PHMSA Contracted Leak Detection Study – DTPH56-11-D-000001, as prepared by Kiefner & Associates, Inc. (KAI)

Document Overview - Comments:

1. The KAI report did not provide a general "lessons learned" summary of the leak incidents. There would have been increased report value if the common deficiencies of LDS personnel, procedures and technologies had been addressed.
2. The report indicates that some LDS technology for liquids pipelines could be applied to gas pipelines. This does not seem to be consistent with the known limitations of CPM for compressible fluids.
3. KAI identifies limitations to flow/pressure LDS that seem to indicate that they cannot function near pump stations. This is not consistent with operator experience with fluid withdrawal tests.
4. The report briefly mentions other regulatory approaches (e.g. TRFL) but a more extensive review could have provided enhanced value.

Section 2 Summary - Comments:

Page 2-6:

The authors interviewed an extremely small number of operators to gain insights into the experiences of the operational community. "Task 4 also reports on interviews held with nine liquids pipeline companies – including two smaller crude oil and petroleum products pipelines; five gas transmission pipelines; and five gas distribution pipelines."

The interview process followed by the authors is deficient in that:

- an extremely small sample size was used, and
- a very informal methodology was used; for example, operators were not asked to fill out questionnaires indicating their practices, just informal telephone surveys.

As a result, the report cannot accurately reflect industry practices or industry opinion. As evidenced above, only nine liquids pipeline companies were interviewed out of 350 registered operators in the United States; a very small 2.6% sample size.

Page 2-12

"In our opinion the API RP 1155 that describes the principles of how to assess the performance of a leak detection system on a liquids pipeline also applies equally well to gas pipelines."

This publication has been withdrawn from the active documents within API. It has been addended into the latest revision of API 1130 Recommended Practice Revision 2007, and just recently been reauthorized by API. Perhaps reference the API 1130 Appendix, suggest re-publication to API, or delete all references to API 1155 within this report.

Section 3 Task 3: Review and Assessment of Previous Pipeline Incidents - Comments

General Comments on use of Form 7000-1 data:

The KAI data presentation in Task 3 is unnecessarily complicated by not filtering the data at the outset to *separate those low consequence events* that are not required to file full detail (release size of less than 5 barrels, no water pollution, no death or injury or fire or explosion and property damage of no more than $50,000). By retaining these low consequence events in the dataset, it appears that many questions have a poor response rate. In fact, these incidents are never presented with the questions about the presence of CPM systems or SCADA, nor about the leak identifier.

KAI compiles the data for larger-than-average size releases (700 barrels) but then misses the opportunity to drive home the difference in the identifier for the smaller releases versus the larger ones. They show the data, but don't elaborate, or even contrast the result for the different data sets: CPM leak detection/SCADA calculations identify 12% of all releases but 39% of the larger-than-average releases. This is key to reasonable expectations about the role and performance of CPM leak detection/SCADA systems.

Comparing the 1986-2004 record with the 2010-mid-2012 record, KAI does not mention the major reason for the decline in the average spill size: the reporting threshold went from 50 barrels (or 5 b/d of HVL) in the period before 2002 to 5 gallons in the period starting in January 2002. It is not clear why KAI would choose 2004 as the end-date for the earlier period; a logical choice would be 2009, the last year during which the 2002 reporting form was in use, or 2001, the last year during which the reporting criteria was 50 barrels. It is also not clear that average release sizes based on such different reporting criteria provide helpful context.

Page 3-13:

The authors did not meet the objective of task 3. A portion of the task 3 charge is reproduced here:

"Determinations shall be made to conclude whether implementation of further leak detection capabilities would have mitigated effects to the public and surrounding environment. Damage to surrounding environment/public must utilize standard fire science practices. The level of protection needed for adequate mitigation shall be determined."

The authors did review past incidents at a gross, overview level but did not examine whether leak detection systems would have mitigated effects to the public and surrounding environment. It would have taken an in depth analysis of each incident to determine if leak detection systems would have addressed that specific incident, an analysis which the authors failed to undertake.

Page 3-20

In conclusion of the section here, there should be a recommendation on what can be done to foster development of better technologies as to detect ruptures and small leaks from the data by the authors per this data analysis.

Page 3-24

"For hazardous liquid incidents located on the ROW, 197 total releases are divided into 119 from pipe body, 13 from a pipe seam, 17 from valves, 5 from flanges, and 43 leaks from something other than pipe, such as a girth weld, repairs, instrumentation etc. The total release volume reported for the 197 incidents was 4,967,895 gallons. The 197 incident reports came from 60 different operators."

These numbers seem inconsistent to the ones in the previous section. Perhaps a clear way to explain the differences may be needed here.

Page 3-27

In the table "Operating" versus "Functioning" - how can there be more functioning than operating?

"For the 197 incident reports, a SCADA system was in place for 153 (78%) of the incidents. Thirty-two (16%) of the incident reports did not respond to this question. For the 197 incident reports, a CPM system was in place for 87 (44%) of the incidents. Eighty-six (86) of these CPM systems were reported as functional at the time of the incident. A CPM system was not in place at the time of an incident for 78 (40%) of the reports in the database."

The numbers do not match the table.

Page 3-28

"The SCADA was reported as functional in 152 of the 197 reported incidents, which is 99.3% of the incidents where a SCADA was operational at the time of the incident. Forty-three (43) of the incident reports stated that SCADA assisted in the detection of the incident. This is 28% of the incident reports that stated a SCADA was operational at the time of the incident. "

The numbers do not match the table or the sections above.

Pages 3-32 and 3-41:

The authors did not pursue to completion why CPM systems were not more useful in identifying releases from pipelines. Even in the larger releases analysis, the authors failed to understand why CPM was not the initial identifier in discovering the release. Without this fundamental understanding of the shortcoming of leak detection systems, it becomes impossible to state that additional, complementary systems should be used by industry (Page 2-2: "The solution can be combination of technology – utilizing multiple redundant independent LDS,"…).

Page 3-62

Amoco Case Study: First "issue" states that SCADA and CPM alerted the controller to shut down the pipeline, however this seems to contradict the description, which indicates that SCADA and CPM did not detect or confirm the leak.

A summary sub-section at the end of the liquids section detailing common themes, and lessons learned from the 11 reviewed incidents would be helpful.

Section 4 Task 4: Technology Feasibility - Comments

Page 4-1:

The authors did not meet the second charge in task 4: "An analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems. "

The authors did not address the question of establishing standards for the capability of such system to detect leaks, and the safety benefits and adverse consequence of requiring operators to use leak detection systems. A complete analysis would have indicated that a specific standard would provide a specific benefit at a specific cost. Without this data, PHMSA cannot make a decision on the question of establishing standards.

Page 4-3:

The authors reference a paper produced by PRCI on behalf of the pipeline industry. The most revealing statement made about the report is the following: "The report is notable in that there are definite complaints from the technology suppliers over the issues identified in the appendix."

This statement shows a bias toward the use of external leak detection systems. There are valid reasons why industry is not pursuing these technologies in the "long haul pipeline" industry. The technologies are generally most useful in small, restricted areas with adequate power and utilities, such as plant yards. Their applicability to the transmission pipeline industry has not been validated in practice.

Page 4-8

"Leak detection is the first line of defense in the sense that it triggers all other impact mitigation measures that an operator should plan for, including safe flow shutdown, spill containment, cleanup, and remediation. Given that it is the first trigger for all mitigation, a leak detection system that prioritizes rapid detection and high sensitivity is particularly valuable."

However, a leak detection system that is too sensitive and provides too many false alarms for standard operating practices can mask a leak by conditioning the operator over time to assume an alarm is false. This can lead to a larger environmental consequence, especially for larger leaks. This should be stated.

It should also be noted that a Controller {people} really is the true leak detector here, even when accompanied with a CPM leak alarm {technology}. There are no autonomous leak detection systems out there. Per the author's definition, LDS is a function of people, process, and technology. A suggestion: recommend per the LDS definition.

Page 4-17

"One of the most widely used implementations of this technique is trademarked ATMOS Wave by ATMOS International, Inc.,..."

ATMOS International, Inc. may be an upcoming vendor in the technology, but the ATMOS Wave system is <u>not</u> widely used in the U.S. today.

Page 4-18

"Negative Pressure Wave Modeling

A few RTTM explicitly model the hydraulic response that would be expected from a sudden leak to compare this response against the measured pressures, to find a match, and to estimate the size and location of the leak. This requires specialized modeling algorithms and numerical techniques, since the transient pressure wave varies on a much faster timescale and is much weaker than most of the other hydraulics in the pipeline.

A widely used implementation of this method is SimSuite, trademarked by Telvent USA."

This should be validated as documentation does not say this from this vendor.

Page 4-21

"Therefore, even in 1988, these point sensors were delivering sensitivity and time to detection far ahead of any Internal system. Since then the technologies have only improved in performance. "

It would be good to quote some other references here as well.

Page 4- 23

"Acoustic systems can be used effectively on both liquids and natural gas systems."

This should be clarified that for water based systems and gas systems this could be used effectively; for small leaks underground on hydrocarbon liquid pipelines, external acoustic systems are not proven.

Page 4- 24

Hydrocarbon Sensing Fiber Optics

"These systems can be used effectively on both liquids and natural gas systems."

There is not much data on these sensors from research by at least one of the operators; stating that they can be used effectively on liquid and gas systems may be overstating their current maturity. Also, retrofit seems nearly impossible for HCA, ROW, etc. areas.

Temperature sensing cables

Same point, these cables are not well proven for hydrocarbon liquid leak detection.

Page 4-25

"Vapor sensing tubes can be used effectively on both liquids and natural gas systems. "

Works well but only for niche areas.

Page 4-28

“For long leak detection times, for any Internal LDS, the minimum leak that can be detected converges asymptotically to a minimum limit value, the smallest possible leak detection rate. This value mainly depends only on the accuracy of the flow meters and is therefore essentially independent of the LDS method used. A more sophisticated Internal system – a detailed RTTM, for example – will indeed reduce the time to detect a leak of a given size definitively. However, the absolute minimum size leak that can be detected will always be dominated by the instrument accuracy.”

The statement that the minimum leak that can be detected is independent of the LDS method used should be validated. For example, a statistical approach relies less on accuracy and more on repeatability of a meter for leak detection. What about pressure wave based CPM systems?

“This is one of the main weaknesses of an Internal LDS. It is difficult to find flow meters that have reliable accuracies better than about ~ 1%. “

This is an opinion as there are many operators who have meters with better accuracy performance than ~1%. In fact, most custody transfer quality meters have an accuracy specification better than 0.25%.

“Some External systems, like the pigs and balls, can detect pinhole-sized (microliter per second) leaks.”

Perhaps, but they are not real time.

Page 4-34

“External systems, when engineered and deployed well, are typically much more sensitive than Internal Systems.”

As is mentioned earlier in the document, leak detection systems are engineered systems. Generalizations such as these might misled the reader into believing that external systems are typically a more sensitive method. The internal methods may have faster response times, and smaller spill volumes, but they may not detect the same sized leak. Also, the internal methods are primarily dependent on flow measurement instrumentation accuracy and repeatability (see Section 4.8.1 p.4-49) as inputs and that is what might limit the overall sensitivity and reliability, and not the method itself. More useful than the surveys done by the report, which identifies that there is little actual experience with External systems (Figure 4.1, 4.2), are direct comparisons with best-in-class systems on the same pipeline - this would also help with making the capital and maintenance cost comparisons in Table 6.1 more applicable for comparison purposes.

“As a rule, External systems are only useful as leak detection systems. They do not have any of the added operational benefits that many Internal systems provide.”

Authors should qualify here; for example, fiber optics, where a company could use this medium for telemetry, cameras, prevention, etc.

Pages 4-34 to 4-36:

The authors outline several benefits of external leak detection systems without identifying any practical real-world source of operational data. It appears as if marketing literature is quoted to substantiate the benefits of these external leak detection systems. The authors did not quote any real-world example installations where external leak detection systems are installed and operational on long distance cross country pipelines. Industry has found they are not a fit for these types of pipelines due to many factors, including the following: cost, installation problems, ability to test the system, risk to pipeline integrity, safety concerns, pipeline maintenance concerns, and communication issues.

Page 4-37

"A few exceptions include dedicated pressure wave signature pattern recognition systems that do require the installation of field processing units. However, they can usually utilize current pressure transmitters and so sensor installation on the line is avoided."

Experience with several systems shows that they require specialized Pressure Transmitters and in some cases proprietary pressure transmitters to be installed.

Page 4-39

"Distributed temperature sensors rely on extremely small changes in temperature caused by leaks, but also caused by natural geothermal or atmospheric cooling and heating."

According to vendors this is not an issue for false alarms as the temperature change must be very localized (meters) which would not happen for an environmental temperature change over kilometers.

Page 4-43

"Six out of the nine liquids operators (67%) seek to assess this impact on Pressure/Flow monitoring sensitivity. However, none of the operators (0%) actively install extra flow and pressure measurement with the single objective of improving leak detection sensitivity.

With CPM systems, sensitivity and other measures of performance are directly limited by the accuracy of the flow metering. The same six out of the nine liquids operators (67%) seek to assess this impact on CPM sensitivity. However, none of the operators (0%) actively install extra or improved flow measurement with the single objective of improving leak detection sensitivity."

This is inaccurate. Several operators that reviewed this report (including some interviewed by the authors) do install additional or improved flow measurement devices specifically to improve leak detection sensitivity.

The document seems to infer that operators are not doing enough to improve metering for the express purpose of improving leak detection. The issues here as we know them are that the API standards for metering today far surpass the accuracy possible in any of the RTTM systems. Even a bad meter is good to 0.5% and custody meters are very capable of 0.25% of flow. So the reason operators aren't seeking metering improvements to improve leak detection is because current technology already surpasses the uncertainty in flow calculations under pressure.

Page 4-46

"These low counts may simply reflect our choice of operators for interview. Conversations with the suppliers seem to indicate a larger total number of installations. "

The author might want to mention that if the solution is not engineered correctly, it may not be deployed or may be uninstalled from an operator's pipeline.

Page 4-51

"This is often because the results of a pilot are difficult to quantify, compare or test against other options."

Perhaps a certification standard should be adopted so suppliers can truly sell a product that meets a governmental certification.

Page 4-52

"Although there are no false alarms any more, *there are also virtually no alarms of any kind* so at best only large ruptures are reported."

This is not true for all operators' pipelines.

Page 4-53:

Under the "Short Lines" section a statement is made that "The result is that operators currently do not implement any form of leak detection on these short terminal lines".

The above statement is false and misleading. There are operators today that make a concerted effort to install leak detection on short lines leading to tank farms, terminals or other 3rd parties.

Section 5 Task 5: Operational Feasibility - Comments

General Comments for Task 5

The authors should elaborate more on the common operational issues pipeline companies face every day: different fluid operations (oil, refined products, natural gas, and HVLs), short lines versus long lines, lines with varying elevation changes, slackline, etc. Each of these issues have a defined operational state for each pipeline.

Page 5-2

- *"Procedures* that ensure that personnel (including controllers and relevant supervisors and ~~filed~~ [field] personnel if a control room exists or any personnel involved with leak detection in general if there is no control room) utilize the results of the leak detection system appropriately, to maximize its effectiveness." (spelling of "field")

Page 5-7

"Leak detection technologies themselves require minimal maintenance."

CPM actually requires a lot of 'care and feeding' as the system changes, and for general model improvements. Also, the models have a lot of input sources (SCADA, CMT, etc.) which need to be monitored.

"In the Incident Analysis in Task 3 above, a large number of serious losses occur not because the leak detection system fails to give an alarm, but because the controller fails to take appropriate actions in response."

Or the process to validate takes too long.

Page 5-10:

The authors make a general statement without presenting any data to prove the veracity of the statement: "Leak detection system complexity or high cost does not directly translate to better performance."

The data is not provided to show that this is or is not true.

Page 5-13

"Nearly all operators surveyed did believe that their companies had a Corporate Risk Department, but do not know or won't comment on whether corporate risk takes leak detection into account."

Discussion has occurred with at least one operator on their Risk and Overall Risk Department, yet it did not get incorporated into the report.

Section 6 Task 6: Economic Feasibility - Comments

General Comments for Task 6

The authors used invalid assumptions and invalid data in their economic analysis to cost justify leak detection systems. "The Contractor shall perform a cost benefit analysis for deploying leak detection systems on new and existing pipeline systems."

The reason industry does not routinely perform an economic analysis for leak detection systems are the lack of an ability to quantify savings due to risk reduction. The authors attempt to use averages about pipelines and companies to argue that their economic analysis has merit. For example, the mythical 400 mile representative pipeline has a 57% probability of experiencing a major leak over 10 years because there were 201 incidents among 350 operating companies. The two sets of data are not related. Operators are different, pipelines are different. It is simply not possible to assume that a representative pipeline has a specific chance of failing without knowing the operator history or the pipeline history involved. The next step of calculating annual damages for the mythical pipeline is also without merit. In short, there are so many assumptions behind the risk reduction benefit calculation that it is without merit.

The system operating costs are also grossly misleading. For example, table 6.4 indicates that the only system which requires labor to maintain is the RTTM system. This is totally contradictory to industry experience in that every leak detection system requires at minimum an annual review to ensure proper operation. The more likely case is that leak detection systems require constant human maintenance to ensure they are ready to perform as intended.

This is further backed up by the author's own statement on page 2-12: "Objectively, the largest cost element in any LDS is the investment in personnel who understand, manage, plan and improve leak detection within the pipeline company. Any leak detection beyond the simplest of technologies soon requires these experts."

Another location where the authors fail to understand operational costs is in system testing. Periodic testing is required of all leak detection systems as stated in API 1130. The author does not include any costs for this testing, especially for external leak detection systems which cannot be tested unless hazardous product is released external to the pipeline. This type of testing raises the operational costs dramatically.

The end result is that the economic cost/benefit analysis as presented by the authors is not accurate and should not be used to economically cost justify a leak detection system installation.

Page 6-9

The estimate that a leak detection system would reduce the costs of a leak by 75% appears arbitrary and is unjustified by any evidence contained in the study. One of our reviewers believed this may be an order of magnitude too high.

Little data appears in the study to arrive at any estimate of the economic benefit of leak detection systems. An upper limit might be inferred from the data that 46% of above average releases were identified by the control room, indicating that only 54% of above average releases are available to be detected by more or better leak detection. This is at best an upper limit, however, because much of a release typically occurs due to drainage after detection.

Looking at what data is available for the case studies presented results in an even lower estimate of the economic benefit of leak detection. As shown in the following table, these releases were either already detected by leak detection systems, or were pinhole leaks presumably too small to be detected by internal leak detection methods. The table also shows that applying the same benefit to internal and external leak detection is probably misleading.

			Would Event Possibly be Mitigated by Additional:		
Case Study	Operator	Release	CPM	External LD	Comments
1	Enbridge	843444	No	Yes	SCADA & CPM alarms were issued but dismissed
2	Enbridge	158928	No	No	SCADA & CPM alarm, pipeline shutdown, release primarily due to drainage after shutdown
3	TE Products	137886	No	No	SCADA Alarm issued only 2 minutes prior to public report, release primarily due to drainage after shutdown
4	Dixie	130368	No	No	SCADA alarm and public report, release primarily due to drainage after shutdown
5	Sunoco	81900	No	No	SCADA & CPM alarm, pipeline shutdown, release primarily due to drainage after shutdown
6	Exxon	63378	No	No	SCADA & CPM alarm, pipeline shutdown, release primarily due to drainage after shutdown
7	Shell	43260	No	No	SCADA & CPM alarm, pipeline shutdown, release primarily due to drainage after shutdown
6	Amoco	38640	No	Yes	Probably too small for CPM
7	Enterprise	34356	No	No	SCADA alarm, pipeline shutdown, release primarily due to drainage after shutdown
8	Chevron	33600	No	Yes	Slack lines are not amenable to internal CPM during transients
9	Magellan	29998	No	Yes	Probably too small for CPM
		1595758	0	945682	Total
			0%	59%	Percent possibly improved by more LD Technology

Page 6-15

A flaw in the thinking around costs 6.3.5 is the assumption there would be some sort of "magic" infrastructure to power and communicate with instrumentation and sensing cables in only HCA areas and that recurring costs would be negligible. The feasibility to get power and communications, in particular to HCA's around rivers or other remote locations (if permits could be obtained), would be significantly higher than the authors assume.

Section 7 Task 7: Analysis of Leak Detection Standards - Comments

Page 7-17

API 1149 Limitations/ Gaps: API 1149 only covers the following fluids: oil, refined products. It does not cover natural gas and HVLs.

The CSA references in Section 7.2.4 are out-of-date (referring to year 2007 of the standard, not the current year 2011 version, which is significantly different).