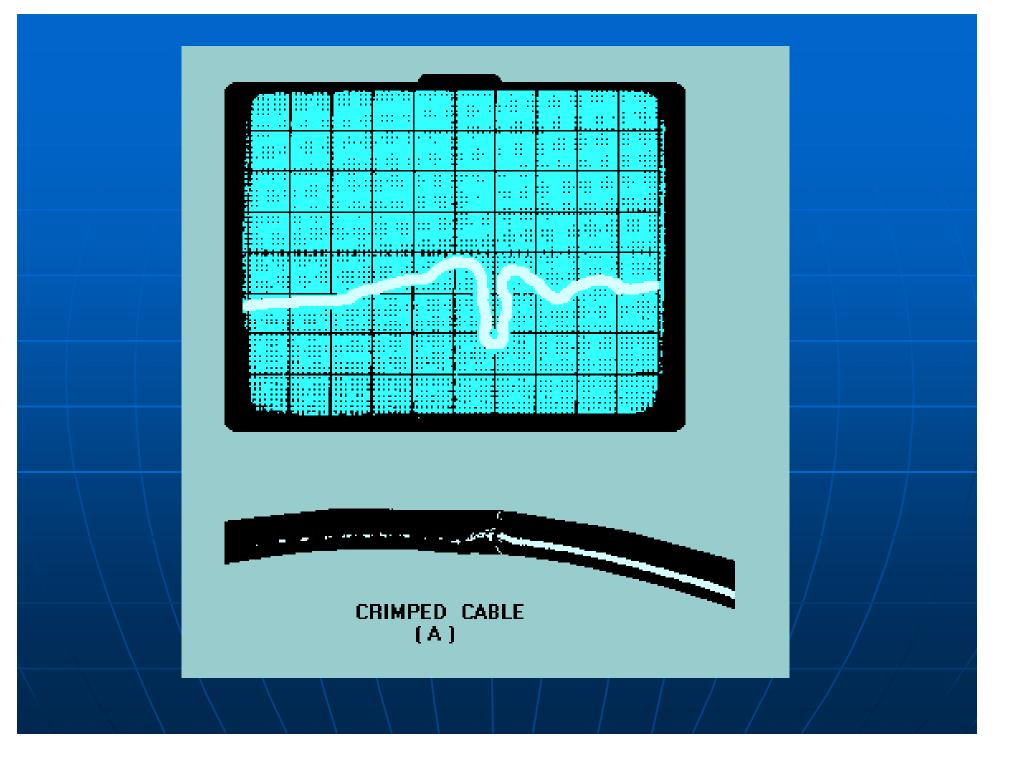
- Time Domain Reflectometry – Impedance based cable measurement – related to sonar/radar
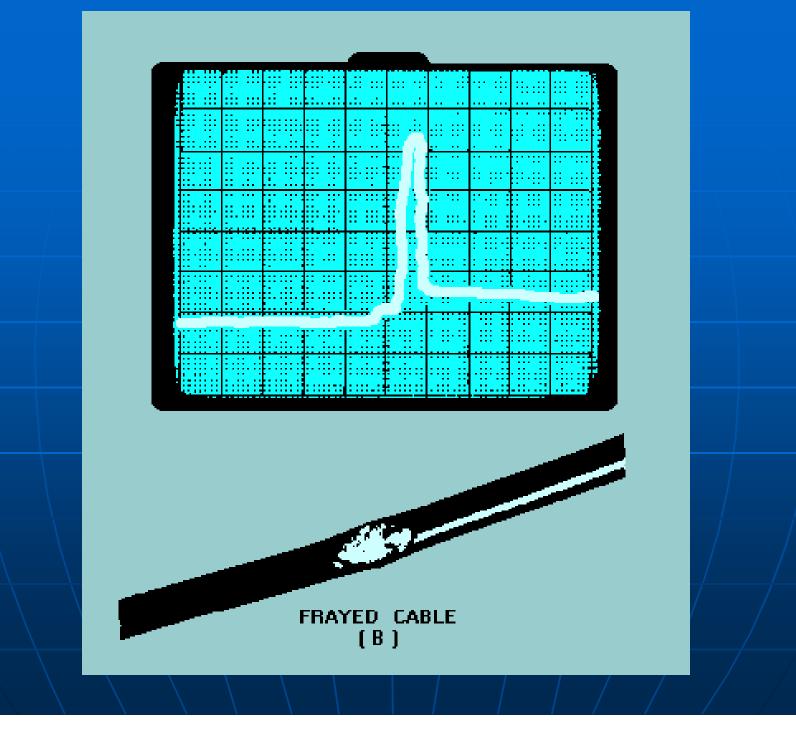
PAL-AT
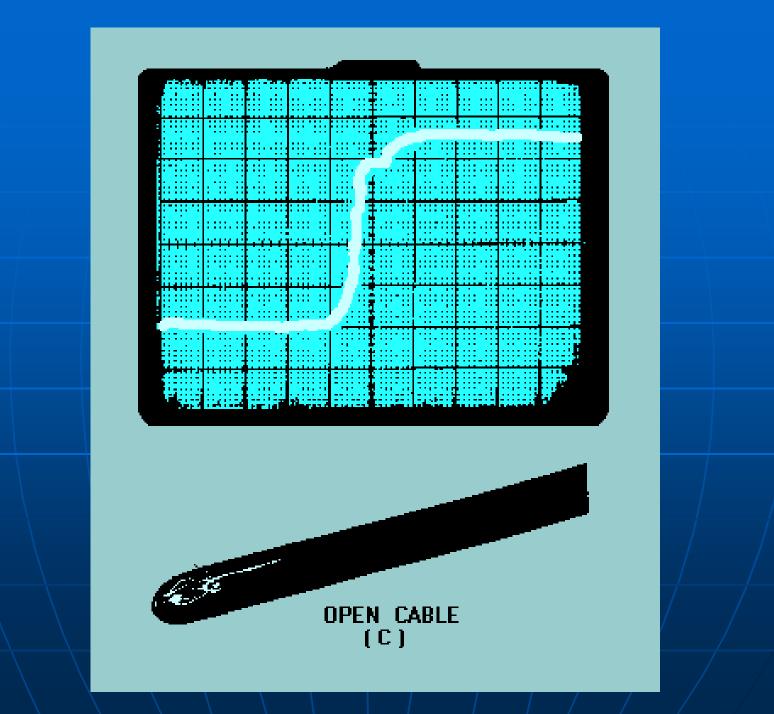
PAL-AT uses coaxial cables and probes to monitor for liquid leakage. The system can detect and locate leaks, breaks and shorts on the sensor cable as well as probe activations.
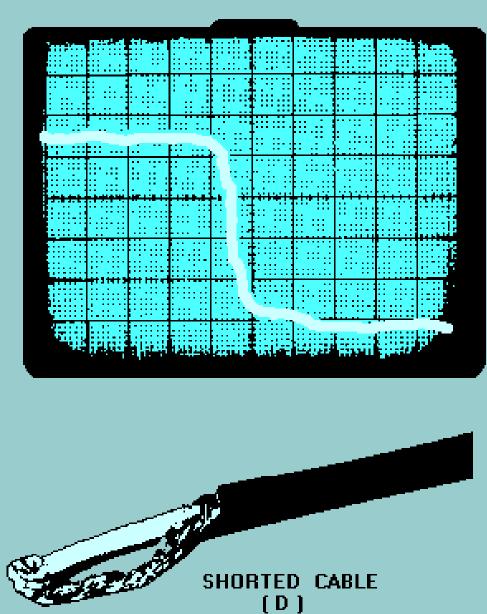
Time-domain reflectometry or **TDR** is a measurement technique used to determine the characteristics of electrical lines by observing reflected waveforms. The amplitude of the reflected signal can be determined from the impedance of the discontinuity. The distance to the reflecting impedance can also be determined from time that a pulse takes to return..

Electrical impedance, or simply **impedance**, is a measure of opposition to a sinusoidal alternating electric current

CRIMPED CABLE
(A)

FRAYED CABLE
(B)

OPEN CABLE
(C)
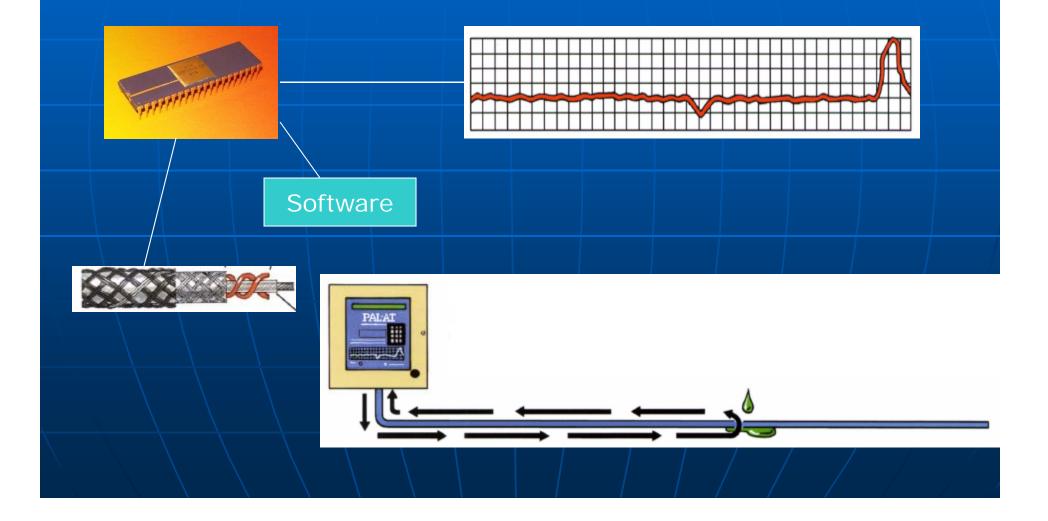
SHORTED CABLE
(D)

Combining Technology

Software
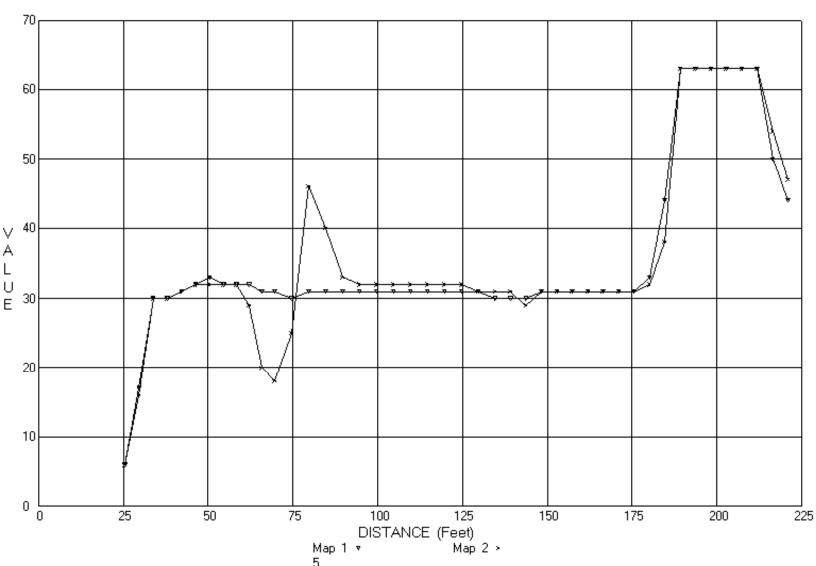
TDR Trace of Dry Cable

Dry Cable Response
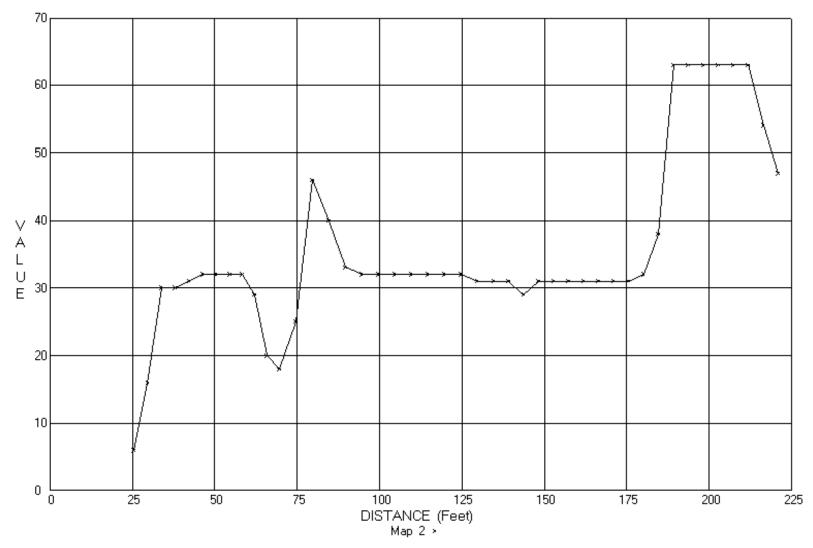
TDR Trace of Wet Cable

Liquid Detected at 60' on Map 1

Monitoring of Wet Cable
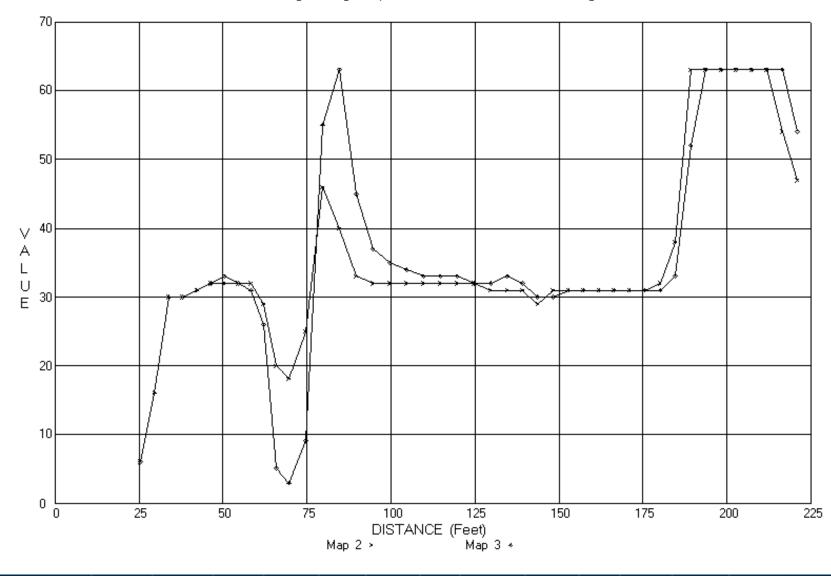
Monitoring Using Map 2 and Wet Cable
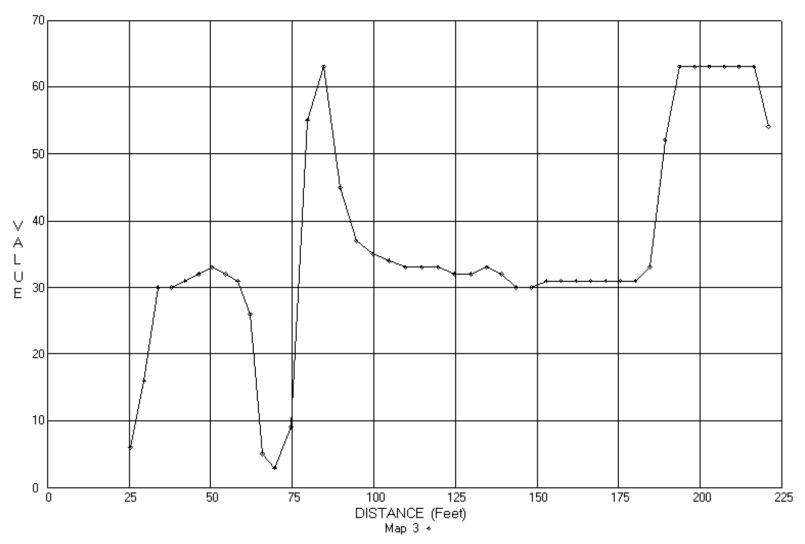
Re-alarm due to Growing Leak

Monitoring Using Map 2 and Detection of Growing Leak

Monitoring of Wet Cable
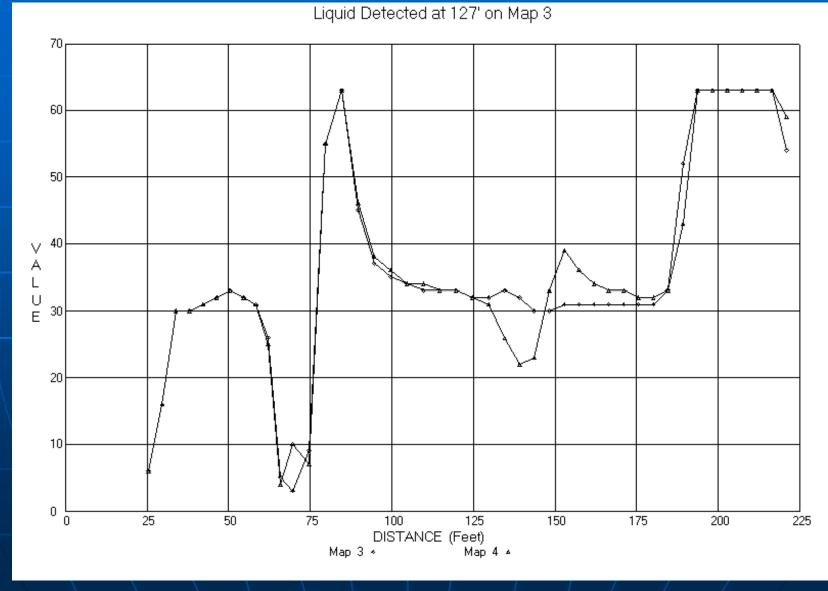
Monitoring Using Map3 with Liquid on the Cable
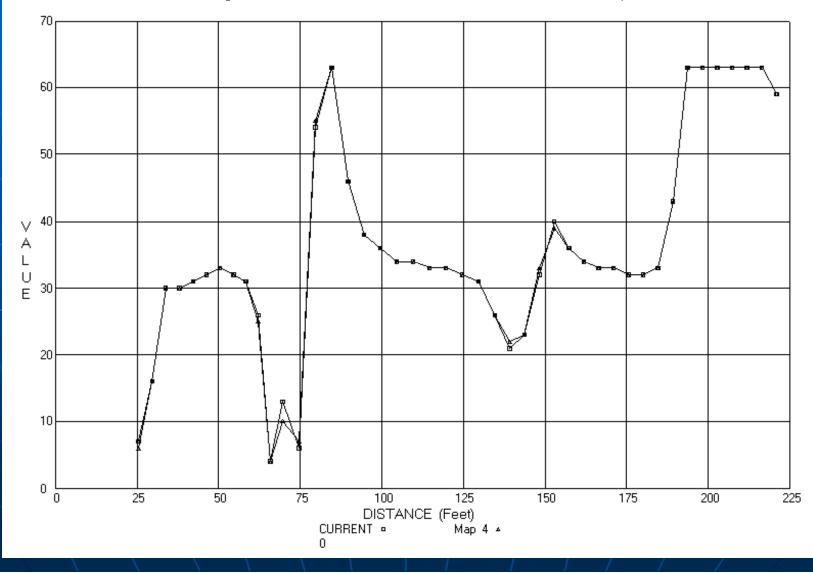
Detection of New Leak while Wet

Liquid Detected at 127' on Map 3
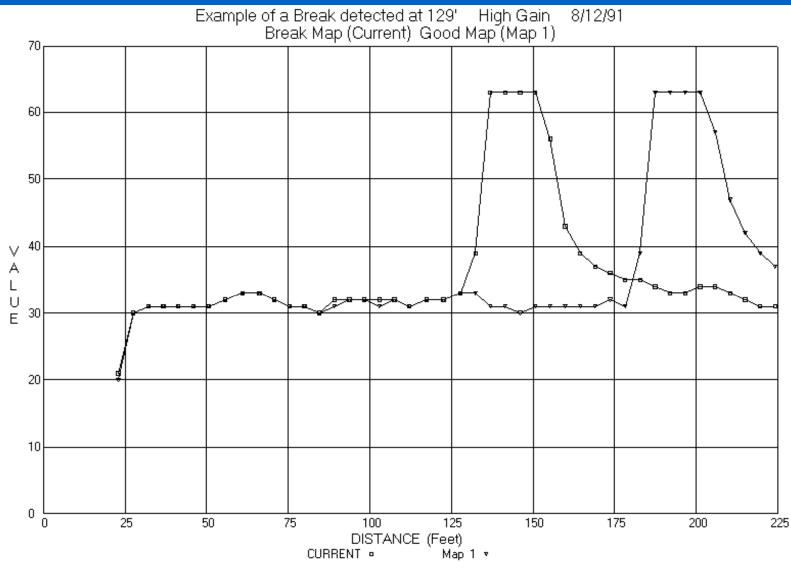
Monitoring of Cable
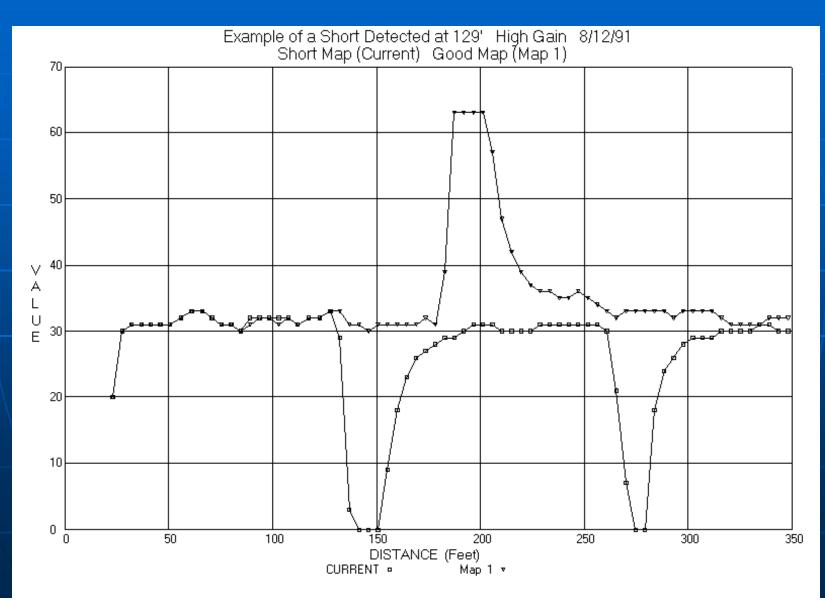
Monitoring a Cable with two wet locations (condensation, minor spills, etc.)

Break Detected and Located

Example of a Break detected at 129'   High Gain   8/12/91
Break Map (Current) Good Map (Map 1)

Short Detected and Located

Example of a Short Detected at 129'   High Gain   8/12/91
Short Map (Current)   Good Map (Map 1)

PAL-AT Panels
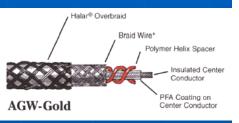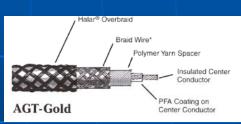
- AT20C - Monitoring up to 2,000' (600 m) on a single cable
- AT50C - Monitoring up to 5,000' (1500 m) equivalent length on a single cable
- AT20K - Monitoring up to 7,500' (2500 m) equivalent length per cable with a maximum of two cables
- AT40K - Monitoring up to 5,000' (1500m) equivalent length per cable with a maximum of eight cables
- AT80K - Monitoring up to 7,500' (2500 m) equivalent length per cable with a maximum of eight cables

Types of Cable
PAL-AT

- AGW Gold Sensor cable for use in containment piping, trenches, tray and subfloors

- AGT Gold Sensor cable for use in subfloors and trays. More sensitive than AGW

- TFH Sensor cable for detecting hydrocarbons and solvents while ignoring water

AGW-Gold

AGT-Gold

■TFH

PermAlert
Environmental Specialty Products, Inc.
Liquid Leak Detection Systems
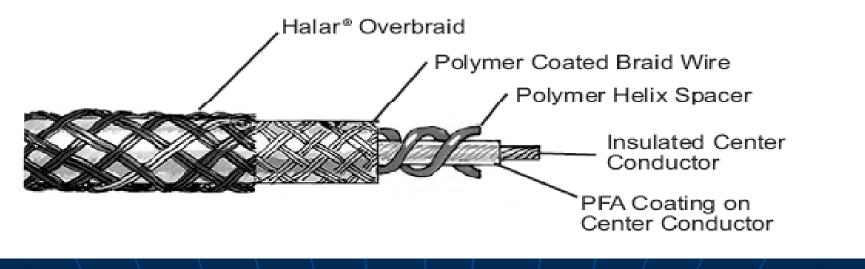
Sensor Cable Construction

AGW-Gold

AGW-Gold is a quick drying cable that is chemically resistant and designed to detect highly corrosive liquid leaks such as acids, bases and solvents. Typical applications are secondary contained pipes in chemical installations, subfloors of clean room manufacturing areas, computer rooms and high temperature applications such as steam pipe containment systems. The cable has passed UL 910 for Plenum Rating.

Halar® Overbraid
Polymer Coated Braid Wire
Polymer Helix Spacer
Insulated Center Conductor
PFA Coating on Center Conductor
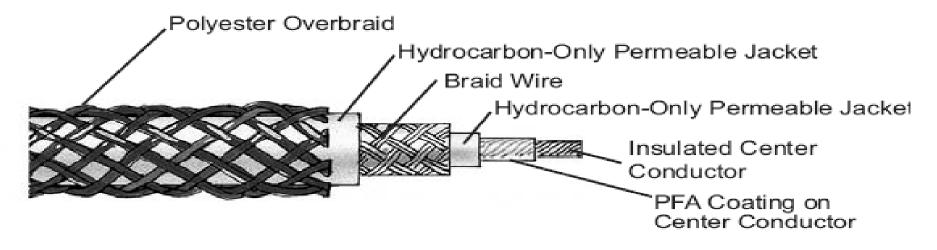
TFH Hydrocarbon Cable

TFH is a wicking cable specifically designed to detect only hydrocarbons. This cable may be direct buried to a maximum depth of 20 ft (6 m) to locate fuel leaks while ignoring the presence of water. This cable is ideal for monitoring single-wall pipes and tanks. In applications where hydrogen sulfide or other corrosive gases may be encountered, such as refineries and oil fields, cable life may be reduced.
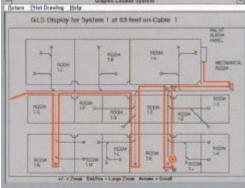

Polyester Overbraid
Hydrocarbon-Only Permeable Jacket
Braid Wire
Hydrocarbon-Only Permeable Jacket
Insulated Center Conductor
PFA Coating on Center Conductor

Benefits of TDR Technology

- EPA Third Party tested for 0.2 gph
- Wet cable startup
- Multiple Leak location capability
- Location of Breaks
- Detection of Shorts versus Leaks
- Not susceptible to contamination from dirt/dust, etc
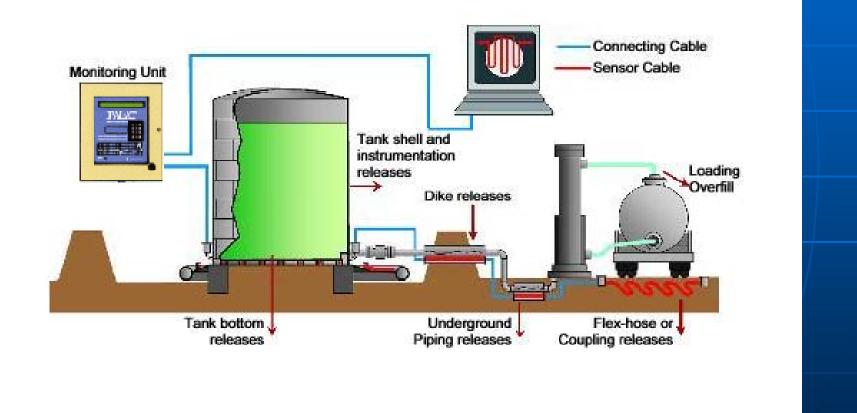
Palcom Software

- Palcom allows remote control of up to 254 panels with the ability to review TDR traces, review the history of each unit and to pull down a Cad drawing for each system for location of leaks, breaks, shorts or probe activation's.
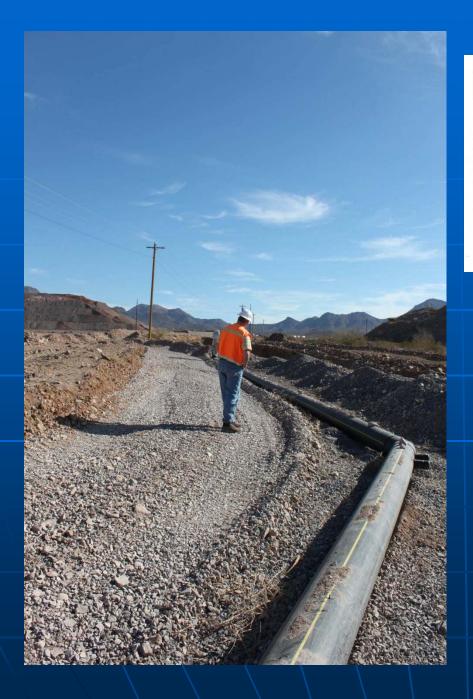
Oil Terminals

ULTRA-HT

Our Ultra-HT system is the most thermally efficient product offered for environmentally sensitive media, that must maintain a critical temperature. Ultra-HT can combine any type of steel alloy, for the inner and outer containment piping, that is best suited for your exact applications. A minimum of one inch thick polyurethane foam is first sprayed on to the containment pipe. The filament wound resin reinforced fiberglass is then directly applied to the insulation. This insulated outer pipe provides the necessary temperature maintenance required for your application.
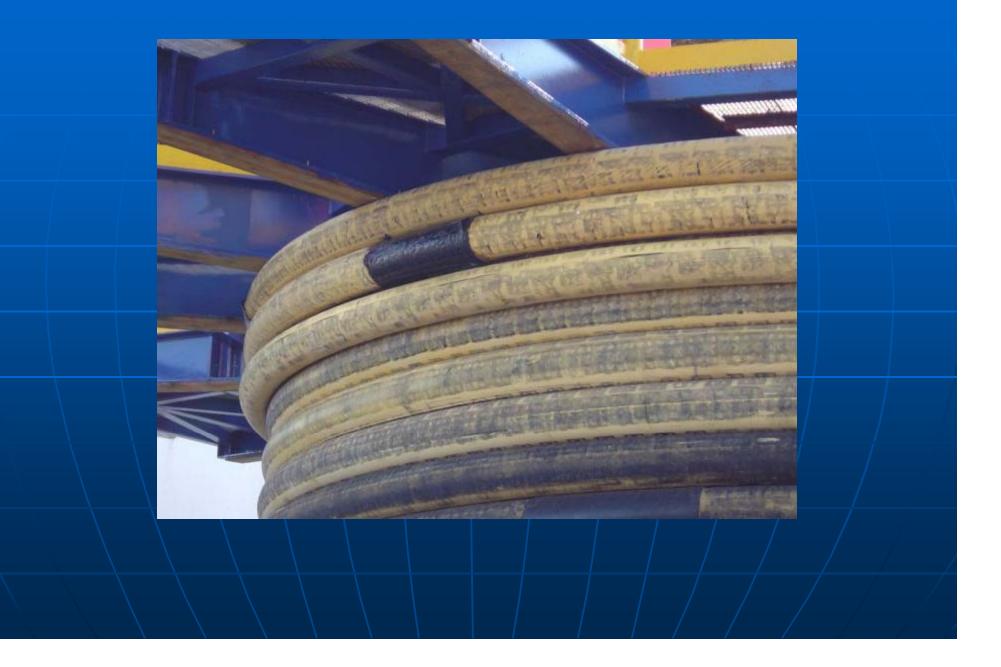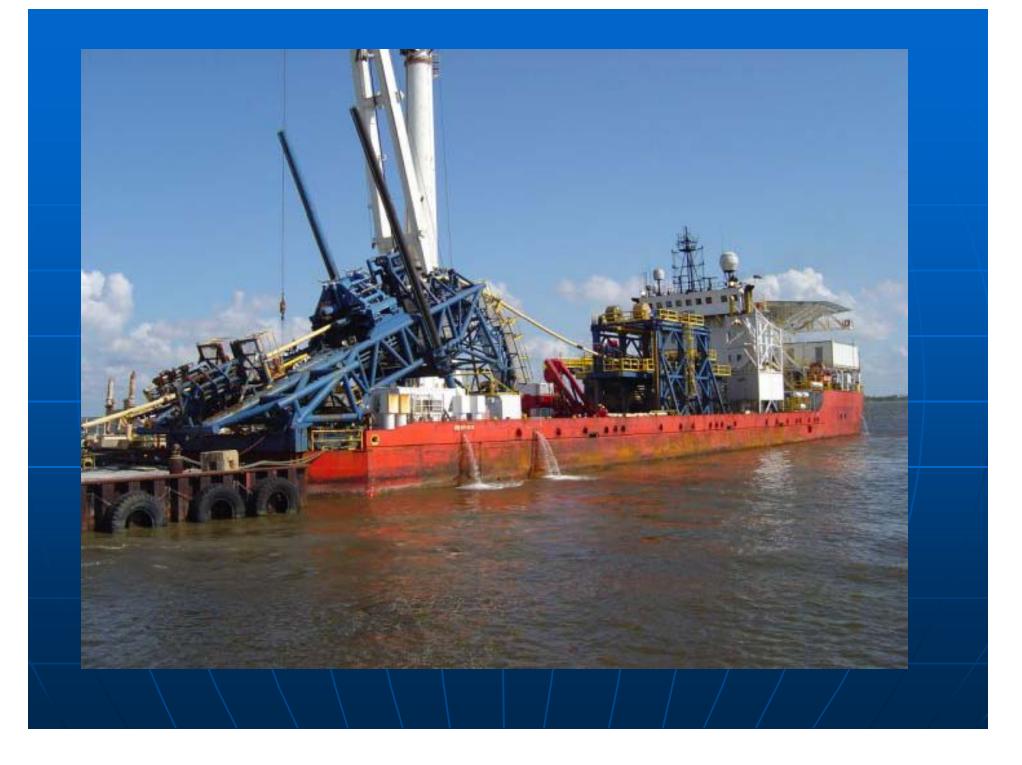
Qatar Gas Sulfur Line

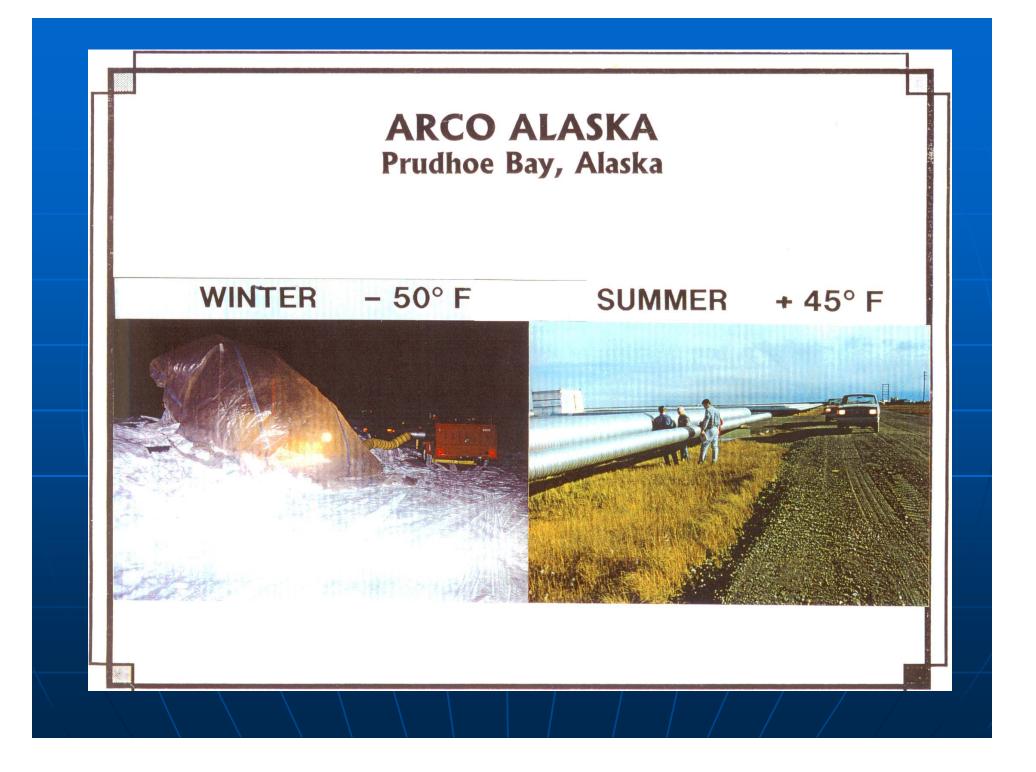# Polyurethane Bending Trial
Suitable for Reeling

ARCO ALASKA
Prudhoe Bay, Alaska

WINTER − 50° F   SUMMER + 45° F

Questions and Answer Period

Art Giesler
Director of Sales
8190 Precinct Line Road

Colleyville, TX 76034
art.giesler@permapipe.com
817-849-1998
cell 817-239-2234

APPENDIX L

OMNISENS SA - DITEST ANALYZER

Distributed Fiber Optic Sensing for Precision Pipeline Integrity Monitoring

Presented: Sept 14, 2011 Alaska DEC

Omnisens Background

omnisens
Securing asset integrity

◉ Privately-owned Swiss company, established in 2000

  ◉ *__Decade of application development__*

  ◉ *__Distributed Sensing__*

◉ Spin-off from Swiss Federal Institute of Technology in Lausanne

  ◉ *__Decade of technology development__*

  ◉ *__Stimulated Brillouin Scattering__*

◉ Headquarters in Morges, Switzerland

  ◉ Manufacturing, Service, Development

◉ Worldwide customer base

Dana DuToit
Omnisens
North American Manager
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dana.dutoit@omnisens.com
1244 Adrian Drive
Chaska, MN 55318
United States of America
www.omnisens.ch/ditest/

Omnisens' Enabling Technology

"DITEST" measuring units: Excite and Analyze Scattered Light

- **STA-R :** **Precision** Distributed Temperature and Strain Monitoring system
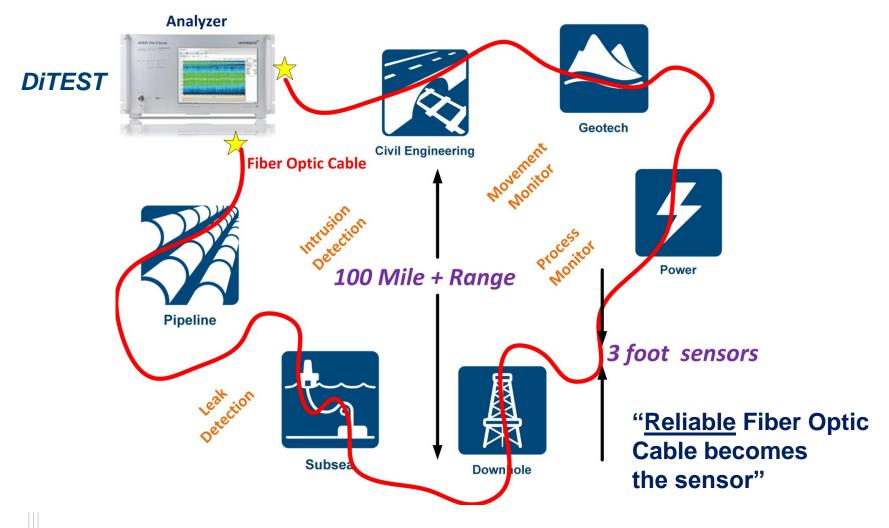- **D-LIGHT :** **Dynamic** Distributed Temperature and Strain Monitoring system

The Power of Distributed Sensing
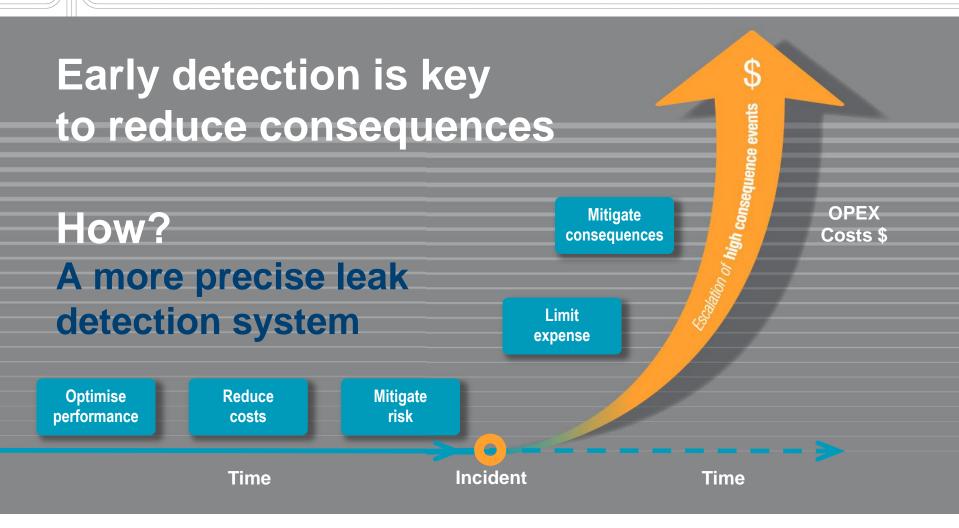
Integrity Monitoring

	Fly	Walk	Mass Balance	Omnisens
Long range	✔	✔	✔	✔
Submarine / terrain	✘	✘	✔	✔
Early Detection < 0.1% Flow	✘	✘	✘	✔
Continuous 24/7	✘	✘	✔	✔
Pinpoint accuracy localization	✔	✔	✘	✔
Retrofit Underground	✔	✔	✔	✘
No false alarms	✔	✘	✘	✔
Sensitivity	✘	✘	✘	✔
No Opex costs	✘	✘	✔	✔
Ground movement detection	✔	✔	✘	✔
Third party Intrusion detection	✘	✔	✘	✔

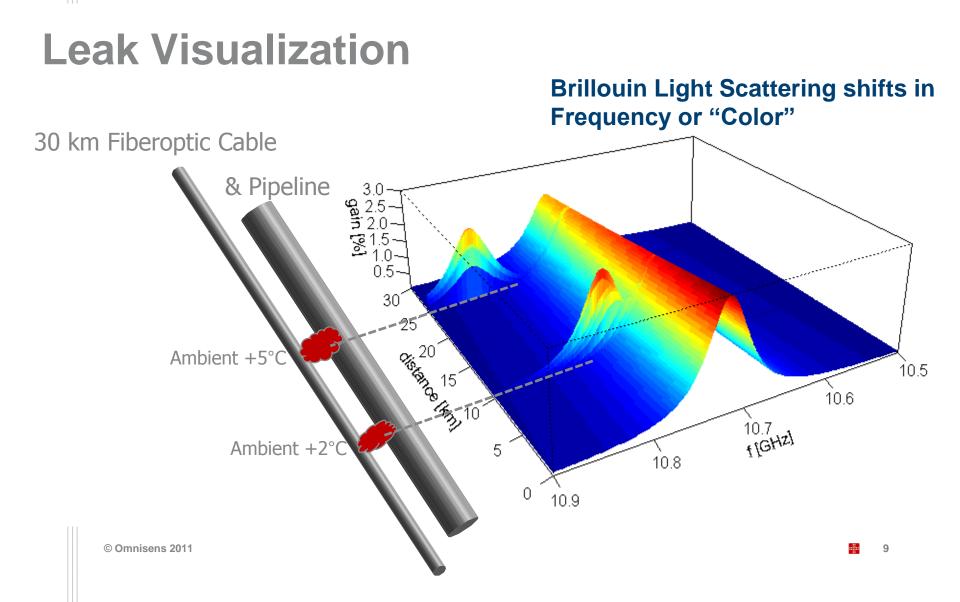## Advantages & Specifications Confirmed via PRCI Testing

Leak detection

- Leakages are associated to abnormal local temperature changes

- Omnisens DiTest system can excite and analyze 150,000 x 3 ft temperature sensors in less than 10 minutes

- Low loss – low cost optical cables provides economical low range coverage.

Leak Visualization

Brillouin Light Scattering shifts in Frequency or "Color"

30 km Fiberoptic Cable

& Pipeline

Ambient +5°C

Ambient +2°C

Leak detection cables

Pipeline

Leak Detection Cables are Communication Cables

- Temperature Monitoring Cables (TMC)
- Robust telecommunication cables
- Multiple <u>additional fibers for communication</u> purposes
- Compatible with direct burial or outside exposure
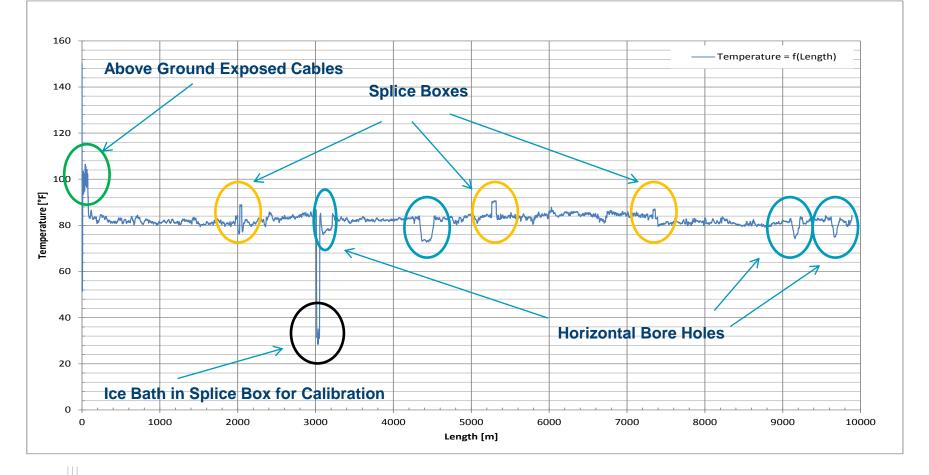- Availability of <u>Artic Rated</u> cables.

Temperature Profiles

omnisens
Securing asset integrity

Pipeline

Above Ground Pipeline Temp Profile
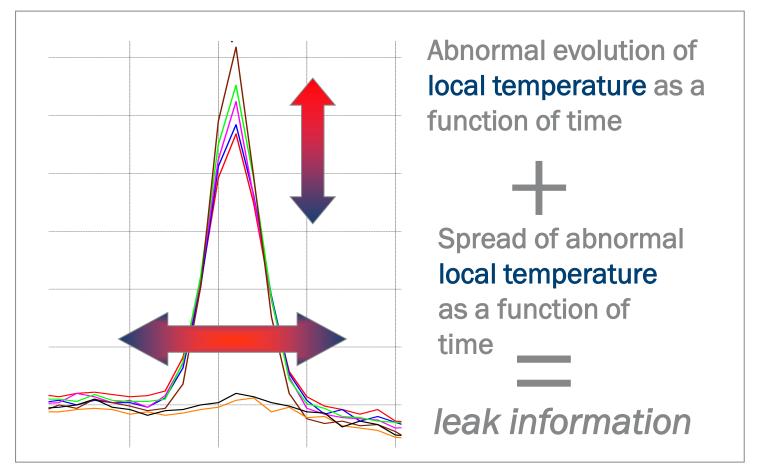
Evolution of a Leak Event - Summary

Abnormal evolution of **local temperature** as a function of time

+

Spread of abnormal **local temperature** as a function of time

=

leak information
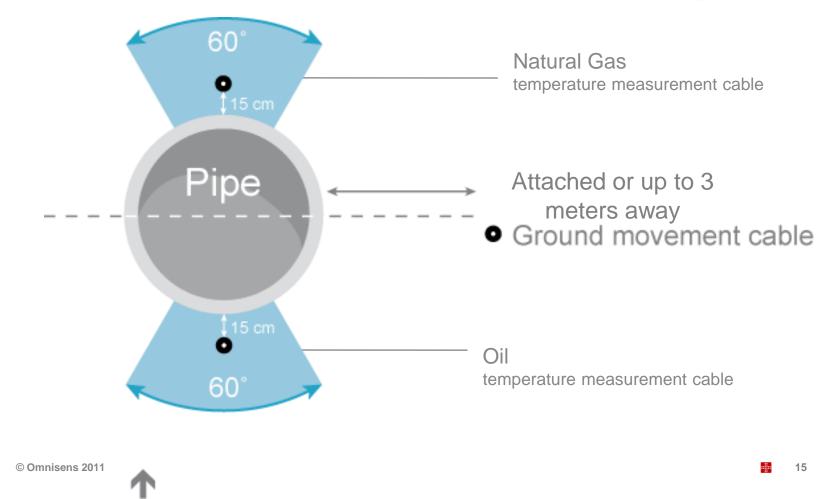
Leak detection and localisation

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Pipeline

Liquid phase pipeline
Leakage = hot spot

Compressed Gas pipeline
Leakage = cold spot
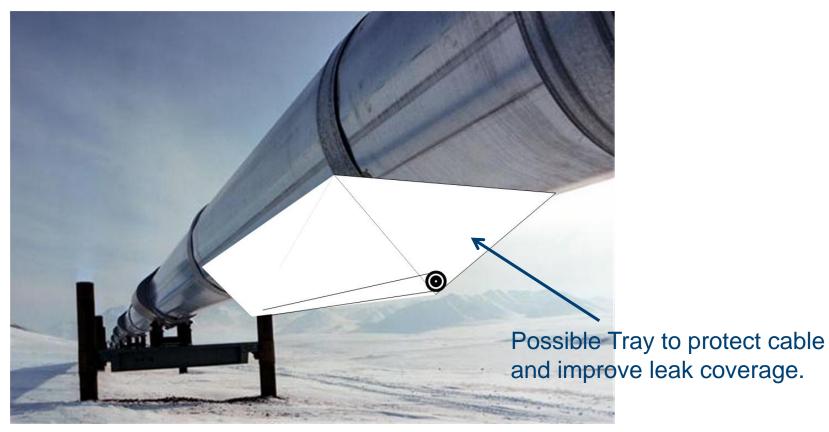
Fiber Optic Sensor cable positioning

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Retrofit/New Construction Cable Position

Possible Tray to protect cable
and improve leak coverage.
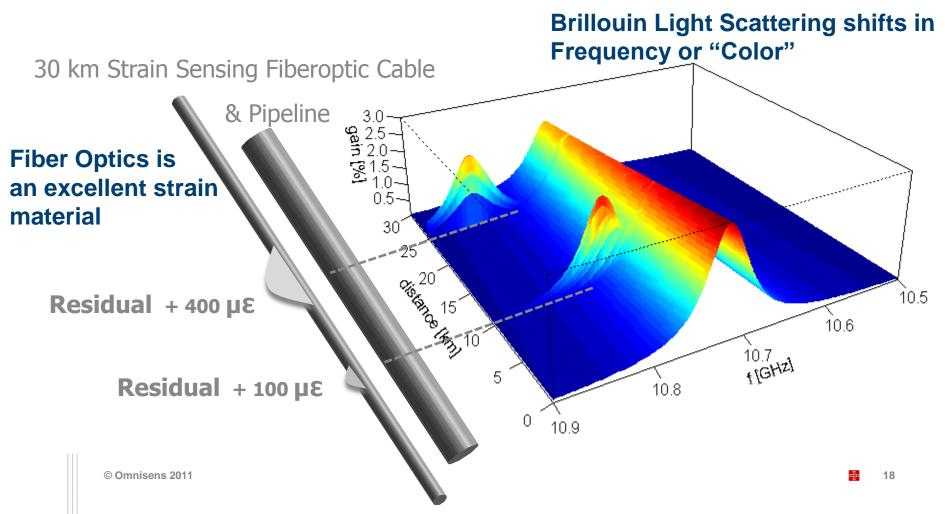
Artic Pipeline Ground Movement Monitoring

Subsidence Monitoring
Permafrost Heaving
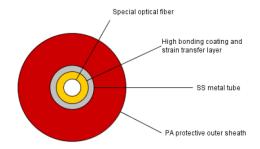
Movement or Subsidence Visualization

Brillouin Light Scattering shifts in Frequency or "Color"

30 km Strain Sensing Fiberoptic Cable

& Pipeline

Fiber Optics is an excellent strain material

Residual + 400 µε

Residual + 100 µε

Ground movement detection

Strain Fiber Optic Sensors – SMC Series

◎ Designed for DITEST-AIM fiber optic distributed sensing applications

  ◉ Application: Ground movement, landslides, soil subsidence, …

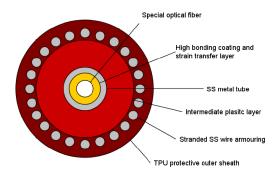◎ Mechanically reinforced design with stranded stainless steel wires and abrasion resistant protective sheath

  ◉ Easy and rapid installation

◎ Robust design and excellent rodent protection, ideal for direct burial applications

  ◉ Compatible with direct burial

Special optical fiber

High bonding coating and strain transfer layer

SS metal tube

PA protective outer sheath

Special optical fiber

High bonding coating and strain transfer layer

SS metal tube

Intermediate plasitc layer

Stranded SS wire armouring

TPU protective outer sheath

How's my time?

Technology

Product Sets

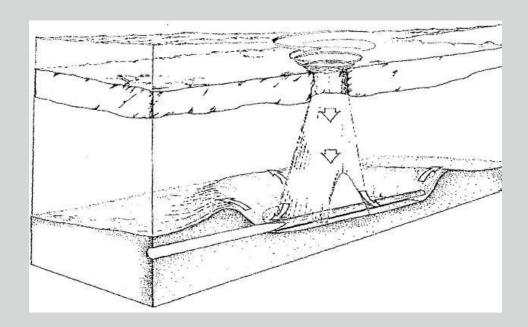**Selected Case Studies**

Case study: Oooguruk Field

Case study Oooguruk

Challenge
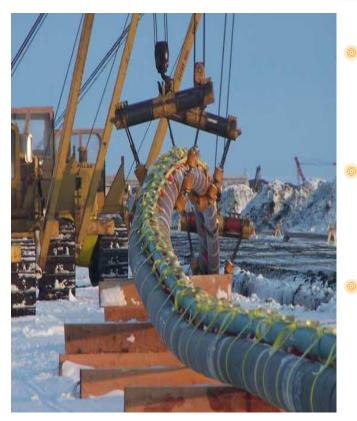
- River flows in summer time and strudel scour

- Seabed erosion due to currents and water jets

- Risk of ice gouging and/or heaving/buckling of pipeline

Case study Ooooguruck

Solution

- Distributed temperature monitoring system along the 13km flow line bundle via fiber optic cable for the detection of erosion event.

- DITEST STA102 selected
  - 2m spatial resolution
  - < 0.5C temperature accuracy

- System commissioned in 2007

Case study Ooooguruk

Results

Example 2: Fiber 1 Near Flowline - Alarm 1 and Alarm 2
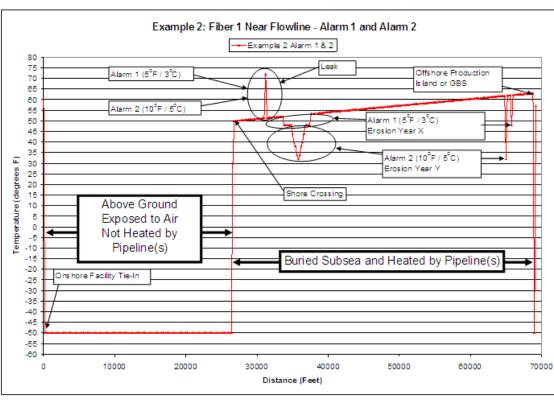
Erosion and Leak events modeled in attached graph.

In 2007 – 33 erosion events were identified spatially and dimensionally. Confirmed by sonar. 6 were mitigated.

In subsequent years – a smaller number of erosion events were accurately identified.

No Leak events recorded

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Similar to the Oooguruk Application

Fiber Optic Monitoring to be commissioned shortly

ENI has commissioned portions of the Nikaitchuq field.

1) Temperature monitoring of buried subsea flow line bundle from artificial island 3.5 miles offshore.

2) Temperature monitoring of power cable bundle in separate trench.

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Challenge

Leakage detection on a 55 Km brine pipeline
Brine Temp was 38C/30C Ground temp 5C

Case study Berlin Brine Pipeline

Solution
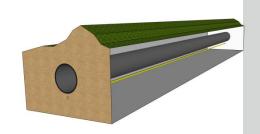
○ One fibre-optic cable was buried in the trench below the pipeline throughout its length. For Leak Detection and Communication.
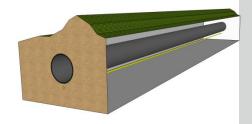
○ Two DITEST interrogators were installed at 15 Km and 45Km.

○ The DITEST interrogators can detect a leak in less than 10 minutes with 1°C accuracy along 55 Km.

Case study Berlin Brine Pipeline

Results

- In July 2003, a leakage was detected by the monitoring system.

- The local temperature increase due to the leakage is measured to be > 3C/Min and spread of >0.5 meters/min.

- An alarm was immediately and automatically triggered and the flow was stopped.

- Accurate location of the leak to within 1 meter.

Case study Berlin Brine Pipeline

Results
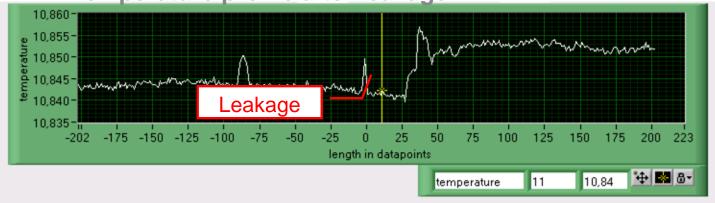
Temperature profile before leakage

Temperature profile after leakage

Leakage

Case study Peru LNG

Challenge

Liquid natural gas pipeline operated by Peru LNG stretching over 408 km of harsh terrain in the Peruvian Andes.

Need of long-range, continuous monitoring to prevent ground movements and landslides affect the integrity of the pipeline.

Challenge
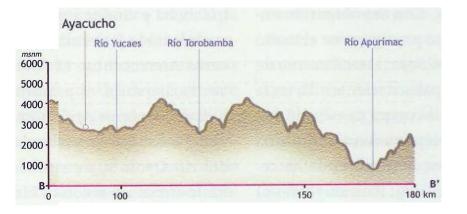
Pipeline crosses unstable regions with challenging climate:

- Steep slopes, high peaks, deep valleys
- Climate from warm humid to cold temperate with heavy precipitations at rainy season
- The remote location meant visual inspection was impractical.

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PERU LNG
Melchorita

Solution

HUNT
OIL COMPANY
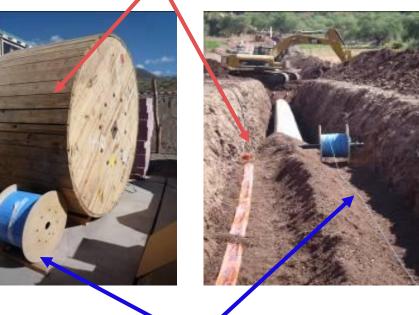
Leak detection

- ◎ Temp/LDS OFC Optical Fiber cable
- ◎ Designed to measure leaks by temperature difference in the soil
- ◎ 10 Single mode fibers,
- ◎ Telecom type cable

Ground Movement
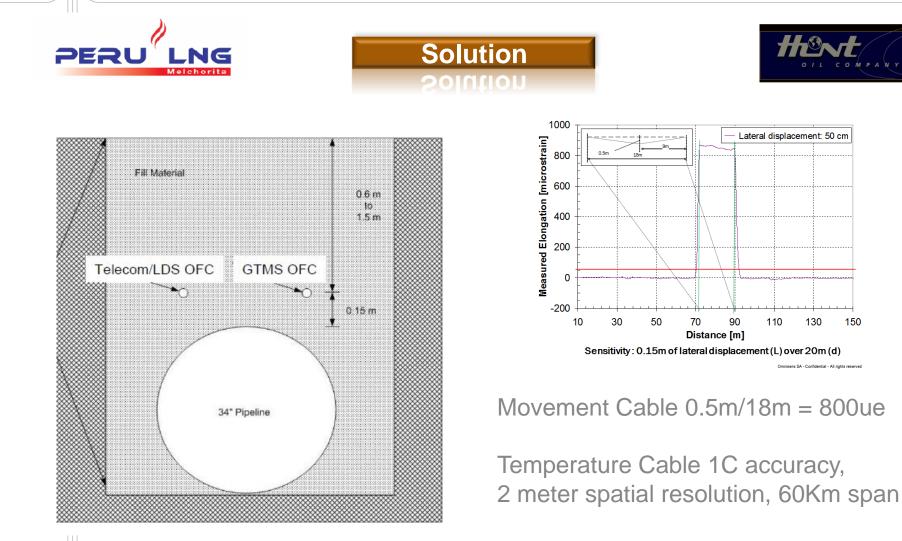
- ◎ GTMS OFC Optical Fiber Cable
- ◎ Designed to measure lateral and longitudinal ground movement around the pipeline and anticipate pipeline strain

Telecom / temperature cable

Strain cable

Case study Peru LNG

Solution

Fill Material

0.6 m to 1.5 m

Telecom/LDS OFC   GTMS OFC

0.15 m

34" Pipeline

Sensitivity : 0.15m of lateral displacement (L) over 20m (d)

Movement Cable 0.5m/18m = 800ue

Temperature Cable 1C accuracy,
2 meter spatial resolution, 60Km span

Case study Peru LNG

Solution
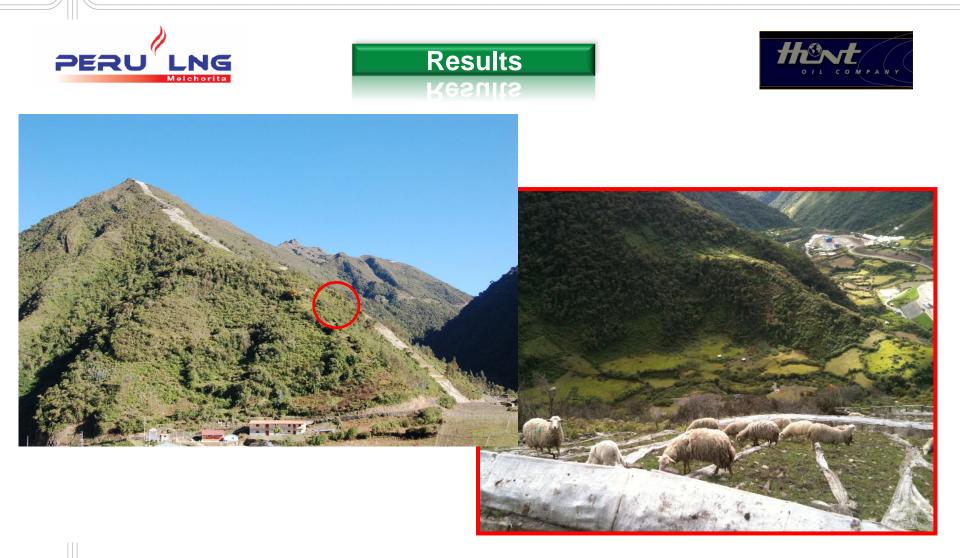
Cable installation coordinated with Pipeline construction

Training of local technical staff and supervision

Monitoring System Commissioned in 2009

Results

Case study Peru LNG

Results

High Stress region detected: Pipeline Strain Mitigated (2010)

Stress relief works

© Omnisens 2011

36

Case study Peru LNG

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Securing asset integrity

Results
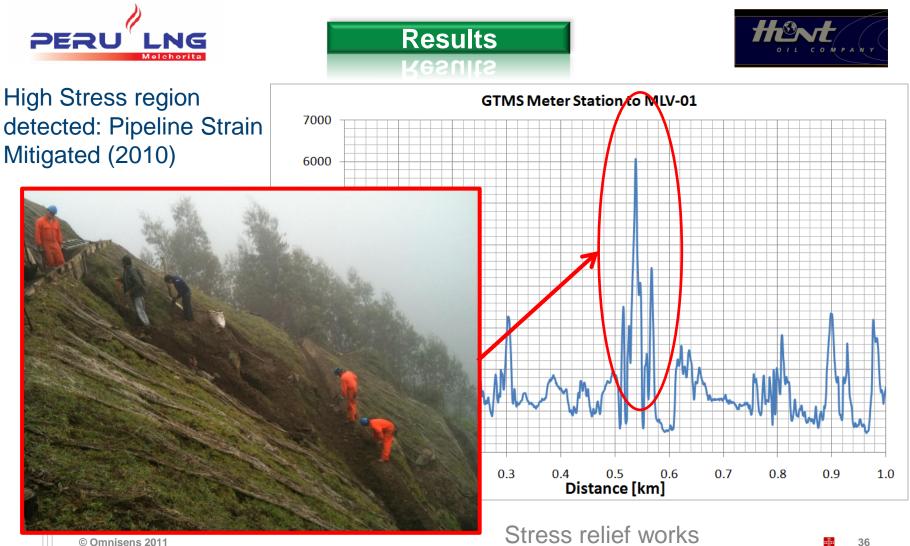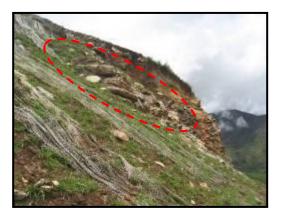
Soil movement, soil settlement due to rocks that had fallen at KP27+900

2011 Subsidence detected (note permanent change) and mitigated at KP27+900 location

Case study Peru LNG

Results

Soil displacement at KP35

Legend:
- 18.02.2011 06:40
- 19.02.2011 23:21
- 20.02.2011 11:31
- 20.02.2011 23:13
- 21.02.2011 00:58

X-axis: Distance [m]
Y-axis: Strain [microstrain]

Visual inspection

2011, Strain evolution at KP35 noted. Correlates with Subsidence. Being monitored.

Case study Peru LNG

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Securing asset integrity

Results
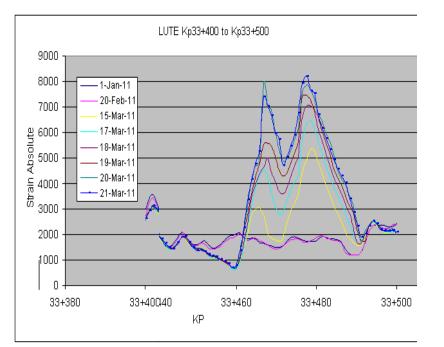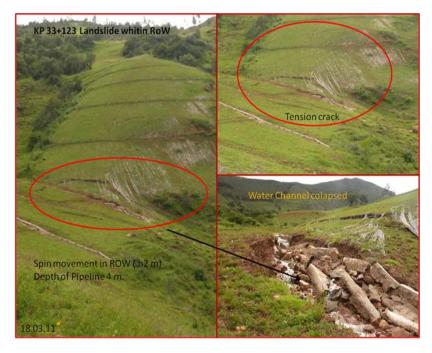
2011 - Near KP 33 – Tension Crack/Water– no damage to pipeline - monitored

Summary

10 + Pipeline Project worldwide (Monitoring since 2003)

100's of miles currently monitored

1000's of miles monitored by the end 2012 (Significant new projects)

-Modest volume of event statistics to report on to date

PRCI (Pipeline Research Council International) 3rd party tested

- Omnisens System specifications verified

At 40 mile range (20 miles both ways) 150ml/min leak @ 3F Delta T on 1ft exposed cable produced reliable leak detection in < 2 minutes

equates to 0.001% leak rate on 100,000 BPD pipeline

Leak detection system can be leveraged into movement/intrusion sensing and offers a high bandwidth communication path.

PIPELINE CHARACTERISTIC	PIPELINE CONFIGURATIONS					
	A	B	C	D	E	F
Location	North Slope	North Slope	North Slope	North Slope	Cook Inlet	Cook Inlet
Type	Transmission	Transmission	Flowline	Flowline	Transmission	Flowline
Total Length (miles)	40	25	4	8	40	9
Length Aboveground (miles)	40	24	4	2.5	0	0.5
Length Underground (miles)	0	1	0	0	40	0
Length Subsea (miles)	0	0	0	5.5	0	8.5
Diameter (inches)	24	12	28	12/16 pipe-n-pipe	20	8
Daily Production						
Crude Oil [barrels per day (bpd)]	150,000	1,400	10,000	15,000	23,000	3,000
Produced Water (bpd)	0	0	125,000	15,000	0	4,000
Natural Gas (million standard cubic feet of gas)	0	0	250	20	0	600
Typical Input and Output Parameters Measured						
Flow (bopd)	150,000	1,400	10,000	15,000	23,000	3,000
Pressure [pounds per square inch (psi)]	1200 to 1800	125 to 1400	100 to 600	100 to 600	100 to 125	100 to 600
Temperature [degrees Fahrenheit (ºF)]	100 to 180	100 to 180	90 to 110	90 to 120	100 to 140	90 to 110
Insulation Thickness (inches)	2.5	2	3	3	0	0
Ambient Air Temperature Range (ºF)	-62 to 83	-62 to 83	-62 to 83	-62 to 83	-38 to 82	-38 to 82

Precision Pipeline Integrity Monitoring for Economic and Environmental benefit

Thank you!

APPENDIX M

SCHLUMBERGER OILFIELD SERVICES – INTEGRITI PIPELINE MONITORING SYSTEM

Pipeline Integrity Monitoring

Multi-Measurement For Enhanced Protection & Mitigation
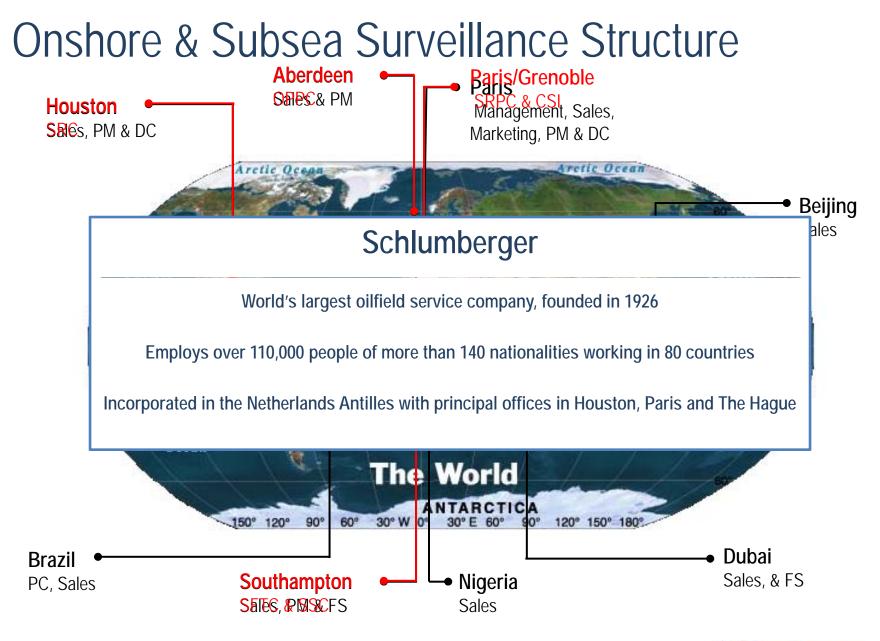
Alex Albert, Alastair Pickburn

ADEC 2011 Pipeline Leak Detection Technology Conference

Anchorage, Sep 13 -14, 2011

Schlumberger

Agenda
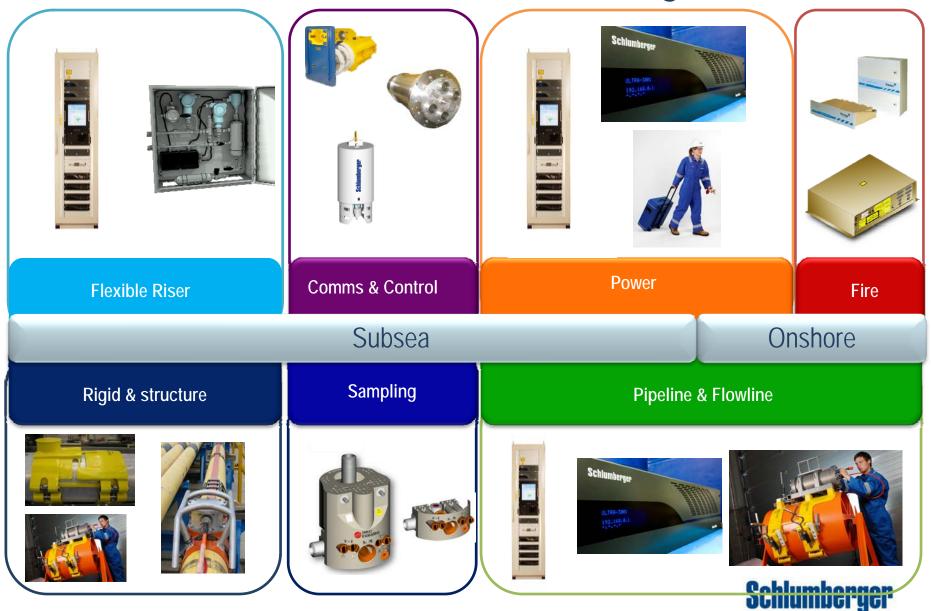
- Introduction to Schlumberger

- Pipeline Integrity - Voice of the Customer

- Distributed Optical Fibre Monitoring

  – Technology and Principles

- Case Studies

- Conclusions

Schlumberger

Onshore & Subsea Surveillance Structure

Aberdeen
SRPC & PM
Sales & PM

Paris/Grenoble
SRPC & CSL
Paris
Management, Sales,
Marketing, PM & DC

Houston
SRPC
Sales, PM & DC

Beijing
Sales

Schlumberger

World's largest oilfield service company, founded in 1926

Employs over 110,000 people of more than 140 nationalities working in 80 countries

Incorporated in the Netherlands Antilles with principal offices in Houston, Paris and The Hague

Brazil
PC, Sales

Southampton
STC, PM & CFS
Sales, PM &

Nigeria
Sales

Dubai
Sales, & FS

Schlumberger

Onshore & Subsea Surveillance Segmentations

| Flexible Riser | Comms & Control | Power | Fire |

| Subsea | Onshore |

| Rigid & structure | Sampling | Pipeline & Flowline |

Schlumberger

Onshore & Subsea Pipeline Integrity Issues
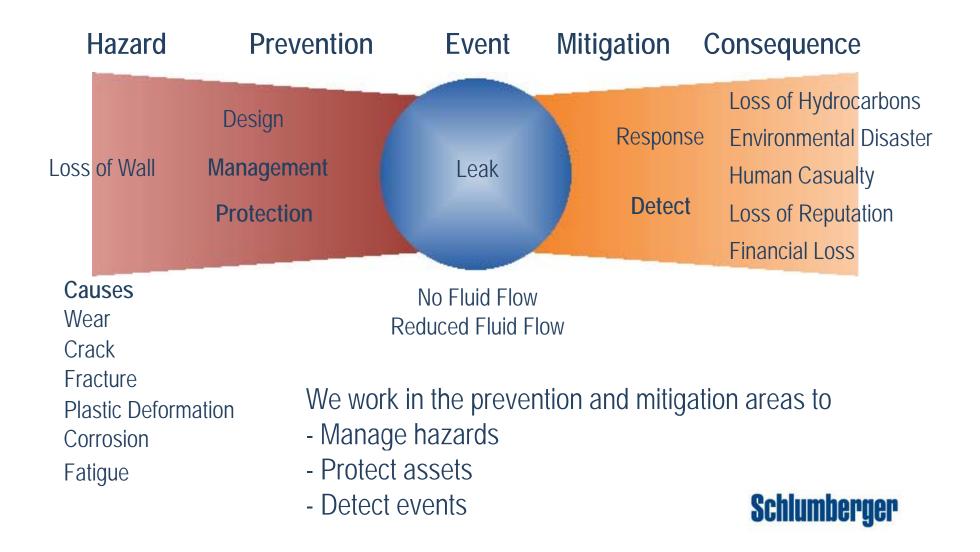
- Leaks & Ruptures
- Geo-hazards
  - Landslides & Subsidence
  - Permafrost Protection
  - Strudel & Ice Scour
- Intrusion Monitoring
- Pig tracking
- Heated Pipeline Monitoring
- Flow Assurance

Schlumberger
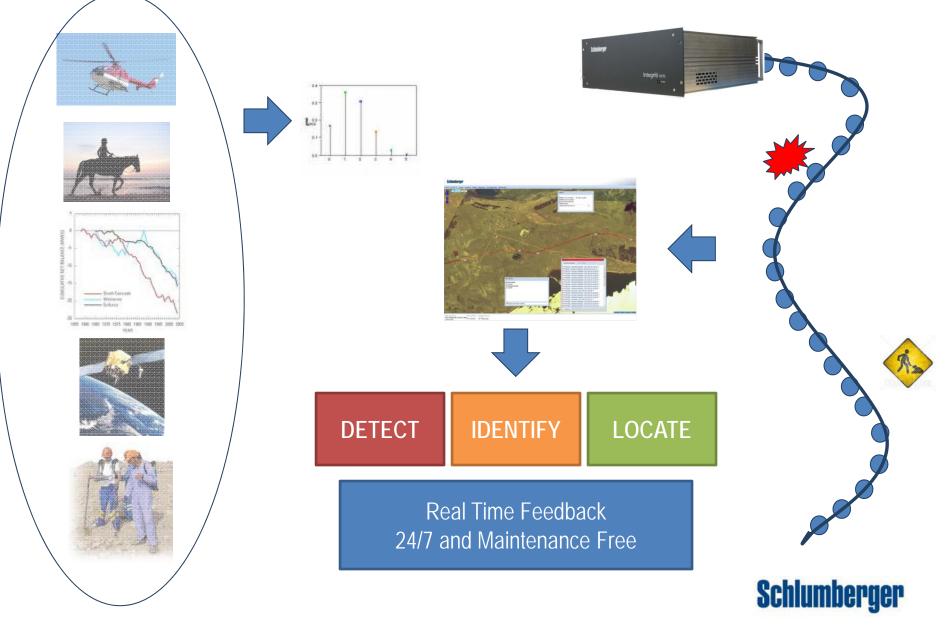
Controlling Hazards to Prevent Failure
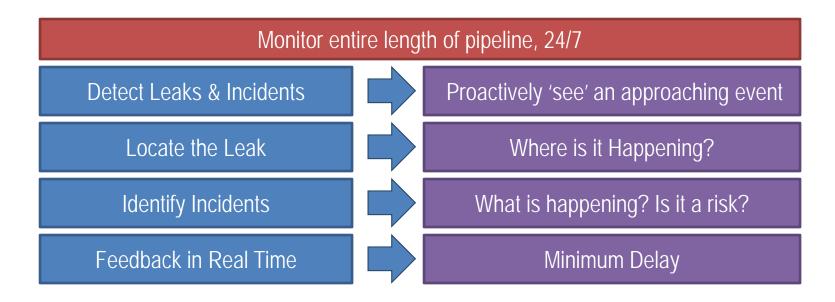
An example of a hazard, event and consequence using structural integrity to prevent or mitigate a leak
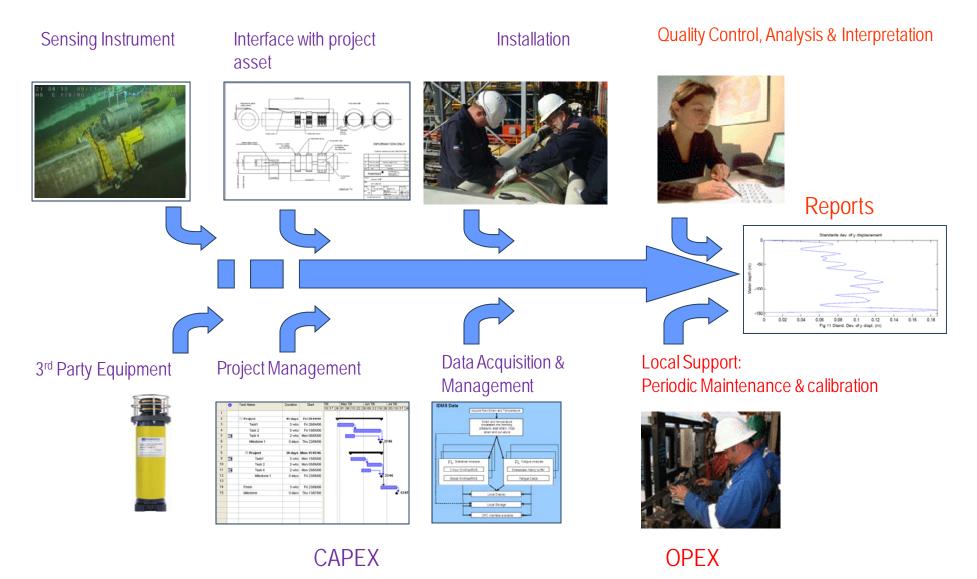
Hazard	Prevention	Event	Mitigation	Consequence

Design

Loss of Wall

Management

Leak

Protection

Response

Loss of Hydrocarbons

Environmental Disaster

Human Casualty

Detect

Loss of Reputation

Financial Loss

Causes
Wear
Crack
Fracture
Plastic Deformation
Corrosion
Fatigue

No Fluid Flow
Reduced Fluid Flow

We work in the prevention and mitigation areas to
- Manage hazards
- Protect assets
- Detect events

Schlumberger

What do we need?

DETECT   **IDENTIFY**   **LOCATE**

Real Time Feedback
24/7 and Maintenance Free

Schlumberger

Integrity Surveillance Systems – Focus on Data Quality

Sensing Instrument

Interface with project asset

Installation

Quality Control, Analysis & Interpretation

Reports

3rd Party Equipment

Project Management

Data Acquisition & Management

Local Support:
Periodic Maintenance & calibration

CAPEX

OPEX

Schlumberger

Integriti Platinum

Distributed temperature, strain and vibration measurements

- DSTS – Distributed Strain & Temperature Sensor

- DVS – Distributed Vibration Sensor

- DTS – Distributed Temperature Sensor

DSTS / DVS + DTS → Integriti Platinum → Actionable Information

Schlumberger

Fibre & Cables

- Use standard telecoms grade fibre
- Singlemode & Multimode fibres
- Retrofit on existing telecoms cable
- Intrinsically safe
- SLB qualified cable
  – Enables all measurements on single cable
    - Temperature
    - Strain
    - Vibration
- SS control line

Schlumberger
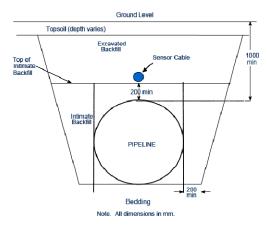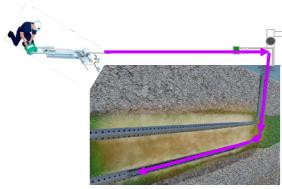
Install methods
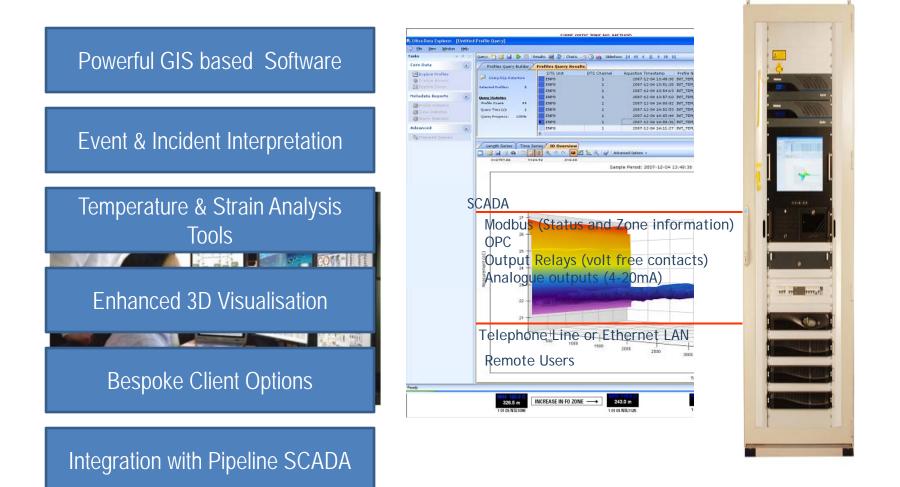
- Typically buried in pipeline trench

- Cable position dependent on application

- Retrofit & new construction

- Pipe in pipe installation

- SLB patented pumped deployment method

User Interfaces

Powerful GIS based Software

Event & Incident Interpretation

Temperature & Strain Analysis Tools

Enhanced 3D Visualisation

Bespoke Client Options

Integration with Pipeline SCADA

SCADA
Modbus (Status and Zone information)
OPC
Output Relays (volt free contacts)
Analogue outputs (4-20mA)

Telephone Line or Ethernet LAN

Remote Users

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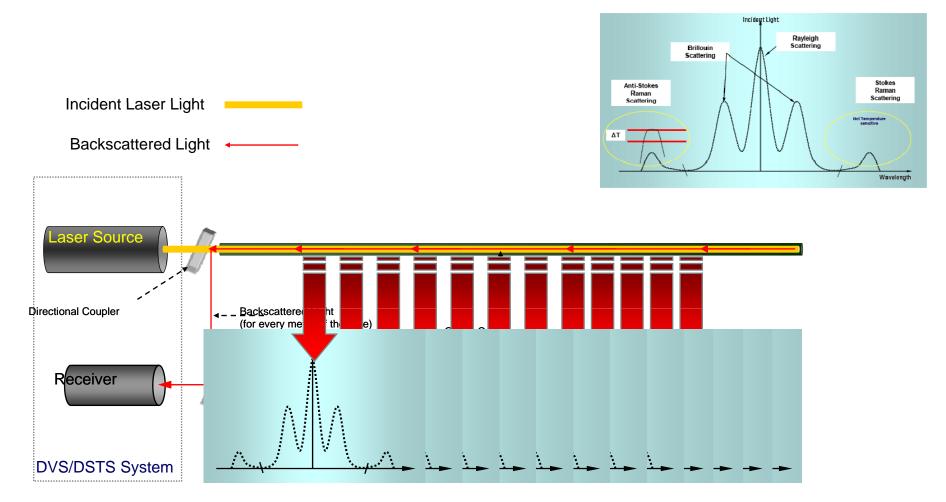
Pipeline Monitoring Principles

Gas Leaks	Oil Leaks	Third-Party Interference Pipeline Impact	Permafrost Protection	Ice & Strudel Scour	Ground Movement	Pipeline Strain
Joules Thomson Acoustic Vibration	Delta T Acoustic Vibration	Acoustic Vibration	Heat Trace Delta T Strain		Strain	
DTS DSTS DVS	DTS DSTS DVS	DVS	DTS DSTS		DSTS	

Theory of Operation

Incident Laser Light

Backscattered Light

Laser Source

Directional Coupler

Receiver

Backscattered Light
(for every meter of the file)

DVS/DSTS System

DVS/DSTS System installed in
Pipeline Control Room or
Pump/Compressor Station

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Concept of a Distributed Sensor
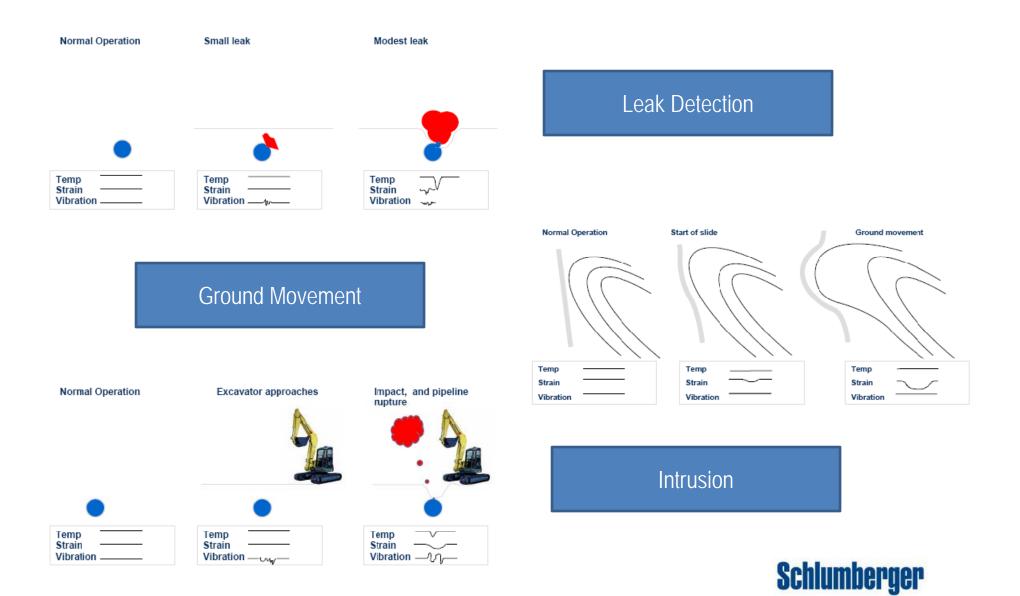
- Use optical fibre as the sensor - Optical Time Domain Reflectometry
- Monitor temperature, strain, vibration continuously along the fibre

Multiple Optical Techniques	
Brillouin OTDR – Temperature and Strain	DSTS –Distributed Strain and Temperature
Raman OTDR– Temperature	DTS ULTRA
Coherent Rayleigh Noise (CRN) – Vibration	DVS – Distributed Vibration Sensor

- Single sensing fibre (no return loop required)*
- ALL techniques immune to fibre breaks up to point of breakage

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Multiple Measurements

CASE STUDIES

Schlumberger
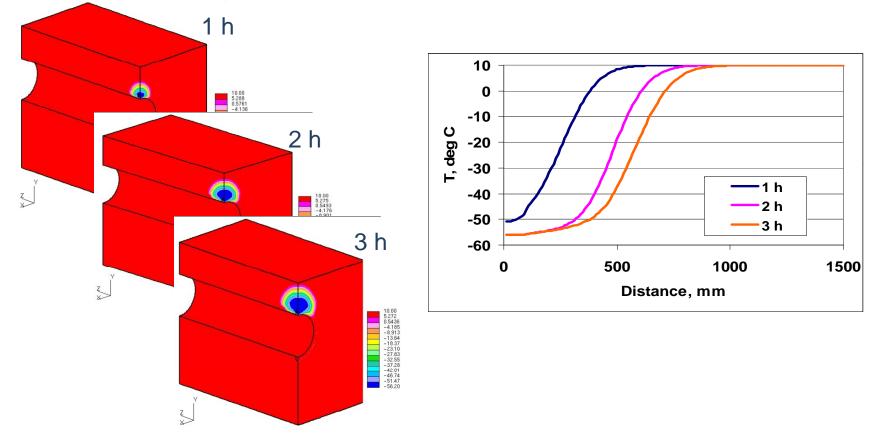
Gas Leaks - CFD Thermal Modelling
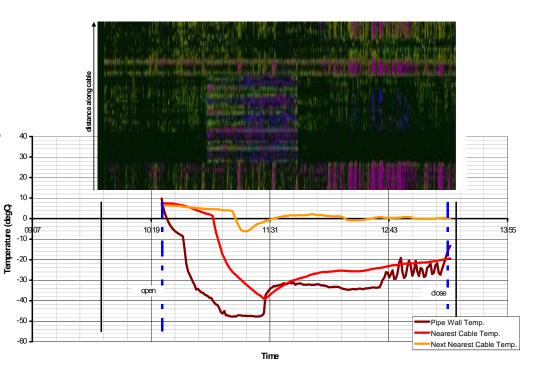
Simulated 3D temperature fields for 5 mm leak (mass flow rate approx 50 g/s)

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UK Full Scale Gas Release Testing

- 36″ diameter pipe

- 100barg pressure

- Natural gas

- 1mm / 2mm / 5mm leaks

- Different azimuths

- Results proved effectiveness of detection by temperature and vibration monitoring

- Validation of CFD modelling

Schlumberger
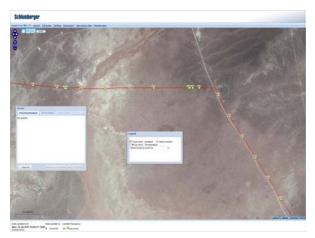
Gas Field Network Leak Detection System

- Middle East location

- Monitoring 20″ Flow line & 12″ Export line

- Total pipeline length of 70km

- Combined detection methodology
    - DVS - Acoustic (early warning)
    - DSTS – Temperature

- Optimised for fast leak warning with no vibration false alarms

- Leak confirmation from ground temperature anomaly detection

Schlumberger

BTC Georgia Pipeline

- **Challenges**
  - 100km section of Central Asian pipeline
  - Monitored TPI & Pig tracking
  - Remote region of Georgia
- **Solutions**
  - DVS + 3 stages of optical amplification
  - Web-enabled GUI remote from Integriti hardware
- **Key Lessons Learned**
  - Cars detected at up to 50m from buried cable
  - System utilised for fibre cable troubleshooting
  - Pigs tracked in real time
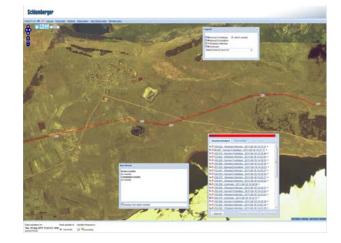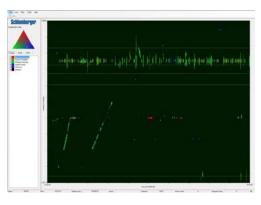
Schlumberger
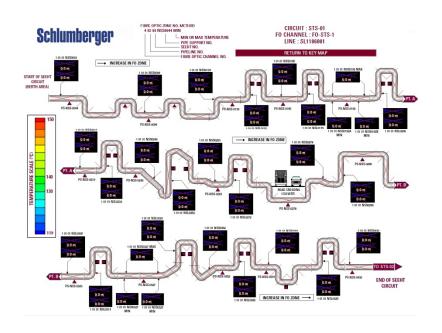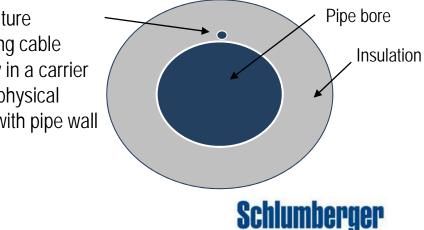
Case Study – Sulphur Pipe Monitoring

- Middle East Sulphur Project

- 40km of skin effect heated 12″ sulphur pipeline

- One DTS instrument (central location)

- Monitoring of maximum & minimum temperatures to ensure temperature stays in operating range

- GUI displayed on remote screen in control room
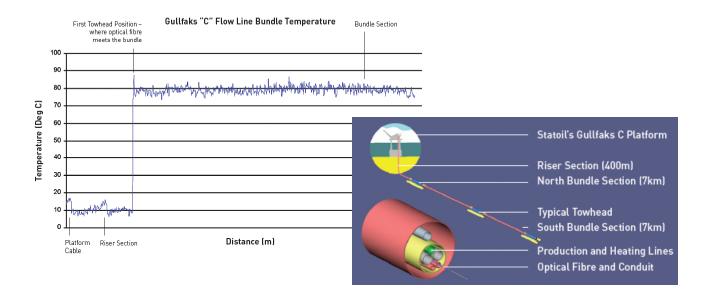
Temperature monitoring cable (typically in a carrier tube) in physical contact with pipe wall

Pipe bore

Insulation

Statoil Gullfaks C – Temperature Monitoring

- Monitoring of entire 14km length of water-heated production lines

- DTS control of heating for prevention of waxes & hydrate formation

Gullfaks "C" Flow Line Bundle Temperature

First Towhead Position – where optical fibre meets the bundle

Bundle Section

Temperature (Deg C)

Distance (m)

Platform Cable

Riser Section

Statoil's Gullfaks C Platform

Riser Section (400m)
North Bundle Section (7km)

Typical Towhead
South Bundle Section (7km)

Production and Heating Lines
Optical Fibre and Conduit

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Summary & Conclusions

- Integrated solutions designed specifically for continuous monitoring of onshore & offshore hydrocarbon pipelines:

- **Family of solutions** designed specifically for hydrocarbon pipelines and asset monitoring
- Up to **200km range all-optical** real-time condition monitoring per system
- Third Party Interference
- Leak detection
- Geohazard detection
- Pig tracking solution for pipelines with existing optical cables
- Temperature monitoring of heated pipelines,
- Operation in **all weather conditions, 24/7**;
- Reduces HSE risks
- Event recognition – minimises false alarms

- *Potential for significant impact on design & risk aspects of pipeline projects, and cost-reduction in construction of new pipelines*
- *Comprehensive hazard warning system: operating risk reduction for pipelines – enables operators potentially to prevent rather than react to leaks & events*

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Thank You!

Alex Albert

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713-703-6013 (Cell)
aalbert@slb.com

Schlumberger

APPENDIX N

PCE PACIFIC INC. – SMART WIRELESS AND WIRELESSHART

Smart Wireless Solutions

EMERSON™
Process Management

IEC 62591 (WirelessHART®) Meets the Requirements of Process Users

✓ **<u>Proven Interoperability</u>**

- Plug and play; Nothing to configure

- NAMUR Field Test confirmed device interoperability

  - Test included 40 WirelessHART products from six vendors: ABB, Emerson, Endress+Hauser, MACTek, Pepperl+Fuchs, and Siemens

✓ **<u>Robust Security</u>**

- WirelessHART security provisioning is inherently <u>standard and secure</u>, using wired HART interface

- Security is built in and is always ON

- Robust security demonstrated in hundreds of process industry installations
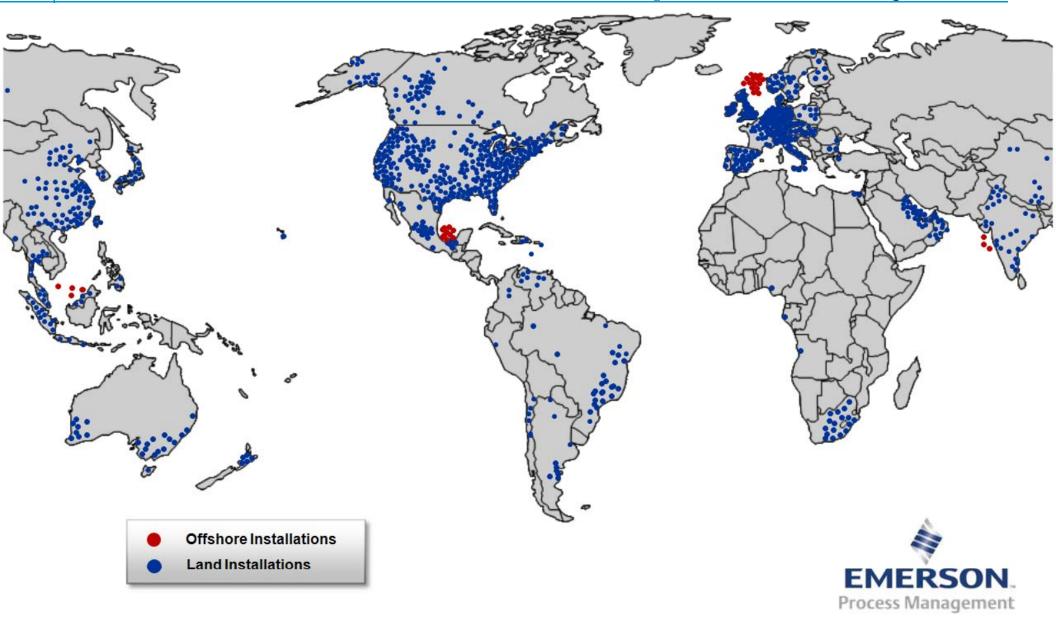
✓ **<u>Global Standard</u>**

- An IEC standard-IEC 62591 (unanimously approved March 26, 2010)

Emerson Smart Wireless Adopted Globally

Offshore Installations
Land Installations
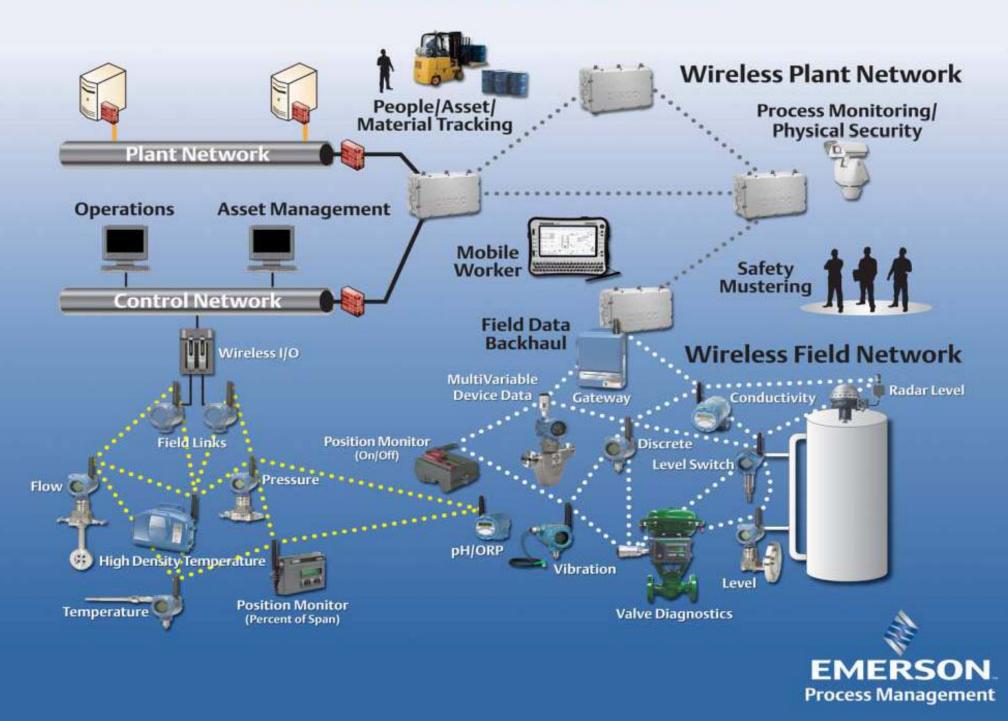
Smart Wireless solutions started shipping in 2007.

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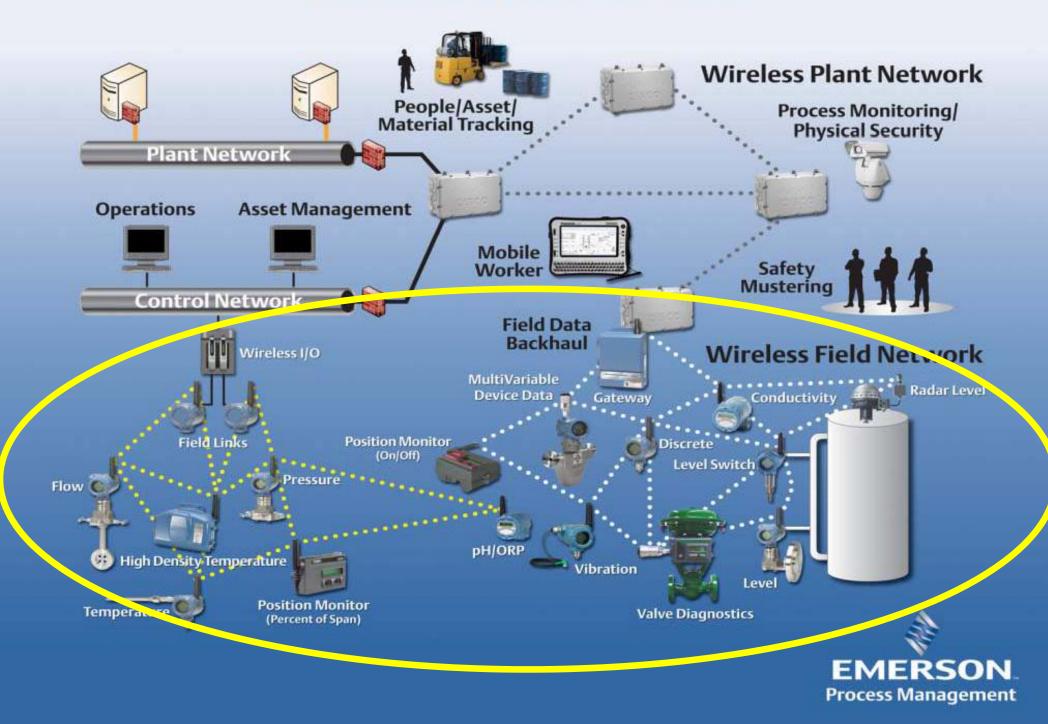
Global Customers Are Realizing The Benefits of Wireless.   5100 installations worldwide.
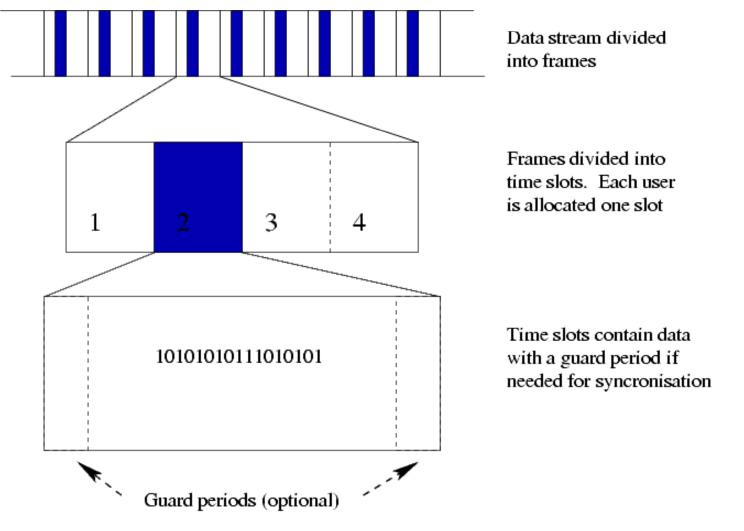
Time

- TDMA (Time Division Multiple Access)

- TSMP (Time Synchronized Mesh Protocol)

- Each node is time synchronized with the gateway and with each other

- Synchronization capability between devices is <1ms

- Bandwidth is added and removed at will

- Each node knows when to 'wake up'

- Duty cycle less than 1%

- Data are time stamped and easily correlated

Time Division Multiple Access

Data stream divided into frames

Frames divided into time slots. Each user is allocated one slot

1 2 3 4

1010101011010101

Time slots contain data with a guard period if needed for syncronisation

Guard periods (optional)

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Slot Time

Start Slot Assessment — **Switch to Transmit** — **Wait for ack** — **Receive ack**

Listen CCA — **Message 3 to 4 msec** — **Switch to receive**

← 10 msec - 1 time slot - 1 channel →

1 slot can transmit up to 8 PV's plus status

Packet = 133 bytes

250kbit/s

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Frame Structure adds Temporal Diversity
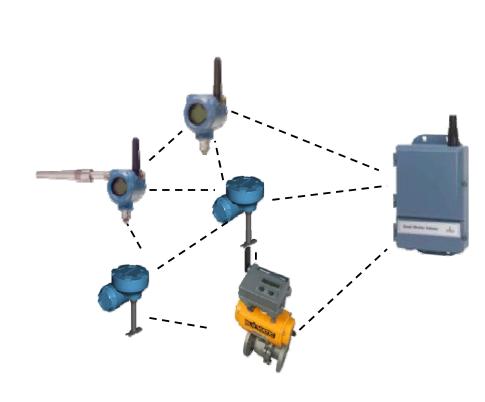
Frequency + Time Diversity = Bandwidth

2.483 GHz

Frequency

A2B   C2D

B2C

2.4 GHz

Time

A2B2C2D

WirelessHart Architecture and Integration are Simple

Modbus RTU
Modbus TCP/IP
OPC
DeltaV – Native I/O
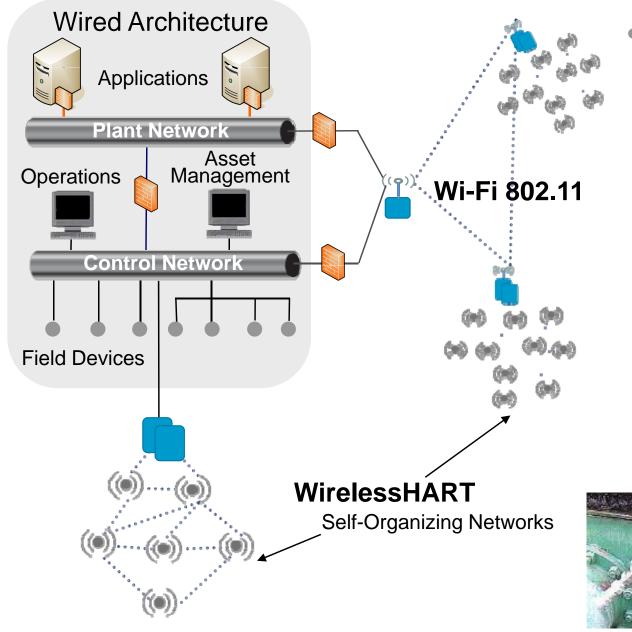
WAFN – Wide Area Field Network

Field Data BackHaul:
Bringing Wireless Field Data Back to Host

Wired Architecture

Applications

Plant Network

Operations

Asset Management

Control Network

Field Devices

Wi-Fi 802.11

WirelessHART
Self-Organizing Networks
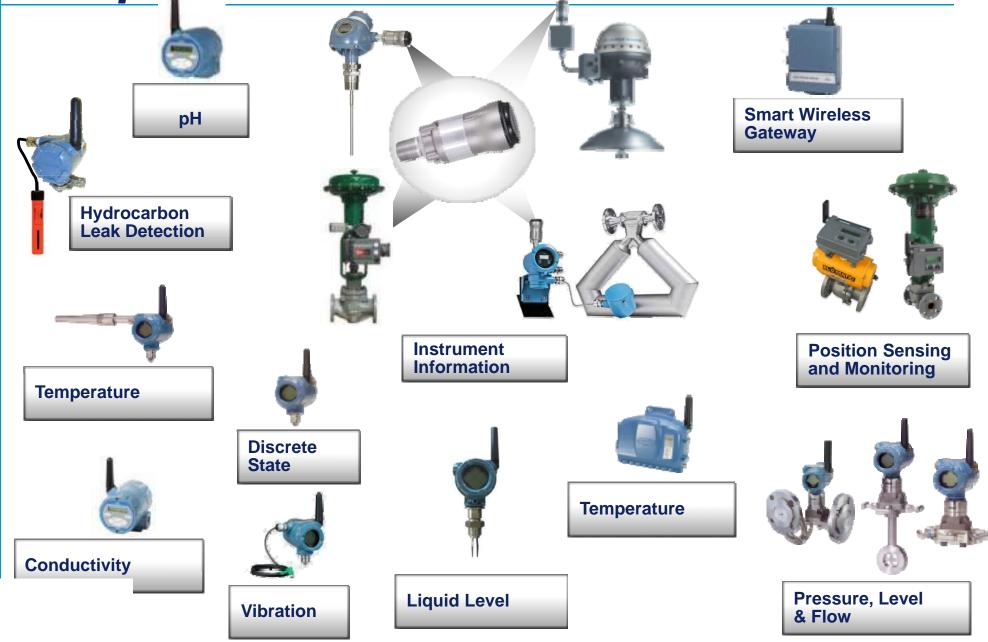
- Business drivers
  - Reduced cost
  - Get process insight of remote areas
  - Comply environmental regulations
  - Improve safety

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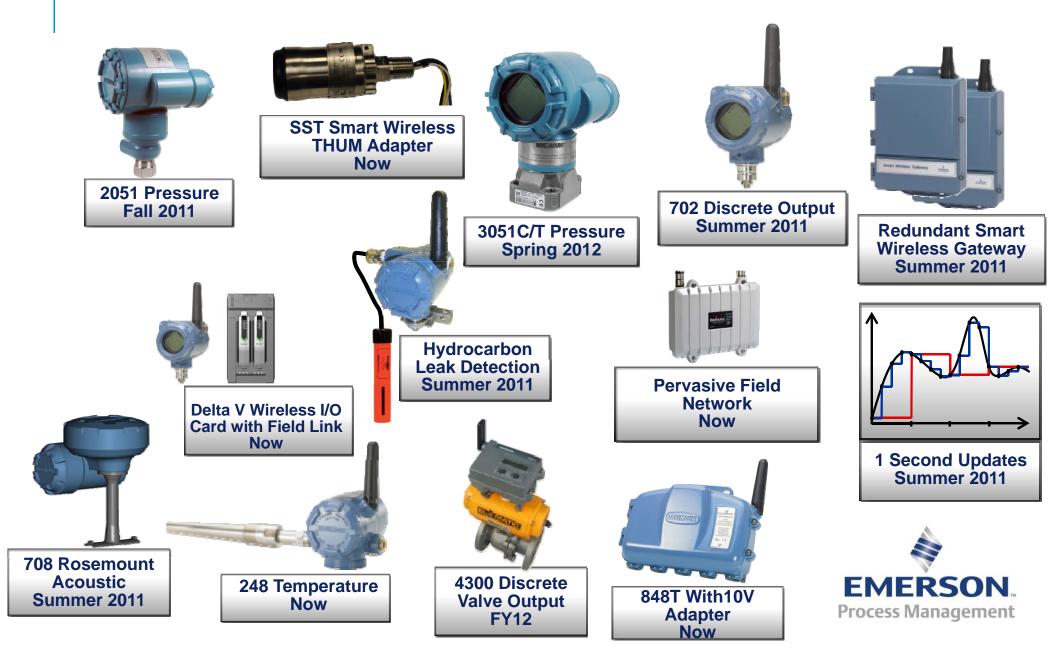
Smart Wireless Offering of Products is Comprehensive …

pH

Hydrocarbon Leak Detection

Temperature

Conductivity

Discrete State

Vibration

Instrument Information

Liquid Level

Temperature

Smart Wireless Gateway

Position Sensing and Monitoring

Pressure, Level & Flow

More Innovative Products Coming Soon!

2051 Pressure Fall 2011

SST Smart Wireless THUM Adapter Now

3051C/T Pressure Spring 2012

702 Discrete Output Summer 2011

Redundant Smart Wireless Gateway Summer 2011

Delta V Wireless I/O Card with Field Link Now

Hydrocarbon Leak Detection Summer 2011

Pervasive Field Network Now

1 Second Updates Summer 2011

708 Rosemount Acoustic Summer 2011

248 Temperature Now

4300 Discrete Valve Output FY12

848T With10V Adapter Now

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Rosemount 3051S Wireless Pressure Transmitter

WirelessHART
Expanding the Possibilities

- Proven 3051S Scalable SuperModule® Platform
  - Integrated Pressure, DP Level, and DP Flow Solutions (3051SFx)
  - Ultra and Ultra for Flow Performance
  - 10 Year **Stability**, 12 Year Warranty!
- Rich HART Data & Diagnostics
  - 4 User Configurable Alerts
- Large Local Display
- Available with SST and Aluminum housings
- SmartPower™ Power Module
  - 10 year life
  - Intrinsically Safe

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I.S. Class 1 Div 1 Approvals

Rosemount 648 Wireless Temperature Transmitter

- Accept Wide Variety of Sensor Types
  - Thermocouple, RTD, mV, Ohm
  - 4 – 20 mA signals
- Rich HART Data & Diagnostics
  - Open or short diagnostics
  - 4 User Configurable Alerts
- Large Local Display
- Available with SST and Aluminum housings
- SmartPower™ Power Module
  - 10 year life
  - Intrinsically Safe
- CPS Offering

I.S. Class 1 Div 1 Approvals

Wireless High Density Temperature
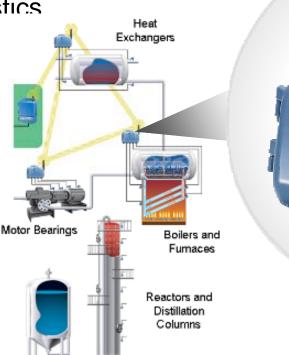
Features:

- Four independently configurable inputs (RTDs, Thermocouples)
- Robust design for harsh environments - NEMA 4X, IP66
- Intrinsically Safe Class 1, Div 2; Zone 0
- Sensor and process diagnostics
- WirelessHART

Applications:

- Distillation columns
- Chemical reactors
- Heat exchangers
- Bearing monitoring
- Storage temperature

Emerson Advantage

- Reduced cost on high density applications
- Insight into equipment health and operational efficiencies

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Process Management
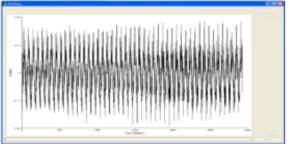
Vibration Monitoring

- **CSI 9420 Wireless Vibration Transmitter**
  - Enables wireless vibration monitoring of any asset
  - Single or dual accelerometers
  - Single accelerometer with temperature
  - **Full waveform or PeakVue thumbnails**
- **Detect typical machine problems**
  - Imbalance, misalignment, looseness
  - Rolling element bearing defects
  - Gear defects
  - Pump cavitations
- **Replace manual inspection rounds**

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Wireless pH Transmitter

Features:

- Compatible with most pH sensors
- Contacting conductivity transmitter to follow
- Supports multiple menu languages
- SMART-enabled
- WirelessHART

Applications:

- Cooling water pH
- Hazardous areas monitoring
- Effluent/ waste water monitoring
- Raw receiving water analysis
- Environmental monitoring

Emerson Advantage

- High accuracy and reliability for monitoring applications
- Connectivity for hard to reach applications

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Process Management

Wireless Vibrating Fork Liquid Level

Features:

- Advanced instrument health / self-checking diagnostics
- Configuration via 375/475 or AMS
- PlantWeb alerts
- Suitable for use in Zone 0 or Class 1 Division
- WirelessHART

Applications:

- Suitable for most liquids
- High and low level alarm
- Overfill protection
- Run dry / pump protection
- Leak detection

Emerson Advantage

- Previously Inaccessible or uneconomic alarms
- Additional Wireless nodes to strengthen network

Wireless Discrete Transmitter
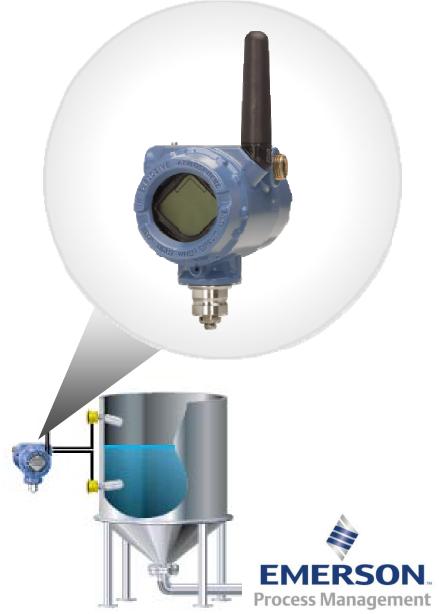
Features

- Works with most non-powered switches
- Single or Dual inputs
- Suitable for use in Zone 0 or Class 1 Division 1
- WirelessHART

Applications

- Incremental monitoring
- Level monitoring
- Safety showers and eye wash stations

Emerson Advantage

- Reduce operator rounds in hazardous areas
- Increase monitoring options in hard to reach locations

Rosemount 702 Discrete Transmitter Enhanced Capabilities

Features:

- Two channels each configurable to input or output
- Input
  - 10 ms pulse detection
  - State and Count reported for each channel
- Output
  - 100mA max current
  - 24 VDC max voltage
- IEC approved *Wireless*HART
- 10 year battery life
  at 32 second updates

Applications:
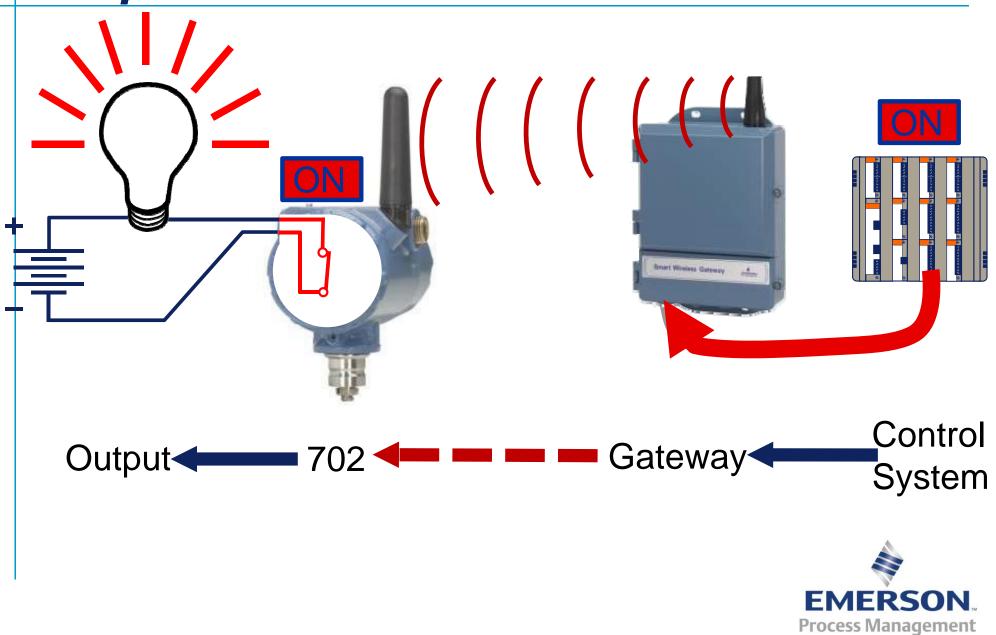
- Plunger arrival detection
- Gas valve shut-in
- Motor Control
- Pump Control
- Lights and Alarms

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Rosemount 702 Wireless Discrete Output

Output ← 702 ← Gateway ← Control System

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Smart Wireless Liquid Hydrocarbon Leak Detection
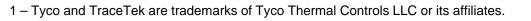
- Wireless Liquid Hydrocarbon Leak Detection
  - Rosemount's 702 Transmitter integrated with:
  - Tyco® TraceTek® Fast Fuel Sensor[1]
  - Tyco® TraceTek® Sensor Cable

- Emerson's Smart Wireless and Tyco's TraceTek technologies combine to provide leak detection where not possible before

- IEC 62591 (*Wireless*HART) ensures network reliability & compatibility

ROSEMOUNT®

TraceTek

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Process Management

1 – Tyco and TraceTek are trademarks of Tyco Thermal Controls LLC or its affiliates.

In Production and Available Now

- Hydrocarbon Leak Detection
  - New option code 61 on the 702 Wireless Discrete Transmitter.
  - Tyco Fast Fuel Sensor or TraceTek Sensor cable.
  - When liquid hydrocarbon touches the sensor, or sensor cable, the circuit is completed, making a discrete input to the 702.

702

Fast Fuel Sensor

702

TraceTek Sensor Cable

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Emerson WirelessHart

- Augments existing or planned PLD systems

- Able to economically bring process data from remote locations

- Easy engineering with built-in power budget

- Decrease uncertainty

- Decrease detection time

- Monitor previously unmonitored, high risk environments

www.EmersonSmartWireless.com

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APPENDIX O

CONFERENCE EVALUATION FORMS SUMMARY

ADEC 2011 Pipeline Leak Detection Conference SurveyMonkey

Please indicate your satisfaction rating pertaining to the following statements.

	Excellent	Good	Fair	Poor	N/A	Response Count
Session 1: PLD Users Group Panel Discussion	**42.9% (15)**	40.0% (14)	8.6% (3)	0.0% (0)	8.6% (3)	35
Session 2: Meter-Based PLD Solutions and Related Practices	40.0% (14)	**48.6% (17)**	8.6% (3)	0.0% (0)	2.9% (1)	35
Session 3: Vapor Detection and Liquid Sensing PLD and Related Practices	**72.2% (26)**	19.4% (7)	5.6% (2)	0.0% (0)	2.8% (1)	36
Session 4: Fiber Optic PLD Technology and Related Practices	**71.9% (23)**	25.0% (8)	0.0% (0)	0.0% (0)	3.1% (1)	32
Session 5: PLD Meter Technology and Related Practices	**41.9% (13)**	**41.9% (13)**	12.9% (4)	0.0% (0)	3.2% (1)	31
Contribution of the exhibitors to the conference	38.2% (13)	**41.2% (14)**	11.8% (4)	0.0% (0)	8.8% (3)	34
Time alloted to visit the exhibits	31.4% (11)	**48.6% (17)**	8.6% (3)	2.9% (1)	8.6% (3)	35
Variety of topics presented at the conference	32.4% (11)	**52.9% (18)**	11.8% (4)	0.0% (0)	2.9% (1)	34
Evening exhibitor reception and networking event	20.6% (7)	26.5% (9)	11.8% (4)	2.9% (1)	**38.2% (13)**	34
Courtesy and responsiveness of on-site conference staff	**51.4% (18)**	40.0% (14)	2.9% (1)	0.0% (0)	5.7% (2)	35
Overall conference satisfaction	**48.5% (16)**	**48.5% (16)**	0.0% (0)	3.0% (1)	0.0% (0)	33
For sharing information and ideas, the conference proved to be	42.9% (15)	**54.3% (19)**	0.0% (0)	0.0% (0)	2.9% (1)	35
					answered question	36
					skipped question	0

For future conferences, I would like to suggest that the following topics be included:	
	Response Count
	18
answered question	18
skipped question	18

Q2. For future conferences, I would like to suggest that the following topics be included:	
1	Leak PREVENTION.	Sep 29, 2011 5:01 PM
2	User presentations or user/supplier presentations What works, what doesn't, etc. Above not to exclude manufactueres presentation	Sep 29, 2011 4:56 PM
3	Topics for a different conference: Pipeline testing protocol and methods; protection systems for pipelines and tank systems; pipeline integrity and corrosion control.	Sep 29, 2011 4:54 PM
4	Any topic that can improve public confidence in pipelines.	Sep 29, 2011 4:52 PM
5	How these systems meet regulations and what regulations are met/not met.	Sep 29, 2011 4:50 PM
6	How to package a system that requires multiple vendors, and problems matching them up.	Sep 29, 2011 4:48 PM
7	Include above ground tank leak detection technology or similar.	Sep 29, 2011 4:46 PM
8	Specific examples of projects that combine the complementary leak detection technologies as successful pipeline mgmt systems. Customized systems for: above ground pipelines, large diameter pipeline systems. ALL technologies for natural gas and vapor product pipelines for Arctic environments. These are for future gas development.	Sep 29, 2011 4:45 PM
9	The question and answer format was excellent. Great idea to limit questions to topic and LD.	Sep 29, 2011 4:30 PM
10	Recommend expanding to other operating assets (tanks) that need leak detection. Include a session that summarizes State and Federal regulatory requirements for leak detection.	Sep 29, 2011 4:25 PM
11	Response related: Effective Recovery Rate Calculation for Mechanical Equipment Response and prevention for offshore facilities	Sep 29, 2011 4:16 PM
12	All presenters should have some slides to show Detection of oil under ice and	Sep 29, 2011 4:05 PM

Q2. For future conferences, I would like to suggest that the following topics be included:

snow

13	Oilfield operations both upstream and downstream	Sep 29, 2011 4:03 PM
14	Speaker position to the screen is too close and difficult for speaker to see. It is better to use the wireless mic like Section 5. Stage should be larger.	Sep 29, 2011 3:57 PM
15	Handouts include papers or presentations; notes pages in handout book; (maybe no volunteers), but want to see a represented installation by company -- to explain selection, installation, operation	Sep 29, 2011 3:56 PM
16	Regulatory requirement -- State of Alaska, DOT, etc. (brief summary)	Sep 29, 2011 3:53 PM
17	Have ADEC Reps discuss their adoption of new technology for compliance options. Have AOGC Reps discuss synergy with ADEC & operators to make AK O&G production profitable again.	Sep 29, 2011 3:51 PM
18	Economic and financial advantages; Government regulations such as leak quantities required for reporting; and pentalties and enforcement	Sep 29, 2011 3:42 PM

Additional Comments:

	Response Count
	27
answered question	27
skipped question	9

Q3. Additional Comments:

1	I thought the conference was well put together and well done. There is no question that your running of the conference and control of the crowd was masterful! How many conferences would turn out so much better if only there was that level of knowledgeable and capable leadership. Well done. For the most part the speakers and presentations were quite good. A number of the speakers were more monotone than might be wanted, but even those gave good presentations. An address/contact list would be most useful the next time, or even after the fact this time. I would offer that guidance to presenters might include having presentations that are bright and readable from the back of the room. The layout was good, the audio/visual was also well done and Randy did a great job of getting and keeping things going when the crowd was a bit slow on the uptake. And the selection and mix of presenters and vendors was just right to cover the territory.	Sep 30, 2011 3:14 PM
2	Really like the ad design for the conference. The conference was well managed and organized. The way the exhibit and the sessions were laid out worked well. The topics covered were great as well. I recommend using a spiral bound for the handout with extra note pages. The comb bound were catching the pages making it difficult to turn pages easily.	Sep 29, 2011 5:03 PM
3	At the lunch break the PPT Slide said to go to the Summit! Lunch was on the 2nd Floor! Ice water in the exhibit area would have been nice. Could have used round tables for this size attendance; MUCH more comfortable for everyone. Put presenters names in the program! Put presenters names on a PowerPoint slide! Moderator needs to use more careful enunciation/diction. Get a sponsor for the networking reception so you can serve beer/wine. Need more tables/chairs at lunch.	Sep 29, 2011 5:01 PM
4	PLD Expert Randall Allen offered his opinion TOO much. He should have initiated more questions.	Sep 29, 2011 4:57 PM
5	Would like to see more test results.	Sep 29, 2011 4:56 PM
6	Great job! Well organized and professional!	Sep 29, 2011 4:54 PM

Q3. Additional Comments:		
7	Thanks for putting this on!	Sep 29, 2011 4:52 PM
8	Very good coverage of various topics. Thank you for organizing.	Sep 29, 2011 4:51 PM
9	The questions on the cards was a good idea for time management, but I think open questions would have been more productive.	Sep 29, 2011 4:49 PM
10	Better chairs. Info, package was great.	Sep 29, 2011 4:48 PM
11	Room setup - trash cans only one between the two rooms.	Sep 29, 2011 4:46 PM
12	Session 1: Real life Alaska! We would like to hear more from current Alaska operators. We would like to hear more from vendors with Alaska or similar experience in Arctic regions: Effectiveness; logistics; installation; maintenance; costs; regulatory requirements; lessons learned. The Q&A sessions were efficient. The collection of written questions was very organized and all listener's got benefit from the discussions. If most leaks that have caused problems recently on the North Slope are connected with releases from small leaks, weeps and seep, it can be inferred that: 1) AK requirements of detection of leaks of greater than 1% flow/day have been successfully met, or appear to have been met. 2) If the other spills that go undetected are only found by personnel from visual or factory observations, it appears that the operators need to improve weep and seep leak detection, and implement low volume leak detection. 3) Regulations should be updated to require defined volumes that are not acceptable for release, as defined by: *actual volumes, or *by maximums for different sensitive areas, or *by maximums for High Consequence Areas, or *a combination of all these. Specifics for violations must be made more defined, and performance expectations better clarified throughout Alaska, and enforced equally for all operators.	Sep 29, 2011 4:45 PM
13	Need more time for exhibits.	Sep 29, 2011 4:29 PM
14	Only a single "user group" member participated throughout the conference. The others were useless and there is no reason they should be here without contributing practical information and experience.	Sep 29, 2011 4:27 PM
15	Do not start so early (0700am). The refreshments were plentiful and much appreciated. :)	Sep 29, 2011 4:25 PM
16	First Session during the morning should be shorter than 2 hours; no more than 1.5 hours with break to use the restroom. Otherwise, the 2 hours time frame is good.	Sep 29, 2011 4:23 PM
17	Excellent moderation and timekeeping.	Sep 29, 2011 4:21 PM
18	State of Alaska should try to avoid using locations with labor issues. I'm glad there wasn't a picket line! However, the chairs, conference room, etc. were very good! Lunches were far too expensive.	Sep 29, 2011 4:16 PM
19	I thought the questions via card submittal was excellent because I believe more candid questions were asked because of the confidential nature. These questions were outstanding! The technology experts questions of the presenters was excellent!	Sep 29, 2011 4:14 PM
20	Further excellent aspects include: all logistics (sound, presenter's tables, screen), refreshments & break area, facilitation (Julie) and staying on schedule,	Sep 29, 2011 4:12 PM

Q3. Additional Comments:

expert evaluator (Randall). Session 2 was slightly more difficult for me to follow (some/most presenters were very technical). Regardless, I learned many new things in Session 2 and in the other sessions. I appreciate that exhibitors were here -- they add to the spirit and are largely also presenters - but I didn't take time to visit booths. I did talk to presenters. Session 5 was generally too hard for me to follow, although I gleaned tidbits (both presentations), and really both are very important.

21	The questions on cards idea was good. If these questions are technical in nature, the facilitator should screen out questions regarding COST which is NOT technical and doesn't belong in the technical Q&A. Please more breaks!	Sep 29, 2011 4:05 PM
22	Pleased with the repetitive information between vendors. This helped commit this to memory. I also didn't gain a lot more information from the questions asked by Randall. He had great questions, but the attendees questions are more important, right?	Sep 29, 2011 4:03 PM
23	Good job!	Sep 29, 2011 3:59 PM
24	More feedback from ADEC - what are they liking, what are they not liking Walk up questions immediately following all presentations More time on the user presentations/panels	Sep 29, 2011 3:56 PM
25	Consider combining with Instrument Society (ISA) conference held every 2 years; need better advertising and publicity.	Sep 29, 2011 3:53 PM
26	I gave a fair to variety of topics only because no presentation from ADEC and/or AOGC on AK's future regarding leak detection. New techonology is hamstring if the regulatory agencies are not accepting new systems for L.D.	Sep 29, 2011 3:51 PM
27	I recommend that ADEC sponsor this meeting annually	Sep 29, 2011 3:42 PM