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"Clear Knowledge in the Over Information Age"

Preventing Pipeline Releases

Prepared for the
Washington City and County Pipeline Safety Consortium

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This document is based on an evaluation of NTSB liquid pipeline failure reports PAR-0201 (Chalk Point, MD) and PAR-0202 (Bellingham, WA), and the gas transmission pipeline failure report PAR-03/01 (Carlsbad, NM). All observations and comments are derived from information supplied in these documents as well as data clearly in the public domain.

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Executive Summary

This white paper report presents a brief synopsis of the series of major breakdowns or events that became linked resulting in the liquid pipeline rupture in Bellingham, Washington, liquid pipeline leak in Chalk Point, Maryland, and the natural gas transmission pipeline rupture near Carlsbad, NM presented in the various NTSB[1] reports for these events. Observations then focus specifically on the eight probable cause findings identified in the NTSB reports and processes critical to avoiding similar failures. This work builds from a previous paper developed for the State of Washington Joint Legislative Audit and Review Committee ("JLARC")[2] and now incorporates a review of the NTSB pipeline accident investigation for Carlsbad not available when the report to JLARC was originally issued.

The title of this report has been changed to distinguish this updated version from the original. Specific recommendations that should be undertaken to address system failures observed in these three pipeline events are summarized on page 29. These recommendations apply to both liquid and gas pipelines and are listed in priority of effectiveness, with most effective listed first. The recommendations have been modified slightly from the original report to JLARC not only to capture the Carlsbad failure, but also to address a wider audience that now includes industry, government (federal, state, and local), and the public. The report to JLARC was directed specifically to the Washington Utilities and Transportation Commission ("WUTC") Pipeline Safety Division.[3] We wish to thank JLARC for their permission to utilize portions of the original report in this paper.

Pipeline inspection approaches as dictated by the federal Office of Pipeline Safety ("OPS"), including the newly enacted High Consequence Areas ("HCAs") and pipeline Integrity Management ("IM") programs, do not address the root cause system failures that resulted in the Bellingham and Chalk Point tragedies and the serious historical inspection shortcomings the NTSB identified in the Carlsbad tragedy. Inspection efforts that concentrate on "over-detailed" documentation and checklist approaches to insure compliance with specific sections of federal regulations can easily miss major management system failures.[4] A "micro detail" or component approach generates volumes of paperwork, but misses the larger pipeline system perspective critical to

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[1] NTSB is the National Transportation Safety Board, a federal agency chartered by Congress with independently investigating various major transportation system failures including pipeline accidents involving death or substantial property damage.
[2] Richard B. Kuprewicz "Preventing Pipeline Failures," report to JLARC, December 30, 2002.
[3] The WUTC is responsible for intrastate pipeline safety and acts as an agent for the Office of Pipeline Safety on all interstate pipelines within the State of Washington.
[4] Both the Olympic Pipeline and El Paso Pipeline had undergone OPS inspections several months prior to the Bellingham, WA and Carlsbad, NM failures. Neither of these inspections uncovered the serious root cause breakdowns that contributed to these tragic failures.

preventing pipeline failures. A recently released Government Accounting Office ("GAO") report also indicates that the new emphasis on pipeline IM will be extremely manpower intensive and that the OPS, even with additional staffing, must still rely on support from State Pipeline safety programs.[5] A different and more efficient inspection approach that focuses limited manpower on system understanding and compliance is thus warranted.

Very seldom are pipeline failures caused by random events or by one breakdown. This report's brief synopses of the Bellingham, Chalk Point, and Carlsbad failures clearly demonstrate this point. Extensive experience and analysis indicate that most pipeline failures result from a combination of major process or management system breakdowns that individually would not necessarily cause failure. As these breakdowns are permitted to continue, however, initiator events eventually occur linking these system breakdowns to produce major releases, sometimes with very tragic and expensive consequences.

Another inspection approach is especially important as the industry shifts to greater reliance on risk-based or "performance" management principles that can be harder to quantify and inspect. Principles to quantify performance management have yet to be properly defined, tested, and codified. We continue to encourage development of new technologies and techniques that advance the reliability of anomaly[6] determination to prevent pipeline releases. The recently release GAO report indicates major expert consensus in OPS's increased efforts to improve technologies that can enhance pipeline safety.[7] Given the still developing state of certain inline inspection tools and direct assessment IM technologies and processes, however, a prudent pipeline company will elect to operate their system within intended design parameters.

[5] GAO Report GAO-02-785, "Pipeline Safety and Security – Improved Workforce Planning and Communication Needed," page 28, August 2002.
[6] An anomaly is any imperfection in pipeline wall or weld.
[7] GAO Report GAO-03-746, "Pipeline Safety – Systematic Process Needed to Evaluate Outcomes of Research and Development Program," findings page, June 2003.

Olympic Product Pipeline Rupture in Bellingham, Washington, June 10, 1999 - a brief synopsis

Late on the afternoon of June 10, 1999, a 16-inch liquid products pipeline operated by Olympic Pipeline Company ("OPL") ruptured in the City of Bellingham, Washington. The 16-inch pipeline was part of an approximately 400-mile pipeline system running through western Washington (from Cherry Point, Washington to Portland, Oregon) that had been installed in the 1960's.

Shortly before 3:00 p.m. on June 10, 1999, a "computer system administrator" entered a software program change into the SCADA[8] computers responsible for monitoring and controlling the pipeline. The programming was intended to be a minor change that would create new historical records of data on pump vibration for future analysis. Not only was the change made while the computer system was online, but the administrator unknowingly entered a "typo" that minutes later caused a slowdown in the computer's scanning rate, substantially affecting the ability to monitor and control the pipeline. Some minutes later a control center operator, responsible for monitoring and controlling the pipeline operation from a centralized control room, and unaware of the impact of the software programming, began a routine pipeline delivery switch at the Renton pump station (MP 112.9).[9] This step served as one of the initiators linking a chain of events that eventually resulted in the pipeline rupture almost 100 miles upstream. Switching the Renton delivery points caused a routine operating backpressure wave at Renton that began moving back upstream in the 16-inch pipeline. Such waves travel at the speed of sound in the fluid, which for a product pipeline are approximately three-quarters of a mile per second. It is important to note that the control room operator at the time would not be expected to understand the problems in the SCADA system nor its impact on his ability to monitor and control the pipeline.

As the control room operator noticed the backpressure wave moving up the pipeline, he discovered that the SCADA system was not responding to his repeated computer command attempts to start a pump at Woodinville Pump Station (MP 86.8), the next pump station immediately upstream of Renton. Pump startup was a common operating practice to stop such a wave from moving up the 16-inch pipeline. The backpressure wave quickly moved past the Woodinville Station, through the Allen Station (MP 41.4), and into the new Bayview Terminal Station (MP 39.1). Bayview Terminal had been a source of operating difficulties since its startup in mid-December 1998. Between December 16, 1998, when the Bayview Terminal went into operation, and June 10, 1999, the main inlet block valve at Bayview closed 41 times with pressures exceeding 1,000 psig on the upstream pipeline on 13 of these occasions. A mis-operating relief valve within Bayview Terminal played a major role in these upsets.

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[8] SCADA stands for Supervisory Control and Data Acquisition.

[9] For the purposes of this report, all milepost ("MP") references are approximate with the Ferndale pump station immediately upstream of Bellingham set as milepost zero.

As a result of a series of extensive process, quality control, design, operating, maintenance, startup, and management errors, omissions, or failures in the Bayview Terminal installation and integration into the pipeline system, the normal operating backpressure wave initially generated at Renton (some 70+ miles downstream) caused the Bayview Terminal to go into an automatic shutdown. Among other things, this automatic shutdown generated a high-pressure surge wave in the pipeline immediately upstream of the facility.[10] This high-pressure surge wave rapidly moved further up the pipeline toward the next pump station at Ferndale. When this surge pressure wave reached a major weakness in the pipeline at MP 16.2 in Bellingham, it caused a pipeline rupture failure at approximately 3:28 p.m. Shortly after rupture, the Cherry Point Pump Station (approximately 5 miles upstream from Ferndale, MP -5) and the Ferndale Pump Station (MP 0) pumps upstream from the rupture "tripped off" (went into automatic shutdown with alarms to control room). The only remaining operating pump on the 16-inch system (at Woodinville) was subsequently shut down by a control center operator at 3:31 p.m. Remote operated block valves on the pipeline, however, were not closed.

The computer program errors were not immediately recognized as the source of the computer problems. Because the SCADA computers were "mirrored," both the main and backup SCADA computers became contaminated by the program error. As a result, both computers were taken through a series of startups and shutdowns that essentially left the control room operators "blinded" to real time pipeline events and suspicious of questionable alarms and data that occurred prior to, during, and following the rupture, as the SCADA computers were taken on and off line. Four major impacts from the computer problems were: 1) a substantial increase in computer scan time of the pipeline system from 3 seconds to over 3 minutes (resulting in slow or non-response monitoring and/or control center commands), 2) data gathered on the online computer was not necessarily passed to the other computer that was shut down, creating information gaps as they were switched, 3) for a period of approximately 10 minutes immediately after the rupture both computers were down, and 4) the leak detection system was "neutered" as it required approximately 15 minutes of baseline data following a SCADA restart. The programming typographical error entry was eventually discovered, corrected, and both computers fully restored at approximately 4:04 p.m.

With the return of both computers to "normal" operation, the pipeline pumps were restarted at 4:16 p.m. Following the restart of the pipeline, a SCADA computer leak alert alarm was received at 4:29 p.m. At 4:31 p.m. the control center operator started a second pump at Ferndale. Shortly thereafter, the pumps at Cherry Point and the Ferndale stations again went into an automatic shutdown. An OPL employee in the area of Whatcom Creek in Bellingham reported his observation of a possible gasoline leak to the control center. The control center operator initiated a full pipeline shutdown that, this time, included closure of the remote operated block valves on the

[10] For the purposes of this report, a high-pressure surge wave is defined as a surge pressure wave in excess of maximum operating pressure or "MOP" for liquid pipelines and maximum allowable operating pressure, or "MAOP" for gas pipelines.

pipeline. The pipeline remote block valves were finally closed approximately 1 hour and 5 minutes after the pipeline rupture. At 5:02 p.m., 1 hour and 34 minutes after the rupture, Bellingham Fire Department personnel responding to various earlier 911 calls about gasoline odors and fumes, witnessed an explosion and fire in Whatcom Creek.

The resulting explosion and fire cost the lives of three young men in the park at the time. In addition, extensive damage occurred to the City's water treatment plant and approximately 1.5 miles of sensitive parkland was engulfed in a fireball as the liquid/vapor cloud moved downhill toward more populated areas of the city before ignition.

The NTSB investigation of the failed pipe after the accident, determined that the pipe rupture initiated at an external gouge in the pipeline that had been created by construction activity five years previously.[11] This specific external gouge generated no dent in the pipe, but was approximately 8 1/2 inches long, 20% into the pipewall, and oriented almost longitudinally (with the flow) along the axis of the pipe. Detailed metal analysis indicated that failure resulted from overstress in one event or a high pressure "burst" rather than from pressure cycling induced flaw growth.[12] There was extensive evidence of other damage to the pipe such as dents and additional gouges in various orientations in close proximity to the failure site (the NTSB reported 33 dents/gouges in the approximate 20 feet of pipe analyzed from the rupture site). Prior smart pig inspections had suggested changes in the pipe and identified various anomalies in the general area of the failure. Through a series of errors, omissions, and mistakes after the inline inspections, OPL had chosen not to uncover the pipeline to field verify these possible anomalies in the area where failure eventually occurred.

Observations Related to the Pipeline Failure in Bellingham

NTSB Findings

In their report conclusion, the NTSB identified twelve findings, five probable causes, and two recommendations concerning the Bellingham failure. The probable causes or events are listed below. For ease of reference we have labeled each of these events in parentheses for additional discussion.

1. The pipeline was damaged and weakened by work done near the pipeline by IMCO during the 1994 Dakin-Yew water treatment plant modification project and Olympic Pipeline Company's ("OPL's") inadequate inspection of the contractor's work (Encroachment Management).

[11] The NTSB has determined that one-call had been utilized for the Dakin-Yew water treatment plant construction project, but not for subsequent field construction changes, and that Olympic Pipeline onsite inspection was inadequate for the various activities associated with this major project.

[12] Pressure cycling can cause certain types of anomalies to grow over time to the point that they may eventually fail.

2. OPL's inaccurate evaluation of inline inspection results led the company to not excavate and inspect the damaged section of pipe where failure eventually occurred (Inline Inspection Process).

3. OPL's failure to adequately test all safety devices associated with the Bayview Products Terminal before starting up this facility (Quality Control and Pre-Startup Checklists).

4. OPL's failure to investigate and correct conditions leading to repeated unintended closures of the inlet block valve at the Bayview Terminal (Pipeline System Perspective).

5. OPL's practice of performing software database work on their SCADA computer system while it was operating the pipeline in real time (Pipeline Monitoring).

Observations Pertaining to Bellingham Failure

The NTSB, in presenting their Final Report observations on October 8, 2002, indicated they limited their recommendations to OPS to only 2 items because many of their concerns had been addressed in the recently promulgated series of new federal pipeline regulations. While we concur with most of the NTSB findings and recommendations, we believe that the new federal regulations still fail to adequately address key process elements or approaches needed to efficiently prevent the probable causes identified by NTSB in the Bellingham failure.

Focusing on the five above listed NTSB "probable causes," we recommend critical process elements to avoid the specific breakdowns or failures in the future. These elements are presented in order of greatest impact in preventing the ultimate failure of the pipeline, with the most valuable presented first. There are many significant reasons for this prioritization. Among the major factors are: 1) in an era of deregulation, the economic temptation is high for pipeline transmission systems to crowd or push existing capacity and operating pressures above MOP/MAOP, 2) recent major restructurings within the industry create potential for serious confusion about pipeline design intent, 3) inappropriate risk management decisions fostered by unclear understanding of the pipeline system design abound, and 4) Federal Energy Regulatory Commission ("FERC") judicial rulings support the obligation of transmission pipelines to operate at MOP/MAOP.

1) Pipeline System Perspective

Crucial to any pipeline operation is a clear understanding of the pipeline system's intended design and operation, especially with respect to pressure and maximum velocity (flow) that can affect pressure. Pipelines operating at the higher ranges of velocity in order to maximize capacity can be especially susceptible to generating surge pressures. Despite this fact, federal regulations permit operating pressures in excess of MOP for liquid pipelines, or MAOP for gas pipelines.

a) Baseline Data

An understanding of the clearly documented design parameters set for the system ("Baseline Data") is vital to appreciating the operating limits of a pipeline system. Baseline Data should include: 1) the MOP/MAOP throughout the system, 2) maximum design flow rate, 3) identification of all devices that can cause surge pressure (i.e., pumps and their impeller size, pressure control, as well as check and remote block valves), and 4) all safety devices intended to insure flow and pressures stay within intended limits (location, type, and setpoints). This information is pivotal to understanding the intended dynamics of any pipeline system and is usually portrayed on a simplified block flow diagram of the pipeline. Other information such as elevation and hydraulic profiles can also be utilized to supplement the Baseline Data, but without a basic understanding of the pipeline system's ability to affect pressure, such additional information can be misapplied. While this may seem an obvious prerequisite, there are no regulatory requirements that a pipeline operator have such documentation or even limit their operations to the maximum intended design conditions.

b) Management of Change Procedure

Once Baseline Data information has been approved for a pipeline system, no modifications or changes to the pipeline should be permitted without another critical element, a Management of Change ("MOC") process requiring formal approval of such changes prior to their operation.

MOC should be triggered by any change to pipeline equipment or operation that can affect pressure (or ability to contain pressure). Change means any modification to any equipment other than a replacement in kind. To illustrate this concept, the replacement of an old 11-inch pump impeller with a new 11-inch impeller would not trigger a MOC review. Replacement of an 11-inch impeller with a larger 11.5-inch impeller would trigger a MOC as such a change can impact pipeline flow, pressures, especially surge pressures, as well as the effectiveness of existing safety equipment.

The complexity of a MOC process should depend on the nature and size of the change. MOC can involve a simple signoff by an appropriate engineer for a minor change, or a more complex signoff by a larger technical team for large changes such as new pump or compressor stations. A review by more than one level of technical management (not direct reports) is also required to insure appropriate checks and balances in the MOC process.

MOC documentation should be simple and clear so that a regulatory inspector could easily understand and determine that safety equipment to protect the pipeline system is appropriate for the change and that such equipment was properly reviewed and approved. Changes would not require regulatory approval, but records documenting such changes and the MOC process should be made available during a regulatory inspection. Note, however, that all MOC changes should be reviewed, approved, and updated on the Baseline Data documents by the pipeline operator prior to startup.

Despite these simple requirements, there are currently no MOC requirements mandating a "system review" for any changes on a pipeline, even if those changes may cause operating limits to be exceeded.

c) "Safety Critical" Devices

A prudent operator will determine if safety critical equipment is being operated frequently.[13] By "safety critical" equipment on pipelines we mean those specific devices intended to be the last line or level of defense in preventing overpressure. Examples of such devices are high pressure shutdown switches, control valve interlocks, and pressure relief valves.

Frequent operation and dependence on "last line of defense" safety equipment is a serious sign of problems in the design and operation of the pipeline. Frequent operation of these devices can change the reliability, and setpoint,[14] of these devices so that they do not operate as intended when truly needed. If such devices are operated frequently, they become pressure regulators, not safety devices, which is an entirely different function and purpose. In the Bayview Terminal, the frequent mis-operation of first, the inlet control valve (CV 1904), then the pressure relief valve (RV1919), and finally the main inlet block valve (MV 1903), and the cumulative resulting impact of driving the main pipeline into surge overpressure should have raised serious questions about the Bayview Terminal's installation and integration into the pipeline system.

Current regulations do not require the reporting of "last line of defense" overpressure safety equipment that might indicate abusive pipeline operation.

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[13] 49 C.F.R. §195.406(b) and 49 C.F.R. §192.201 require pipeline operators to prevent pressures from exceeding 110% MOP/MAOP anywhere in their pipeline, but other sections of federal regulations (49 C.F.R. §195.55(b) for liquids and 49 C.F.R. §191.23(b) for gas) permit operators to avoid reporting such mis-operation, a serious flaw in current regulations.

[14] Setpoint is the pressure value that the device is set for by the designer. For various technical reasons the safety device will usually begin operating at a pressure slightly lower than the setting, and pressure will exceed settings by some accumulation value.

2) Quality Control and Pre-Startup Checklists

In the initial startup of any new equipment, two management elements are especially relevant. Quality Control ("QC") and Pre-Startup processes serve as critical checks that equipment intended for safe pipeline operation has been properly ordered, received, installed, calibrated, tested, and that pipeline personnel are properly trained on such equipment prior to its operation. While these specific elements seem obvious, the simple fact is that there is no specific regulatory requirement mandating that a pipeline operator utilize either of these crucial elements to insure the quality of installed equipment meets design intent.

QC

Quality Control requires at least one level of check that the equipment received is the equipment ordered and specified by the design engineer. It is also not uncommon to require more than one level of checks and signoffs for critical safety equipment. Such checks are usually made against a "master" purchasing procurement order that has been approved by engineering management involved in the design of the particular equipment and system review.

Pre-Startup Checklists

Startup of new equipment utilizes punchlists that are checked off to insure that new equipment field installation and calibration coincide with engineering design, and that personnel have been trained and understand the changes and impacts on the pipeline system before startup. Pre-startup documents can be fairly simple for minor additions, or very complex for facilities such as a terminal installation. Included in all check-off lists (usually one of the first items to be checked off) is an indication that a proper MOC review has been completed for the design and installation. Other startup check-off list requirements address such issues as verification of safety equipment set point values, initial calibration/testing, operating and maintenance procedures, and SCADA modifications that must be completed before new equipment is placed into operation.

3) Inline Inspection Process

Since the Bellingham failure, new federal regulations have been promulgated pertaining to pipeline Integrity Management ("IM") for liquid pipelines.[15] Gas pipeline IM is currently undergoing final rulemaking. While IM can play a critical role in insuring that pipelines are sound by setting minimum inspection requirements, IM's influence on pipeline safety can be overstated, especially if a pipeline is mis-operated or abused between inspections. Pipeline IM programs that rely heavily on inline inspection or smart pigs, and that fail to include critical inline inspection elements discussed below, can be

[15] 49 C.F.R. §195.452 "Pipeline Integrity Management in High Consequence Areas," finalized January 2002.

highly ineffective and illusionary. This point is clearly demonstrated by the inadequacies in the inline inspection programs in both the Bellingham and Chalk Point failures.

In addition, over-reliance on IM principles without including critical management process elements presented in this report can seriously increase the risks of pipeline rupture. In layman's terms we describe over-reliance on IM to prevent pipeline rupture as the "Myth of Integrity Management." There are currently no regulatory requirements or industry recommended practices setting minimum inline inspection pig capability performance standards; this is a serious shortcoming. Unfortunately, the recently issued API Standard 1160 for liquid pipeline IM (developed after the Bellingham incident) fails to clearly capture many of the concepts discussed below. This leaves room for misapplication of inline inspection tools especially in identifying third party damage. Omission of any of the critical inline inspection elements discussed below can render an inline inspection program ineffective.

a) Identify Risks of Concern

An effective inline inspection program should first include a clear statement identifying the specific risks that are of concern on a particular pipeline segment. The choice of a particular inline inspection tool should depend on that smart pig's capability to reliably determine these specific identified risks of concern anomalies.[16] Usually more than one pig technology is required as there is normally more than one type of risk of concern on a pipeline. Indications that only one type of pig is utilized in an inline inspection program should raise questions about the effectiveness of both the inline inspection process and the overall IM program.

b) Proper Tool Selection

While inline inspection tools can be highly effective at detecting certain at risk anomalies, these smart pigs are selective in their ability to determine various types of anomalies. No one smart pig is currently capable of determining all anomalies that may result in rupture failure. Most anomalies tend to fall into the following general classes: corrosion metal loss (i.e., general and selective), third party damage related (i.e., gouge, dent, or dent with gouge, abnormal stress/deformation, or cathodic protection interference), pipe manufacturing related (i.e., longitudinal seam weld), construction related (i.e., gouge, dent, or dent with gouge, wrinkles/buckle, or girth weld defect), and deformation from environmental forces (i.e., earth, water or lightning), causing buckling, thinning, or weld zone failure.

[16] An "at risk" anomaly is defined as any deviation from normal pipe or weld that could fail. It should be noted that all pipelines have anomalies. Most of these anomalies are not "at risk."

c) Clear Screening Criteria

Depending on the risks of concern expected to be discovered by the smart pig tool, clear criteria to filter and prioritize the extremely large volume of data produced by such tools is required. Criteria should be in writing to insure understanding of the tool's objectives, to assist all parties (including possible third parties) reviewing the data, to minimize false field digs, and to provide a clear historical record of the pig run analysis. For liquid pipelines, criteria will usually follow at least the minimum repair guidelines required in ASME B31.4 as well as the repair and timing guidelines (immediate, 60-day or within 6 months) defined in federal pipeline regulations affecting high consequence areas ("HCAs"), 49 C.F.R. § 452(h)(4).[17]

d) Team Review of Critical Data

One of the greatest potential areas for mistakes while utilizing inline inspection lies with mis-interpretation of pig data by either the vendor or the pipeline company. Given the vast volume of information that must be processed and the importance that a proper inline inspection can play in the safe operation of a pipeline, prudence would dictate that such critical reviews not rely on just one individual. To minimize the risk of error from misreads, multiple reviews by different individuals or teams, trained and experienced in such skills, should be mandatory. These independent reviews should then be compared against each other and differences reconciled. Key differences that cannot be reconciled should be identified as candidates for high priority field digs for proper verification.

e) Field Digs and Calibration Curves

Once a smart pig or pigs have been run, a sufficient number of field verification digs should be required as part of the inspection program. Data from field digs should then be used to develop a "confidence plot or calibration curve" (pig anomaly calls graphed against field measurements) that substantiates the pig vendor's anomaly detection claims. However, there are no recommended practices or regulatory requirements calling for development of confidence plots in inline inspections.

f) Integrated IM Program

All specific pig run information must be integrated into an overall "centralized" integrity management database that is subject to independent review by a pipeline management team and regulatory personnel. This process assists the management team in verifying that risks of concern have been properly identified and appropriate inspection approaches selected for their pipeline system. In this specific area, we believe federal

[17] Gas pipelines follow repair criteria outlined in ASME B31.8, and gas transmission HCA rulemaking addressing repair timing is in the final stages of development.

liquid pipeline regulation 49 C.F.R. § 195.452(g), which requires all information to be integrated into an overall IM analysis is beneficial.

4) Pipeline Monitoring

There currently are no federal pipeline regulations requiring the use of computers, such as SCADA, to real-time monitor and operate pipelines. However, if a liquid pipeline has computational pipeline monitoring (CPM) leak detection, the pipeline operator must comply with minimum requirements and other practices defined in API 1130.[18] The new liquid pipeline HCA regulation, 49 C.F.R. § 195.452(i)(3), also requires that "an operator must have a means to detect leaks on its pipeline system." This wording does not mandate CPM leak detection and allows the use of non-real time leak detection (i.e. aerial flyover). None of these regulations or practices addresses the computer system issues that caused the SCADA failure in the Bellingham incident.

The NTSB, in their recommendations pertaining to the Bellingham failure, noted the critical breakdowns associated with the SCADA system and advised the Office of Pipeline Safety to issue an advisory bulletin to all operators using SCADA computers in their pipeline operations. The NTSB counseled operators to perform SCADA programming modifications on separate offline systems.

Independency vs. Redundancy

We commend the NTSB for their critical observation relating to the SCADA breakdown that served as one initiator to the Bellingham tragedy. We suggest further expansion on one crucial process element regarding SCADA computers, and for that matter any safety critical equipment. It is normal industry practice for SCADA computers to be placed in pairs, one main operating unit with a second unit standing by as a backup unit. This duality, or redundancy, provides a high level of reliability provided that the two computers are designed and operated truly independently. The NTSB reported that the two OPL computers could mirror each other. The links to permit mirroring of information provided redundancy without true independency, substantially reducing the reliability of this system. The dual computers essentially operated as one computer. Programming errors entered into the main computer were rapidly transferred to the backup system, negatively affecting both computers. For safety critical equipment, redundancy does not truly provide increased reliability if such systems can be easily linked to the same failure (in the SCADA case, mirroring). It is a prudent industry practice for safety critical devices to incorporate at least two levels of independent protection to prevent catastrophic failure (this does not mean two pieces of identical equipment).

[18] 49 C.F.R. §§ 195.134 and 195.444.

5) Encroachment Management

Federal legislation (49 C.F.R. § 195.442 for liquid pipelines and 49 C.F.R. § 192.614 for gas pipelines) sets minimum requirements for damage prevention programs including written procedures to prevent damage to the pipeline from various excavation activities. While these federal regulations focus largely on public education and one-call systems they must incorporate additional processes to be effective. In the Bellingham case, both the pipeline operator and excavating contractor were aware of each other. Yet, because of other breakdowns not addressed by one-call, extensive damage still occurred to the pipeline contributing to its ultimate failure. Additional damage prevention regulatory efforts should balance one-call and public education with the following concepts directed toward pipeline operators:

a) ROW Encroachment Tracking System

Within the pipeline company, a centralized tracking system (ideally computer based) must be established that traces, documents and monitors all pipeline right-of-way ("ROW") encroachments. Such a system should capture not only one-call notifications, but also any ROW encroachment observations reported by pipeline personnel. Pipeline personnel are usually more sensitive at spotting activity on the ROW that may not be reported into one-call. As input can come from many sources, the need for a central concise database is obvious. This database will include as-built documents supplied from responsible parties once work is completed and all pipeline onsite inspection logs, such as that developed for at-risk construction activities.

b) Focus on Managing the ROW

For various reasons the exact location of a pipeline (depth and position within the ROW) may change with time. A prudent pipeline operator will not rely on maps, pipeline signs, global positioning data, or markers to determine the exact location of the pipeline when evaluating a high-risk encroachment threat. Such techniques should only be utilized to identify the location of the pipeline ROW. The pipeline operator's responsibility is to insure that the pipeline is within the ROW.

Because the pipeline can be anywhere within the ROW, an operator should treat any activity within the ROW as a potential third party damage threat until further evaluation proves otherwise. The company should focus on managing the activities within the ROW and incorporate a review process that identifies which potential ROW encroachments require field verification and determination of the exact location of the pipeline before work is permitted. In the more severe threat cases, onsite field inspection and monitoring may also be required while the work is underway and appropriate logs completed accordingly.

c) Dynamic ROW Monitoring

Sufficient manpower resources within a pipeline company must be allocated to permit proper monitoring of various unique encroachment threats. Operation of heavy equipment near the pipeline ROW for a major project installation demands a very specific higher level of field inspection and monitoring than brush clearing on or near the ROW. A prudent pipeline company will continuously monitor such high "at risk" threats and insure appropriate, trained manpower is available to monitor such unique activities.

d) Encroachment Approval

Final decisions related to critical "at risk" encroachments should require approval by appropriate levels of a management team. Management level approval will depend on various factors, such as risk in high consequence areas, potential to damage the pipeline, and proximity of other pipelines or structures. This approval process will recognize that one does not have to hit a pipeline to damage it. In order to assure proper checks and balances, no one individual should be solely responsible for decisions on critical ROW encroachments.

e) Assertive Protection of ROW

Federal pipeline regulations (49 C.F.R. §§ 192.614 and 195.442) place the ultimate responsibility for damage prevention programs on pipeline operators. Crucial to a successful and effective program is the philosophy of the management team supporting protection of the ROW. Because of the greater consequences of a release, a pipeline company operating in HCAs should have a more assertive philosophy in support of proper ROW management processes. The management team not only should recognize but also assure adequate resources are provided in this critical area to insure its success.

f) Control Center Notification

Daily communication of the status of all active, critical pipeline ROW encroachments to the control center operators (usually via a database that these operators can quickly review) is crucial to safe pipeline management. The control center personnel are the personnel actually controlling the pipeline. They should be kept informed of all operations that may place the pipeline at risk. Information that needs to be passed on to the control center includes the location, type of encroachment (equipment), company representatives, if any, who may be onsite, whether operating pressure of line needs to be lowered, and finally, notification when work for the day is completed.

Piney Point Pipeline Failure at Chalk Point, Maryland, April 7, 2000 - a brief synopsis

The Piney Point Oil Pipeline is a simple pipeline system approximately 51.5 miles long, consisting of 16-inch and 12-inch pipe segments, constructed in 1971-72 and placed in operation in 1973. The Chalk Point to Ryceville pipeline segment involved in this accident consists entirely of 12-inch pipe and is approximately 11 miles in length. The system essentially receives fuel oil from marine vessels at Piney Point and deliveries oil to a power plant at either Chalk Point or Morgantown. The Ryceville Transfer Station located downstream of the Piney Point Facility functions as a switching and flushing oil station for the separate pipeline segments serving the Chalk Point or the Morgantown power plants.

At 7:15 a.m. on April 7, 2000, a pump was started at the Chalk Point Station launching a cleaning pig and diesel fuel into the pipeline segment between Chalk Point and the Ryceville Transfer Station. This movement was intended to displace No. 6 Fuel Oil[19] already in the pipeline in preparation for running a smart pig inline inspection tool. Pipeline control center monitoring of this simple pipeline system usually occurred at the pipeline's Piney Point Station, the main terminal receiving facility for the entire system.

Oil movement for this specific transfer was to be monitored by means of manual balancing. Manual balancing consisted of taking periodic hand tank gauges at the Chalk Point and Ryceville tanks, converting the gauge reading to barrels and then comparing the barrel changes on the tanks at each end of the pipeline during the movement for any major imbalance. For some reason the Piney Point pipeline controller who would normally be responsible for balancing and monitoring movements on the pipeline was bypassed. Instead, the Ryceville gauger was given the task of converting tank gauge readings from Chalk Point and Ryceville into barrels and balancing this specific pipeline transfer. The Ryceville gauger failed to do such balancing in a timely manner throughout the oil movement. This mis-operation set a series of events in place that permitted a simple leak to cascade into a serious release.

When the cleaning pig failed to arrive at Ryceville at the expected estimated time, approximately 1:00 p.m., various checks were made to insure that a valve had not been left open that could have otherwise diverted flow. For a variety of reasons the delivery pump into the pipeline at Chalk Point was not shut down until 3:38 p.m.[20] A balance eventually calculated by the Piney Point pipeline controller determined a 3,088 barrel discrepancy in the movement. A subsequently ordered aerial inspection

[19] No. 6 Fuel Oil is a thick black oil product that becomes solid at ambient temperatures and must be hot to flow. After a Fuel Oil movement, diesel fuel is utilized to displace the black oil from the pipeline before it can cool and solidify.

[20] The NTSB's investigation later determined that pump shutdown occurred some 10+ hours after the pipeline failure.

discovered a major spill in the pipeline right-of-way on power plant property, at approximately 6:00 p.m.

Through a serious of errors, mistakes, omissions, and misinformation, the pipeline spill was initially reported to the National Response Center (NRC) at 8:50 p.m. as a 2,000 gallon spill[21] and mis-classified by the NRC as a fixed plant failure (spill was on power plant property but was a pipeline leak). As a result, not all appropriate federal agencies, including the Office of Pipeline Safety, State, or local emergency responder agencies, were notified of a large release in a timely manner. Because of these errors, especially the low spill volume initially reported, appropriate resources were not quickly brought to bear on the spill. Contributing to the eventual spread of this large release was an initial project management style of response rather than an Incident Command System ("ICS") response that has proven more effective on pipeline spills. The project management approach in the first critical hours of the response proved ineffective at containing the spill in a limited area as weather conditions deteriorated later that evening, allowing the oil spill to migrate. Eventually spill response was shifted to an ICS approach that proved successful in limiting the rapidly spreading oil contamination to approximately 41 miles of sensitive coastline, resulting in cleanup costs of $71 million.

Post accident investigation revealed that the pipeline had failed at an outside wrinkle bend[22] or buckle that generated a circumferential crack hole 6 1/2 inches long by 3/8 inches wide at its widest point. Ironically, this wrinkle had been mistakenly identified as a "T piece" anomaly by the pig vendor on a previous 1997 ultrasonic pig inspection.[23] [24] Also known at the time was that the Piney Point Oil Pipeline had a history of wrinkle field bends as a result of its initial construction and that the line operated in "cycled" heated service. Further investigation revealed that the crack had in all probability failed when the pipeline pressure was at its highest point as delivery began at about 7:15 a.m. on April 7, 2000.

Observations Related to the Pipeline Failure at Chalk Point

NTSB Findings

In their conclusion, the NTSB identified five findings, two probable causes, and three

[21] The NTSB investigation has indicated that at the time the operator initially reported the spill volume, other more accurate information showed that the line balance was actually 3,000 barrels short and that the spill covered 3 to 4 acres in the wetlands at Swanson Creek.
[22] A wrinkle bend is a bend in the pipe that contains one or more buckles. Wrinkle bends usually occur during the original installation of the pipeline.
[23] Previous geometry and magnetic flux leakage in-line inspection "smart pig" tools had been run in 1995. The magnetic flux leakage tool did not correlate well with field dig measurements.
[24] In August 1997 both a caliper pig and an ultrasonic pig were run in the pipe segment that eventually failed. The ultrasonic pig analysis produced the erroneous evaluation.

specific recommendations pertaining to the failure at Chalk Point. The two probable causes or events identified by the NTSB are listed below. For ease of reference we have labeled each of these events in parentheses for additional discussion:

1. Cause of the leak was a fracture in a buckle in the pipe that was undiscovered because data from an inline inspection tool was interpreted inaccurately (Inline Inspection Process).

2. Operating procedures and practices for monitoring the flow of fuel in the pipeline to insure timely detection were inadequate, contributing to the magnitude of the spill (Pipeline Monitoring).

Observations Pertaining to Chalk Point Failure

In the Chalk Point failure, the probable causes reported by the NTSB are related to several key elements discussed in detail in the previous Bellingham failure section. Additional comments, however, are warranted as this independent event further emphasizes the importance of these previously discussed elements in effectively preventing pipeline failure.

1) Inline Inspection Process

The 11-mile segment of the Piney Point Oil Pipeline had undergone numerous inline inspections, even though federal regulations did not mandate smart pigging. The pipeline had been previously inspected by: 1) a geometric pig, 2) a magnetic flux pig, 3) a caliper pig, 4) and an ultrasonic pig. Apparently, none of these smart pigs identified the wrinkle bend anomaly that caused the leak.

It should be noted that the NTSB report goes on to indicate that wrinkle bends were a known issue on this pipeline and are permitted as grandfathered anomalies not now allowed in new pipeline construction or installations. Although many older pipelines operate under design conditions grandfathered in under federal pipeline regulations, there are currently no specific federal requirements that a pipeline operator take into special consideration those grandfathered risks not now permitted in new pipeline operation.[25] We recommend that pipeline operators clearly identify those grandfathered risks no longer permitted in new pipeline installations, but that are present on their specific pipelines. We wish to note that grandfathering does not absolve the pipeline operator from the consequences of a pipeline failure.

a) Identify Risks of Concern

The pipeline operator chose to initiate a fairly aggressive smart pig program utilizing several different pig technologies and employed field

[25] It could be argued that new HCA regulations will now capture grandfathered issues, but such issues could extend as long as seven years for liquid pipelines and ten plus years under proposed gas transmission HCA regulations.

digs to develop calibration curves of those pig runs. Based on the poor performance demonstrated by the developed calibration curves, the operator even rejected magnetic flux pig technology in favor of ultrasonic pigs for this particular pipeline segment. Use of a particular smart pig tool or technology is dependent upon the particular anomaly "risk of concern" attempting to be identified and the pig vendor's ability to determine those "at-risks" anomalies that can fail.

In identifying the risk of concern, the operator failed to recognize wrinkle bends as a potential failure risk in this particular pipeline. The operator missed two critical issues: 1) wrinkle bends were a known construction defect in this particular pipeline, and 2) the pipeline was heavily thermal-cycled as a result of moving hot and cold product in the pipeline (a serious failure exposure on wrinkled pipe). Such indicators should have placed wrinkle bends on a "risks of concern" list for thermal cycle stress failure. Failure to clearly identify winkle bends as a major risk of concern may have resulted in utilization of the wrong inline tool to catch such anomalies. In this case caliper pig technology may have proven much more effective (and cheaper) than ultrasonic pigs at identifying wrinkles. Though it is worth noting that apparently neither the geometric nor the caliper pig identified the buckle that eventually failed.

Given the NTSB recommendation regarding wrinkle bends, it is apparent that the various pig capabilities were misstated. As mentioned previously, the limitations and capabilities of the specific pig tools must be understood if inline inspection is to be relied upon in any IM program.

b) Team Review of Critical Data

The error made by the vendor in mistakenly characterizing the failure site as a "T anomaly" underscores another aspect of inline inspection, also previously mentioned in the Bellingham failure section. Given the possible consequences of a pig reading miscall, critical analysis needs to be performed by more than one individual with each review performed independently and results then compared and differences properly reconciled. Personnel performing such critical reviews must be trained and experienced in such analysis. If differences cannot be reconciled, they must be placed on a high priority list for field dig verification.

2) Pipeline Monitoring

While the NTSB report fails to mention the specific form of remote (SCADA) pipeline system monitoring, if any, it is very clear that any remote monitoring of the Chalk Point pipeline segment was ineffective: metering was bypassed during pigging operations. Furthermore, a manual balancing process utilizing tank gauges did not involve the pipeline controller located at the Piney Point Station who was chartered and specifically trained in the responsibility of "monitoring" the pipeline system via balancing, even simple manual balancing. It is worth noting that the pipeline controller eventually performed the appropriate balance that correctly identified a 3000 barrel leak in the pipeline segment.

Leak Detection

As previously mentioned, the new HCA regulation does not specifically define leak detection and permits the hand balancing approach that significantly contributed to this specific spill. We recommend regulatory changes that further define leak detection requirements for HCAs. The definition should provide for "real time" remote monitoring to assist in more timely determination, with the ultimate selection of a particular leak detection technology at least focused on rupture detection. In many cases more than one leak detection technology may be warranted to capture the three types of pipeline releases: seepage, fixed orifice, and rupture.

Natural Gas Transmission Pipeline Rupture and Fire near Carlsbad, NM, August 19, 2000 - a brief synopsis

On August 19, 2000, line 1103, a 30-inch diameter El Paso Natural Gas (EPNG) gas transmission pipeline operating at approximately 675 psig, ruptured near Carlsbad, NM. This rupture took place in the proximity of two other operating gas transmission pipelines, a 26-inch diameter line 1100 and a 30-inch diameter line 1110.[26] The rupture occurred approximately one mile upstream (east) of the Pecos River Compressor Station. This station received natural gas from the above three transmission lines moving gas from the east, plus a fourth pipeline supplying gas from Northern New Mexico, 16-inch line 3191, to supply gas to markets further west.

At approximately 5:26 a.m. the control room operator ("controller") monitoring the pipeline via SCADA at the gas control center located in El Paso, Texas, received a rate-of-change alarm[27] for one of the three gas turbine compressors at the unattended Pecos River Compressor Station. Less than a minute later a second compressor shut down and the station went into automatic emergency shutdown, isolating the compressor station from the gas transmission pipelines.[28] Several seconds later additional alarms were received at the control center including a rate-of-change alarm for falling inlet pressure at the Pecos River Compressor Station. The controller would not necessarily have known which pipeline was causing the falling inlet pressure alarm. In response to the alarms, the controller requested accelerated updated information from SCADA on the compressor station instead of the usual automatic scan data that occurred automatically at 4-minute intervals. At about this time the transmission of data from the Pecos River Compressor Station to the SCADA computer was briefly interrupted.

At approximately 5:30 a.m. the controller telephoned the Pecos River district station lead operations specialist at his home and asked him to send people to the Pecos River Compressor Station. The specialist then called out two personnel to report to the Pecos River Station. At about this time a local EPNG employee (pipeline operations specialist) located at his home south of Carlsbad noticed a glow in the southern sky and suspected an EPNG pipeline might be involved. He called the gas control center and asked if any pressure changes had been noticed and passed along

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[26] A fourth EPNG pipeline, 16-inch No. 1000, was also nearby but was out of service under inert nitrogen pressure.

[27] A rate-of-change alarm is triggered when selected monitored parameters change beyond established set conditions (i.e. suction pressure changes by so many psig per minute).

[28] It is not unusual to design compressor stations to automatically isolate from main gas transmission pipelines in certain emergencies. Such design usually calls for shutdown of the compressor(s), automatic closure of valves isolating the station from the pipeline(s), opening of blowdown valves to an atmospheric vent to depressure gas lines within the station, cutoff of main electrical power, and limited operation of certain systems (i.e. lube oil, communication) on backup power to monitor and protect critical equipment.

his observations. He then called his operating supervisor (pipeline lead operations specialist) and proceeded to report to the Pecos River Compressor Station.

At 5:31 a.m., the gas control center again experienced an interruption of data to the SCADA system from the Pecos River Compressor Station that prevented the controller from receiving any additional information from this station. The station was equipped with an uninterruptible power supply to maintain backup power to critical equipment, but the local computer and modem link to SCADA apparently were not connected to this backup power system. SCADA communication with the Pecos River Compressor Station was not reestablished until 9:04 a.m.

At 5:31 a.m. the local 911 emergency telephone operator received numerous calls from residents reporting a fire and the sound of an explosion. An off-duty EPNG employee who lived near the site also called 911 and reported a fire.

At 5:35 a.m. a controller again called the station lead operations specialist at home and indicated that he suspected a possible pipeline failure. At this time the controller did not know which pipeline was involved. The specialist indicated that he could now see indications of a fire in the early morning sky in the direction of the Pecos River Compressor Station and that he was on his way to the station.

At 5:44 a.m. a controller called the attended Keystone Compressor Station (57 miles upstream of rupture) feeding gas into lines 1103 and 1110 and asked for compressors to be shut down. The controller then called the attended Eunice Compressor Station (53 miles upstream of rupture) feeding line 1100 and requested similar compressor shutdowns. At 5:50 a.m. the controller called the attended South Carlsbad Compressor Station (25 miles upstream of rupture) feeding line 3191 to confirm compressor shutdown. It should be noted that even with the compressors shut down, the compressed gas inventoried in the miles of pipeline from the various compressor stations would continue to de-pressure out the ruptured pipeline for some time.

At 5:45 a.m. the pipeline lead operations specialist was the first to arrive at the Pecos River Compressor Station near the accident site. This employee began closing transmission pipeline block valves downstream of the rupture, near the Pecos River Compressor Station, approximately 1 mile west of the fire. A block valve on line 1100 was closed first. A second pipeline operations specialist arrived and proceeded to assist in closing block valves on lines 1103 and 1110. The downstream pig launcher valves that could permit gas to flow back up the pipeline towards the rupture were then closed.

At approximately 6:10 a.m. the station lead operations specialist arrived at the Pecos River Compressor Station and met the two pipeline operations specialists in the process of closing valves. The station specialist verified that the station had properly shut down and then assisted the pipeline specialists in closing the block valve from the North line 3191. This line not only fed into the station but also fed lines 1103 and 1110 via various cross connections.

After closing the block valves downstream of the rupture, the two pipeline operations specialists proceeded to drive to the west side of the Pecos River service bridge to view the fire across the river, but could not determine which pipeline had ruptured because of the size and intensity of the flame. The fire was estimated to be approximately 500 feet in height based on nearby suspension bridge tower support structures. The two men then drove across a low-water crossing in the river north of the rupture as heat radiation prevented their using the pipeline service bridge across the river near the rupture site. Because of the heat intensity as well as limited right-of-way road access, emergency responders were instructed by EPNG to stage and remain west of the Pecos River Compressor Station until EPNG personnel could bring the release situation under control.

At about 6:05 a.m. the two operators, carefully checking that they could tolerate the heat, left their vehicles and proceeded to close block valves on the east side of the river, approximately one quarter mile upstream of the rupture site. A block valve was first closed on line 1100 with no noticeable change in the fire's intensity. Next, block valves on lines 1103 and 1110 were closed with a noticeable reduction in fire intensity. The bypass valve on the line 1103 pig receiver was then closed and the fire subsided after several minutes. At approximately 6:21 a.m., 55 minutes after the initial rupture, operation personnel at the valves notified the gas control center that all appropriate valves where closed and that the fire was out.

At the time of the rupture, 12 members of an extended family were camping at the Pecos River on the east bank near the pipeline service bridge that provided EPNG vehicle right-of-way access and carried two of the gas pipelines. Six members of the family were discovered at a campsite approximately 675 feet from the rupture. The remaining six members were found further west of the campsite (away from the fire) as they had apparently jumped into the river in an attempt to escape the heat. All twelve family members eventually died from injuries sustained from the fire.

The NTSB investigation determined that the gas decompression force from the pipeline rupture of line 1103 generated a 51-foot-wide crater approximately 113 feet long, adjacent to the pipeline. A 49-foot section of the ruptured 30-inch 1103 pipeline was ejected from the crater in three pieces with the largest section of the ejected pipe found about 287 feet northwest of the crater. The ejected pipeline pieces exhibited evidence of internal corrosion damage. Extensive burn damage was observed to have occurred on both sides of the river. Cable stays for two pipe suspension bridges spanning the river were hit and damaged by pipe shrapnel causing the two pipelines they carried to settle onto the riverbanks (neither pipeline failed, however). The suspension bridges and their accompanying pipeline sections have since been removed.

Detailed metallurgical analysis of the failed pipe identified severe internal corrosion along the interior bottom of the pipeline with no evidence of external corrosion. There was also no evidence of internal corrosion on the top interior of the pipe. The area of corrosion damage extended 21 feet 5 inches along the pipe with the most severely corroded area reducing the original pipe wall thickness by 72 percent.

Corrosion was focused at a low point created opposite wrinkle bends generated at the top of the pipe when the pipeline was originally installed.[29] Corrosive material could accumulate at this low point to form a corrosion cell. While not the cause of the failure, there was also evidence of selective internal corrosion at girth and longitudinal seam welds along the bottom of the pipe. Further analysis of the fracture site disclosed that the pipe fracture resulted from an overstress separation with no evidence of fatigue cracking or corrosion degradation. At the failure site, pipeline operating pressure was 675 psig or 80 percent of MAOP.[30] In other words, the pipe wall thinned from internal corrosion to the point that the remaining pipe wall failed as a rupture at the operating pressure.

A liquid removal "drip" system, located upstream of the rupture site and intended to prevent liquids from entering a section of the pipeline that could not be pigged, was found to be partially clogged allowing some liquids to continue downstream and collect at the rupture site. While segments of the various pipelines were able to run cleaning pigs,[31] the pipeline segments immediately upstream of the Pecos River Compressor Station, including the rupture site, were incapable of running such tools. Following this rupture, this section of pipeline has been modified to permit running of pigs.

On performing an Office of Pipeline Safety ordered pipeline segment hydrotest prior to restart, a section of pipeline approximately 2,100 feet downstream from the rupture site also failed. This hydrotest failure was also attributed to internal corrosion with a general wall thickness reduction of 69 percent. Before the accident, the segment of line 1103 between the Keystone and Pecos River Compressor Stations had never been internally inspected nor hydrotested (except for two minor segments).[32]

Observations Related to the Pipeline Failure near Carlsbad, NM

NTSB Findings

In their report conclusions, the NTSB identified one probable cause, nine major findings, and four recommendations concerning the gas pipeline rupture near Carlsbad. The NTSB determined that the probable cause of the failure and subsequent fire was a significant reduction in pipe wall thickness due to severe

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[29] While wrinkle bends are no longer allowed in newer pipeline installations, these anomalies are permitted or "grandfathered" for older pipelines.
[30] MAOP is Maximum Allowable Operating Pressure.
[31] A cleaning pig is a smaller flexible device, usually a plastic or rubber sphere or plug, that is run inside a pipeline. Cleaning pigs are more flexible and more capable of traveling through various tighter-bend pipelines than the longer, heavier smart pigs that incorporate electronic sensors and computers.
[32] Many pipelines operating before the passage of federal pipeline regulations are grandfathered from testing conditions required of newer pipelines. The Pipeline Safety Improvement Act of 2002 now requires all transmission pipelines to undergo a base inspection within a specified time interval from the Act's passage.

internal corrosion. In the probable cause paragraph, the NTSB proceeded to make two important statements, presented below. Related major process elements in parentheses have been added as a reference for further discussion.

1. The severe corrosion had occurred because El Paso Natural Gas Company's corrosion control program failed to prevent, detect, or control internal corrosion within the company's pipeline (Pipeline System Perspective & QC).

2. Contributing to the accident were ineffective federal preaccident inspections of El Paso Natural Gas Company that did not identify deficiencies in the company's internal corrosion control program (Pipeline Monitoring).

Observations Pertaining to the Carlsbad Failure

Two key NTSB observed shortcomings point to serious root cause problems regarding pipeline internal corrosion programs: 1) "federal pipeline safety regulations do not include specific design, construction, operating, or maintenance requirements that address the relationship of water and corrosive contaminants to internal corrosion in gas pipelines."[33] 2) "Current federal pipeline safety regulations do not provide adequate guidance to pipeline operators or enforcement personnel in mitigating pipeline internal corrosion."[34] As a result, federal regulations and current industry standards regarding internal corrosion programs are seriously deficient.

New pipeline regulations codifying more specific guidelines pertaining to internal corrosion programs, especially for gas transmission pipelines, are warranted. These new regulations must capture, among other items, the important concept that material transported in pipelines does not have to be "corrosive" to cause internal corrosion in pipelines that can result in pipeline failure. For various reasons, selective chemical or biological factors can significantly accelerate internal corrosion rates well beyond historically "conservative" observed levels. Very minimal requirements defined in ASME B31.8 and the recently released ASME B31.8S[35] also fail to provide sufficient detailed guidance toward defining effective internal corrosion programs. A more detailed recommended practice that served the industry well for several decades, NACE RP0175-75,[36] was allowed to expire in its last review cycle in 1995 and has since been withdrawn from the official and current industry standard status.[37] Given the increased risk factor trends presented below, internal corrosion risks on gas transmission pipelines should receive special attention.

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[33] NTSB Report, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico - NTSB/PAR-03/01," adopted February 11, 2003, page 27.
[34] Ibid, NTSB Carlsbad Report PAR-03/01, page 46.
[35] ASME B31.8-1999, "Gas Transmission Distribution Pipeline Systems," issued November 16, 2001, and ASME B31.8S-2001, "Managing System Integrity of Gas Pipelines," issued July 19, 2002.
[36] National Association of Corrosion Engineers (NACE) Recommended Practices, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."
[37] Ibid, NTSB Carlsbad Report PAR 03/01, page 35.

There are many reasons to focus additional attention on internal corrosion potential in both liquid and gas pipelines, but several recent trends mandate that wise gas transmission pipeline operation focus heightened and renewed attention on this risk. Identifying just several major recent trends in the gas transmission industry: 1) the move to "free market" natural gas as a commodity can tempt producers to ship product into a pipeline that doesn't meet specification (e.g. exceeding gas treatment equipment design limits during periods of high commodity price spikes); 2) significant consolidation of gas producer, gas transmission pipeline operator, and electric power plant operator under major corporate conglomerates, placing at risk the traditional role of the pipeline operator to enforce quality requirements intended to protect pipelines; 3) unprecedented increases in gas producer and customer gas injection and take-off points on gas transmission pipelines that can dramatically change the originally intended pipeline flow, pressure, and temperature regimes; 4) recent orders by FERC eroding the traditional role of a transmission pipeline operator to enforce technical standards intended to protect transmission pipelines; and 5) misapplication of risk management principles and techniques (i.e. failing to consider "linkage" factors that can substantially increase risk of internal corrosion rupture failure).

It must be stressed that a proper system wide internal corrosion program should be the first line of defense in avoiding pipeline rupture from this specific risk. A prudent program not only will address the general corrosion that resulted in this failure, but also address selective corrosion (e.g. weld heat affected zones) that can cause rupture failures. Several process elements merit additional comments given their role in the Carlsbad failure. These elements are presented in order of their effectiveness to have prevented this failure with the most effective presented first.

1) **Pipeline System Perspective**

   Internal corrosion tends to be a process risk largely related to the material moved in the pipeline, while external corrosion is mainly an environmental risk driven by the soil conditions surrounding a pipeline. Pipeline equipment (pipe coatings and cathodic protection) intended to protect against external corrosion has no effect on preventing internal corrosion in pipelines.

   a) **Baseline Data - System Focus on Internal Corrosion Monitoring and Control**

      Crucial to understanding the risks associated with internal corrosion on a particular pipeline is a clear understanding of the basic pipeline system design and installation and its potential to develop "traps" such as low points or slow flow or "dead/no-flow" zones that can serve as collector points for corrosion reactants (i.e. water) or microbiological activity (MIC).[38] Such areas can become hot zones for selective and high rate internal corrosion resulting in a pipeline rupture as illustrated in Carlsbad.

[38] This author places little technical value on corrosion programs relying on minimum sweep velocity concepts to avoid internal corrosion.

These identified potential trouble sites warrant a higher level of monitoring and inspection than the rest of the pipeline. Pipeline segments that can't be periodically pigged should be inspected more carefully and frequently. A review of current alignment sheets containing elevation profiles and more detailed equipment specific drawings representing uniquely installed equipment (such as the liquid drip leg involved in this event) helps to identify many, but not all, trap areas.

Because of the inability to identify all pipeline low points (i.e. sag bends), a transmission pipeline operator will also periodically run a cleaning pig through their pipeline to sweep out potential corrosion precursors that may be forming in the pipeline. Analysis of the material removed from the pipeline by a cleaning pig will help ascertain the type(s) of internal corrosion that may be occurring. For transmission pipeline segments that cannot be pigged, an operator will incorporate a much higher level of system internal corrosion monitoring than the base set by a proper cleaning pig program. The NTSB reported that sections of the multi-pipeline systems in the Carlsbad area could not be pigged and thus were not cleaned via cleaning pigs. In addition, none of these major pipeline segments had undergone prior hydrotesting or internal smart pig inspection.[39]

Corrosion coupons or probes referenced in current federal regulations[40] can be ineffective at identifying many types of corrosion activity on transmission pipelines that can result in rupture failure. We highly recommend that internal corrosion programs not overly rely on such devices to identify at-risk corrosion. Internal corrosion programs must exceed current federal and industry standards to be effective at preventing pipeline failure from this risk.

b) Management of Change Procedure

Inherent in the Baseline Data requirements discussed in the Bellingham failure under maximum design flow rates, is the premise that the design intent (maximum flow, velocity, pressure, temperature, and quality) of all injection and take-off points be clearly defined, documented, and understood. This is especially important for gas production facilities that feed into gas transmission pipelines. These facilities can fail to meet proper minimum gas quality requirements significantly increasing internal corrosion potential on gas transmission pipelines (i.e. exceeding rated gas treatment plant design flow capacity or exhibiting signs of poor plant operation or maintenance activities that can cause periodic "carryover" of corrosion precursors). For example, if a gas producer has provided

[39] The pipelines were placed into operation prior to establishment of federal pipeline safety regulations and were thus grandfathered from certain testing requirements.
[40] 49 C.F.R. §192.477 "Internal Corrosion Control: Monitoring."

documentation certifying that they were designed to treat or ship 100 MMSCF/D[41], but the pipeline is receiving 150 MMSCF/D from the producer, gas quality should be carefully validated. Any changes to design intent or waiver of tariff quality requirements, which could affect pipeline system internal corrosion potential, should undergo a management of change review and approval by appropriate pipeline company management.

2) Quality Control

Quality specifications in pipeline tariffs, while important to insure the fungibility of product to the consumer, are also intended in many cases to protect the transmission pipeline. While failure to properly specify, monitor, or enforce gas quality tariff specifications can seriously increase the likelihood of internal corrosion, it must be emphasized that the primary level of protection against failure from internal corrosion is an effective pipeline system internal corrosion program assisted by proper quality tariff management and enforcement.

Current federal regulations permit the transport of material that can corrode a pipeline provided that the operator has investigated and taken appropriate steps to mitigate/minimize internal corrosion on the pipeline.[42] There are no specific federal pipeline safety regulations requiring a pipeline operator to determine or enforce pipeline minimum quality tariffs as they pertain to preventing internal corrosion. There are other legal requirements, set by FERC and public utility commissions, requiring pipeline operators to enforce tariffs for commercial reasons but internal corrosion is not usually the driving purpose. For example, gas transmission pipelines operating in warmer climates may accept gas with a higher water content than pipelines operating in colder climates subject to freezing temperatures. Higher water content brings with it a higher potential for selective settlement of corrosion reactants and a greater risk potential of failure from internal corrosion. Meeting gas quality requirements does not guarantee that internal corrosion is not a risk factor for pipeline failure. Quality control actions monitoring and enforcing gas quality entering a pipeline must be in sync with the pipeline system internal corrosion program.

3) Pipeline Monitoring

The NTSB's statement pertaining to pre-accident inspections should be setting off many alarms. As demonstrated by the Bellingham and Carlsbad failures, past federal checklist inspection processes are seriously deficient. In both of these cases, many OPS inspections, even those several months prior to the

[41] MMSCF/D stands for million standard cubic feet per day, an industry standard correcting actual gas flow measurement in cubic feet to standard conditions of 60 °F and 14.7 psia.
[42] For gas pipelines, 49 C.F.R. §192.475(a) and for liquid pipelines 49 C.F.R. §195.519

ruptures, failed to uncover the serious root cause system breakdowns that eventually resulted in these terrible failures. On a more positive note, the lengthy and appropriate OPS Corrective Action Orders for each of these tragedies, as well as the major shift toward developing more appropriate pipeline regulations over the past two years, suggest a change is occurring in the Office of Pipeline Safety. Offsetting this effort, however, is an industry shift away from the historically detailed prescriptive inspections toward a more risk or performance based inspection process. Performance based inspections are harder to quantify and audit, and thus require a new, more effective pipeline inspection approach that has yet to be codified or tested.

We support and applaud continued efforts to improve the efficiency and effectiveness of pipeline regulations and inspection programs. Specific recommendations for improvements garnered from lessons learned from these three failures are summarized on page 29. These recommendations are presented in order with highest priority listed first.

Lastly, further comment on recent federal regulation regarding integrity management for liquid and gas transmission pipelines is warranted.[43] A prudent pipeline operator will not rely primarily or solely on IM to prevent pipeline failures. Given the state of developing inline inspection technology and direct assessment processes for identifying certain at risk anomalies that can cause rupture failure, it is an unwise operator that counts on IM to prevent such events. A pipeline operator will incorporate the process elements presented in this paper in their management approach to designing, operating and maintaining a pipeline. Inclusion of these elements not only improves safety, they are also more cost effective than misapplication of integrity management. IM cannot compensate for poor management approaches or practices regarding siting, design, construction, operation, or maintenance of pipelines. IM is only one tool in a management toolbox that can help serve as a safety net to avoid and prevent pipeline failures.

[43] Federal regulation for liquid pipelines 49 C.F.R. §195.452, "Pipeline Integrity Management in High Consequence Areas," finalized in January 2002, and for gas transmission pipelines, "49 C.F.R. § 192 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines): Proposed Rule." Washington, DC, issued for comment January 28, 2003 and undergoing extensive modifications.

Specific Recommendations for Improvements in Pipeline Design, Operation and Maintenance

Based on the observations provided in this report, the following recommendations should be instituted to insure that pipelines are designed, maintained, and operated safely. These recommendations are presented in priority to be effective and efficient, with the most critical listed first:

1) **Pipeline Inspections**
Inspection should immediately redirect efforts toward verifying that a pipeline's Baseline Data system design is understood and documented on a "simplified flow" drawing, including all tie-in points. Regulatory inspection efforts should then focus on insuring that equipment is properly purchased, installed, operated, and maintained to keep the pipeline operating within this specific design intent. Priority should be given to gas and liquid transmission pipeline segments spanning HCAs, operating at the upper end of their velocity ranges that are at the greatest risk of exceeding MOP/MAOP.

2) **Internal Corrosion Federal Regulations and Industry Standards**
Regulations and industry standards for internal corrosion programs need to be quickly improved. Given the major "factor" trends identified in this report, explicit internal corrosion efforts pertaining to gas transmission pipeline systems should receive priority.

3) **Over-reliance on Pipeline Integrity Management**
In any pipeline safety program there is great temptation to believe IM can play the major role in preventing pipeline failures. IM should not supplant other regulatory efforts that insure pipelines are prudently designed, operated, and maintained. Efforts should be focused on insuring that inspection resources are not overly diverted to IM activities at the expense of specifically recommended items included in this list.

4) **Management of Change**
Regulations should be formulated requiring appropriate Management of Change approval procedures within a pipeline company for any pipeline change of Baseline design that is not a replacement in kind, including product quality specifications entering the pipeline.

5) **Overpressure Reporting**
Regulations should adopt changes that require all pressures in excess of 110% MOP/MAOP anywhere within a pipeline to be reported in a timely manner so that proper mitigation can be assured to prevent reoccurrence.

6) **Safety Critical Equipment**
Pipeline regulations need to provide clearer guidance on safety critical equipment and incorporate the concept of independency for such equipment. This effort

should capture the point that redundancy is not independency. In addition, the frequency of operation of safety critical overpressure equipment should be reported at least annually.

7) **SCADA Computer Monitoring**
Regulations should be adopted requiring SCADA computer "leak detection" monitoring on transmission pipelines operating across HCAs.

8) **Grandfathered Anomalies**
Pipeline companies should compile a list, by pipeline, of all anomalies of concern that are grandfathered, but that would no longer be permitted in new pipeline operation. This grandfathered anomaly list should be disclosed under community right-to-know.

9) **Pipeline Inspection Technologies**
Regulatory efforts should foster further development and proper use of inline inspection tools ("smart pigs") including improvement of industry practices capturing the inspection concepts outlined in this report. Such development must also acknowledge the limited capabilities of these devices even as they continue to improve. Other technologies that may selectively identify certain "at risk" anomalies should also be cultivated.

10) **Third Party Damage Prevention**
Efforts should incorporate additional third party damage prevention processes exceeding the basic current one-call and public education efforts. Emphasis should focus on additional requirements within pipeline companies capturing the concepts defined in this report.

11) **Specialized Expertise**
Given the rapid development and changes in unique pipeline technologies such as smart pigging, hydraulic analysis, corrosion, and leak detection, regulatory agencies should budget sufficient resources to permit the use of independent specialized expertise when needed.

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