Summary of Comments to Leak Detection Draft Report and Contractor Responses

Below is a summary of comments received during the public comment period, and any action taken by the contractors, for the Leak Detection Study Draft Report by Kiefner and Associates/Applus RTD. The original comments can be read in their entirety at the Leak Detection Draft Report comment website: https://primis.phmsa.dot.gov/meetings/DocHome.mtg?Doc=8

Comments were received via the website form via the following individuals/organizations:

- Elizabeth Skalnek, Minnesota Office of Pipeline Safety (MNOPS)
- Tony Collins, Telvent USA, LLC (2 separate comments)
- Shane Siebenaler, Southwest Research Institute

Comments were received by email via the following individuals/organizations

- Richard Kuprewicz, Accufacts
- John Erickson, American Public Gas Association (APGA)
- Philip Bennett, American Gas Association (AGA)
- Peter Lidiak, American Petroleum Institute (API) providing joint API-AOPL comments (AOPL is the Association of Oil Pipelines)
- Gary Hartmann, ExxonMobil
- Dan Regan and Terry Boss, Interstate Nature Gas Association of America (INGAA)

The comments and any action taken by the contractors with respect to changes to the Draft Report, are broken up into two general categories

- Technically substantive comments that resulted in a change by the contractor to the draft report (as well as what the change was)
- Technically substantive comments that did not result in a change to a draft report, but determined worthy of a response/explanation from the contractor

In general for each category, comments directed at specific pages or sections of the report are listed first and in general order of the pages referenced in the comments, followed by more general comments.

Technically substantive comments that resulted in a change to the draft report (as well as what the resulting change was)

Comment: "The Executive Summary should briefly recap some of the major data or "findings" in the various tasks sections. For example, inserting a summary table of the PHMSA database for the 1,337 incident reports (January 2010 to July 2012) filtered down further by 1) on ROW, 2) pipe failure, etc., 3) by detection method(s), probably grouped in columns by hazardous liquids, gas transmission, gathering and distribution, would help one quickly grasp the main thrust of this important and complex work effort. This is going to be done anyway, so I would recommend including it in the Executive Summary for the many readers who never get into the important details within a long report." [Comment Submitted by Richard Kuprewicz, Accufacts]

Response from Contractor and Resulting Change: The contractors agree with this comment, and a summary table has been added to the executive summary, more specifically under "Overall Summary for Task 3" on pages 2-9/2-10.

Comment: "Incorrect Statements from Information Sources.

The authors state that the current regulations in CFR 195 for leak detection would be equally applicable to natural gas pipeline systems. SCADA identify leaks/ruptures in 15% of the natural gas transmission incidents {Page 2-8) vs. 28% for Hazardous Liquids (Page 2-7). Even with this analysis (that does not differentiate the consequences of natural gas transmission pipelines) the authors contradict themselves (Page 2-20).

The authors reference a German Standard (TRFL) regarding leak detection. It was the only Standard that specifically included gases. All of the other Standards currently refer to liquids. He stated that it covers pipelines transporting liquids (flammable and /or water contaminating) and most pipelines transporting gas. He did not specifically state that "gas" means natural gas. However, the German TRFL does not apply to transportation of natural gas for public consumption.

The case studies utilized information from the PHMSA database, but the nuance of the events was not verified by the pipeline companies involved in the incidents. Listed below are some examples of information that was misinterpreted:

* Case Study 2 (TGP Ohio): The shutdown time of 9:55 represents the closing of the last valve to isolate the one valve section that failed (valve 205 to 206). The actual shutdown was when the 204 valve was isolated at 8:59, which shut down two valve sections. This would mean an elapsed time of 11 minutes. Additionally, when personnel arrived at the 205 valve there was not enough pressure to use the operator and the valve had to be manually operated. The reported distance to the two houses that were damaged was from the CAO and is not correct. The actual distances are approximately 200 ft and 540 ft.

* Case Study 7 (NGPL Texas): The pipeline facility name is OE#1 not OE#2. The information from the CAO has some errors. The location of the failure is 1 mile west of station 154 not at the station. The line was returned to service at a reduced operating pressure on 6/28/12.

* Case Study 8 (TGP La): The time to shut down does not reflect the time when the valves were closed. The valves were closed within 37 minutes of the first notification at 3:27." [Comment Submitted by INGAA]

Response from Contractor and Resulting Change: This is a two part comment. In the first part regarding Part 195 applying equally well to gas, a number of commenters also commented on this statement. This statement was removed from the summary as it appeared to cause confusion.   However other language in the report that discusses some of the similar principles in SCADA, CPM, and metering remain.

The second part on case studies for gas transmission is answered as follows. The report uses data that is publically available and filed with PHMSA. The content of the report and the information given were compared. A change was made regarding Case Study 2 for the approximate distances of the property from the failed pipeline. For case study 7 the name was changed from OE#2 to OE#1. No change was made to case study #8. In general, any new information presented by the commenters that was not in the incident reports or varied from the incident reports, particularly if it occurred after the date range provided for the review, was not considered.

Comment: "Page 2-9 the draft states "Releases on gas distribution lines were more likely to ignite and more likely to explode than releases on gas transmission and hazardous liquids pipelines." (Two similar comments submitted.)

"The report should define what they mean by "explode." An unconfined cloud of natural gas can ignite but will not detonate in what is commonly considered an explosion, e.g. generating a shock wave that will cause damage outside of the ignition area. If there is evidence natural gas distribution leaks can cause explosions that data should be presented." [Comment Submitted by APGA]

"Firstly, the term "explode" is not clearly defined and presented in the study. The implication here is an explosion resulting in a shock wave that requires detonation, whereas a natural gas leak may in fact just ignite and not result in an explosion." [Comment Submitted by AGA]

Response from Contractor and Resulting Change: The report is using the terms defined by PHMSA in their instructions for incident reports on gas distribution systems. The summary comments come from a comparison of the ignition/explode responses obtained from hazardous liquid, gas transmission, and gas distribution reports summarized in the project work. The summary report was modified to make it clear that the information is based on what was entered in incident reports filed by pipeline operators.

Comment: "According to the draft report's summary:

1. Leak detection systems are a proven technology on liquid pipelines.

2. "Practically all internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines also." [page 2-10]

3. "The cost-benefit for these systems is typically very good." [page 2-11]

4. "Generally, overall full-lifecycle costs of an LDS are minor compared with other systems on the pipeline: automation and control, metering, inspection and maintenance, for example. The

difficulty lies in convincing operators of their value so that they do not waste their investments." [page 2-12]

5. "Testing, Maintenance, Control Room Procedures, Training and Continual Improvement are the main operational issues that an operator must consider." [page 2-11]

6. "Gas pipelines are given very little guidance with these issues, either by the industry associations or by regulations." [page 2-11]

In other words, a reader of the summary would conclude that leak detection systems are feasible and cost-effective for natural gas distribution systems and it is only the failure of PHMSA and the American Gas Association to provide guidance on operational issues that is holding back the widespread use of this technology in the gas distribution industry." [Comment Submitted by APGA]

Response from contractor and resulting change: This appears to be more of a general comment, not one providing specific recommendations for changes. The contractors also cannot attempt to address how any individual reader may reach conclusions based on the information provided. In general though, the contractors do believe that yes, a lack of standards and certification in LDS is identified as a primary Technology Gap. However, the blame is not placed with anyone in particular. There are, besides, a number of other Technology Gaps. For the most part, there have been no changes to the report in line with the items above. However, in-line with some other comments, there were changes made in the report in a number of places, such as the disclaimer, acknowledging there are a variety of opinions regarding LDS.

Comment: "Only if the reader continues to read the full report does he/she learn that:

1. The potential benefits of LDS are due to potentially faster response times that could result in reduced property loss. [page 6-9]

2. No reductions in deaths or injuries are projected from the use of LDS in distribution [page 6-9]

3. Distribution incidents where leak detection systems are operational have on average slower response times than incidents where no LDS is operational. [page 3-93].

4. Average response times for distribution incidents with no LDS was 0.2 hours (12 minutes). [page 3-93]

5. Despite the fact that incidents with LDS report a slower response time, the report assumes a 75% reduction in property loss for distribution incidents. [page 6-9]

Obviously someone reading just the summary will get a grossly distorted picture of the feasibility, potential costs and potential benefits of LDS on distribution systems." [Comment Submitted by APGA]

Response from Contractor and Resulting Change: There are multiple comments to this effect - particularly to the "75% benefit of improved LDS" to ultimate damage. We suggest that at least 75% of a historical spill has indeed, on average, occurred before the operator knows about it. However, we have stated twice that the reader should follow this, or a similar, procedure for his own pipeline and situation rather than accepting these numbers as gospel. The important issue is to have a firm order-of-magnitude benefit per year estimate in mind. The contractors suggest: LDS is worth in the order of magnitude of $100,000's per year - not $10,000, nor $1,000,000 - on an average 400-mile pipeline. In general, there were some modifications to the report, particularly with certain caveats repeated and strengthened in an attempt to convey these are just some examples, operators need to perform and analysis specific to their system and operating conditions, and overall opinions on LDS differ.

Comment: "On page 2-11 the draft states "Testing, Maintenance, Control Room Procedures, Training and Continual Improvement are the main operational issues that an operator must consider… Gas pipelines are given very little guidance with these issues, either by the industry associations or by regulations." Taken out of context this is a very misleading statement. The reason there is little guidance for LDCs from either trade associations or regulations is 1) 90% plus of LDCs have no SCADA or control room for which testing, maintenance, procedures and improvement could be applied. Furthermore, there is no feasible technology for automatic detection of leaks on interconnected, networked distribution systems. Neither is there technology for automated or remote shutdown of such systems. The authors offer not one single example of a successful application of LDS technology to networked, interconnected distribution system. Virtually every statement in the draft report regarding distribution systems lacks any factual basis, and rather relies on the opinion of the authors. This statement should be deleted." [Comment Submitted by APGA]

Response from Contractor and Resulting Change: Similar to another comment and response, the contractors acknowledge low-pressure distribution systems, and in general any distribution system that is not on SCADA, are not covered in detail in this report. Text was revised to state that LDS on low pressure distribution systems is not covered by the report. The third paragraph under section 4.6 was revised, particularly regarding any segments that might be subject to EPA leak detection standards.

Comment: Multiple comments raised issue with the statement in the summary on page 2-12 (Overall Summary of Task 7) that states "In our opinion many of the leak detection regulations in 49 CFR 195 – especially expressions of principles and procedures – apply in large part equally well to gas pipelines"

Response from Contractor and Resulting Change: Based on the amount of comments received, and the overall confusion and scrutiny this statement appeared to cause, the statement by itself and as a first bullet in the summary was removed. In general though, the authors do believe that any CPM generally requires a SCADA system, metering, instrumentation, etc. So, a complete system, regardless of the type of product being transported, requires these general prerequisites. Language elsewhere in the report that talks about these similar concepts remain, however, the authors did attempt to avoid any other direct comparisons between gas and liquid that might cause confusion.

Comment: "That rupture detection objective of "immediate" should be changed to detect "quickly." The science of fluid and thermodynamics places absolute time limits, or boundaries, on how rapidly rupture releases can be detected by remote computer systems, and these technical limitations will, in all probability, prevent immediate remote detection. Accufacts believes it is very important to identify pipeline ruptures as rapidly as possible, but the word "immediate" sets up the industry, the regulators, and the public for unrealistic expectations that clearly violate the laws of science, no matter how well meaning the intent." [Comment Submitted by Richard Kuprewicz, Accufacts]

Response from Contractor and Resulting Change: The contractors agreed with the commenter and wording has been revised in a number of places to reflect the issue raised, for instance on pg. 3-19.

Comment: "On page 3-17, item 4, I highly recommend the statement that "refined products are liquids inside the pipeline and remain liquids when released from the pipeline" be modified to "usually" remain liquids when released (or something along these lines). It is Accufacts' experience that this draft statement is technically incorrect, and could be easily and dangerously misunderstood by less experienced readers." [Comment Submitted by Richard Kuprewicz, Accufacts]

Response from Contractor and Resulting Change: The contractors agree, and changes to the text were made. The language now appears on page 3-21, but still item 4 under Section 3.5 Big Picture.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: These 3 comments have been addressed in other comments, and some changes to the report have been made. For clarification, the following responses are given.

1. This first point has negligible impact on the data summary.

2. This point is there in the report for people to identify, as API/AOPL have done. Words have been added to the report to tell readers that Task 3 is simple presenting data.

3. KAI did analyze the decline in the average spill size. The report is not about spill size but about spill detection. Prior data showed a larger maximum release than was observed for 2010 to 2012. This could also be responsible for the higher average spill size for 1986-2004 compared to 2010 to 2012.

Words are added to the report covering points 1 and 2. On point 3, the comparison with 1986-2004 has been removed on the basis it does not add much value. What is important is how effectively leaks are detected in the industry today.

Comment: "Incomplete Understanding of the Various Energy Segments including Natural Gas Transmission Pipelines: The Draft Report does not adequately describe the variety of configurations, modes of operation, risks and consequences of these separate segments of the energy pipeline infrastructure. This distinction is very important from the standpoint of public safety and environmental impact. The problem is accentuated by the authors' assumptions to address ruptures and leaks as a composite; that is, to consider them as equal. (Page 3-15)." [Comment Submitted by INGAA]

Response from Contractor and Resulting Change: The report is not tasked with describing the configurations, modes of operation, risks and consequences (consequence is a component of risk and not separate from risk) on the separate segments of the energy pipeline infrastructure. Readers wanting to know the differences between hazardous liquids, gas transmission and distribution will need to find an alternative source for this information. In general though, text was revised to state that ruptures and leaks are not treated as equal.

Comment: "Incomplete Understanding of the Probabilities and Consequences of Incidents on Natural Gas Transmission Pipelines: On natural gas transmission pipelines, the identification, mitigation and consequences of ruptures are distinctly different than leaks. This lack of distinction in this report (Page

3-16) results in a comparative analysis of the transportation modes that does not account for the different risk and consequences of the incidents.” [Comment Submitted by INGAA]

> **Response from Contractor and Resulting Change:** Again there appears to be confusion over the use of risk and consequences. It is thought the authors mean to use the words likelihood of failure and not "risks". The report is not tasked with summarizing and reporting threats and consequences. The report is about leak detection, which includes the detection of ruptures and leaks and not any differences between the two as far as consequences are concerned. Large volume leaks and ruptures are covered but from the point of view of detection and nothing else. Text has been added in various places to clarify the purpose of the report, particularly in the Introduction and Summary Sections.

Comment: “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.” [Comment Submitted by API-AOPL]

> **Response from Contractor and Resulting Change:** The numbers match but the word operational in paragraph 3 of page 3-28 was changed to functional. This was overlooked during the finalization of the report.

Comment: (page 3-61) ExxonMobil Pipeline Co. Case study

> “The report states "The downstream valve was a check valve. This closed 2 hours and 56 minutes after the control recognized a failure had occurred."

> Since a check valve is a self-acting valve not needing controller action, the reference to it being closed after the controller recognized a failure is incorrect. While the following information was not requested by the Form 7001, EMPCo can confirm that the check valve was operating correctly and held pressure when subsequently tested. The valve closed when the line lost pressure during the incident. [Comment Submitted by ExxonMobil]

> **Response from Contractor and Resulting Change**: The comment in the report about the check valve closure was deleted.

Comment: (page 3-61) ExxonMobil Pipeline Co. Case study

> The report states that the inventory for the isolated 1,709' section is 166,132 gallons. The report should be corrected to state that the inventory for the section in question is 10,214 gallons. [Comment Submitted by Exxonmobil]

> **Response from Contractor and Resulting Change**: The report wording was revised to reflect the 10,214 gallons advised by ExxonMobil.

Comment: **"**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." [Comment Submitted by API-AOPL]

> **Response from Contractor and Resulting Change**: The wording for the first issue noted by the commenter is missing a "not" to make the sentence a negative statement. This was corrected in the final report. Wording was revised so that the first issue now reads "SCADA and CPM did not alert the pipeline controller to shut down the pipeline.

Comment: "Flawed Statistical Analysis of Natural Gas Transmission Pipelines: Major statistical errors have occurred in the report. The authors have utilized average as a statistical measure in some of the analysis where the data is definitely skewed (e.g. 3-75); i.e., non-normal distribution. The statistical analysis technique recommended by experts for skewed data is use of median rather than average. INGAA recommends the authors reassess their statistical analysis techniques throughout the report to reflect appropriate statistical analysis." [Comment Submitted by INGAA]

> **Response from Contractor and Resulting Change:** In the contractors' opinion, no major statistical errors have occurred in the report. The average, median and mode for a symmetrical distribution all have the same value. For non-symmetrical distributions of values (e.g. release volumes), average, median and mode do not have identical values. For the non-symmetrical case, the 3 values provide more information about the range of values being studied than in a symmetrical distribution. That is the use of all 3 measures. However, the median is simply the middle value of the range of values being considered. For the release volumes being considered, the median is a smaller number that the average. The mode is the value that occurs the most often in a set of values. What should be done and what was done in the report is to identify how many values are being considered, the basis of the selection for the values, the maximum and minimum values, the quantity below and above the average (or the median if this is chosen) and sum or "weight" of the values below and above the average (median). In this report average was chosen to identify a number of large volume releases for summary and case studies. If the median had been used, the number of releases being considered would have grown and releases with smaller volumes would have been included. The report does not hide the fact that most of the release volumes reviewed were small volumes. Median and mode values were added when the averages were stated for hazardous liquids and gas transmission. This provides the reader with additional measures describing the range of release volumes being reported by the pipeline operators on the incident reports.

Comment: Section 4.3.2 of the report discusses API 1155 which has been withdrawn. Relevant sections of API 1155 are now included in Annex C of the latest edition API 1130 dated September 2007. [Similar Comments submitted by Tony Collins, Telvent; and API-AOPL]

> **Response from Contractor and Resulting Change:** The following note has been added in the portion of Section 4.3.2 (pg 4-4 to pg 4-5) discussing API 1155: "(This has now been withdrawn as a standard. Relevant sections of API 1155 are now included in Annex C of the latest edition

API 1130 dated September 2007)." There is also additional language to acknowledge the withdrawal of API 1155 in other sections of the report, such as page 7-12.

Comment: "On page 4-3, there is a sentence: "The report is notable in that there are definite complaints from the technology suppliers over the issues identified in the appendix." That statement is very misleading (and also incorrect). The testing was performed based on configurations supplied by each vendor. After they reviewed the data, there were given an opportunity to say, "If we had instead changed parameter X to value Y, this is the change in results." It was simply an opportunity for them to give some context to their results. None of them complained about the quality of the results in the body of the report." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: The wording has been revised to read "The report contains remarks from the technology suppliers regarding the issues identified with the technologies, and the field measurements, in the appendix."

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: The authors agree with many of the points raised by the commenter. Edits were made to the report on pg. 4-8 and in chapter 5 to try to repeat and emphasize some observations in-line with some of the points made by the commenter, and also emphasize overall that leak detection systems are a combination of people, processes and technology.

Comment: "On page 4-23, the authors are mixing-and-matching two different technologies and calling them the same thing. There are two types of discrete acoustic systems: negative-pressure wave and use of microphones. Most of this section of the report refers to the latter. However, statements about pairing the transmitters to filter noise only apply to the former." [Comment submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: Wording has been revised, and this distinction is clarified in the appropriate section of the text on pg. 4-23.

Comment: "On page 4-24, DTS is said to be widely used in down-hole leak detection. That is not correct. DTS is used for well logging and gas lift applications; its use is in characterizing thermal profile in bore or annulus, not leak detection." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: The contractors believe Distributed temperature sensing (DTS) is used for a variety of downhole production well applications. The language in the text on page 4-24 has been revised slightly to provide some clarity on application on use in downhole applications.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: The authors feel this is a good point. Language has been added to emphasize that an LDS can be as simple as plain visual inspection with aids such as video, infrared, etc. This is noted in the report; the observation is repeated and emphasize. Additional edits were made in certain areas of the report such as in Section 4.4.2 on page 4-35.

Comment: "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." (Two comments submitted related to this statement)

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.” [Comment Submitted by API-AOPL]

That statement is incorrect. While some of them can detect small changes, what they are really eyeing a large changes in temperature” [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: A good point was raised by the commenters, and it is true of many "distributed" LDS arrays. A baseline "map" of original HC concentrations is built upon commissioning, and the sensors look for deviations from this map. This general feature of LDS arrays is added to the text on pg. 4-22. Other slight changes were made to the referenced text on (now page 4-40), which now reads “Distributed temperature sensors rely on changes in temperature that may be caused by leaks, but may also be caused by natural geothermal or atmospheric cooling and heating. “

Comment: “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.” [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: Agreed. Another comment to this effect is added. The observation is repeated and emphasized in various sections of the report, including through additional language in Section 4.8.2 on page 4-52: “We note below under Technology Gaps that perhaps a certification standard should be adopted so suppliers can truly sell a product that meets an industry-wide certification.”

Comment: “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.” [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: This is meant as an extreme case. The wording is softened to make this clear, and now reads “Although there are no false alarms any more, *there are also very few alarms of any kind* so at best only large ruptures are reported.”

Comment: “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” [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: Wording has been revised to add the word "often", so the statement now reads "The result is that operators currently often do not implement leak detection on these short terminal lines."

Comment: "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")" [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: Spelling has been corrected.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: All these maintenance items are part of the system, not the technology. To make this clear, we have added italics. The very next sentence lists these system maintenance items already.

Comment: "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" [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: The wording "does not directly" has been changed to "does not necessarily" which is true in the opinion of the authors.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: The appropriate section has been revised. There was indeed one. It now reads "Nearly all operators surveyed did believe that their companies had a Corporate Risk Department, but all but one do not know or won't comment on whether corporate risk takes leak detection into account."

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: This is a comment similar to others. The contractors believe they have been clear in the report that cost figures are only order-of-magnitude, and a variety of opinions on numbers are out there. There has been no change specifically to the cost numbers provided in the report. However in line somewhat with this comment and others raising concern with the cost benefit analysis portion of the report, some language has been added (for instance on pages 6-7 and 6-9) to try to be more clear that any operator will need to perform a specific, targeted benefits analysis for their own pipeline using actual percentage figures and cost basis appropriate to their situation and operational targets.

There is also language added elsewhere, such as in the disclaimer acknowledging there are a variety of opinions surrounding LDS.

Comment: "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 [provided in comment], 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." [Comment Submitted by AP-AOPL. Similar comment on this value also submitted by INGAA]

Response from Contractor and Resulting Change: There are multiple comments to this effect. We suggest that at least 75% of a historical spill has indeed, on average, occurred before the operator knows about it. However, we have stated twice that the reader should follow this, or a similar, procedure for his own pipeline and situation rather than accepting these numbers as gospel. The important issue is to have a firm order-of-magnitude benefit per year estimate in mind. The contractors suggest: LDS is worth in the order of magnitude of $100,000's per year - not $10,000, nor $1,000,000 - on an average 400-mile pipeline. In general, there were some modifications to the report, particularly with certain caveats repeated and strengthened in an attempt to convey these are just some examples, operators need to perform and analysis specific to their system and operating conditions, and overall opinions on LDS differ.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: Text in the report was modified to make these observations.

Comment: "Page 7-17: 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)." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: Text in the report was modified to make these observations, and update the references.

Comment: "APGA hoped that PHMSA would use this report to explain to Congress the significant differences between leak detection on the various types of pipelines that PHMSA regulates, namely:

1. Linear, long distance, high pressure pipelines transporting liquids with varying compressibility (hazardous liquid)

2. Linear, long distance, high pressure pipelines transporting compressible gases (interstate gas transmission),

3. Relatively short, linear or interconnected, high pressure pipelines transporting compressible gases (gas transmission lines operated as part of distribution networks), and

4. Relatively low pressure, interconnected natural gas distribution systems

Unfortunately the report provides data about leak detection systems (LDS) for the first two types of pipelines but only offers unsupported speculation for LDS on distribution pipelines and transmission lines operated as part of distribution networks. Without any support, the authors offer their opinion that LDS designed for long, linear pipeline systems should also work and be cost effective on interconnected, networked transmission and distribution lines operated by distribution operators" [Comment Submitted by APGA]

Response from Contractor and Resulting Change: The contractors cannot address recommendations to PHMSA. In general the contractors do agree with other aspects of the comments related to the study itself and acknowledge that the report does not cover relatively low-pressure distribution systems in detail. Text was revised to state that LDS on low pressure distribution systems is not covered by the report. The third paragraph under section 4.6 was also revised, particularly regarding any segments that might be subject to EPA leak detection standards.

Comment: "Incomplete Analysis of the Existing PHMSA Data on Natural Gas Transmission Pipelines.

The Draft Report is one of the first publicly available reports that utilize the improved information provided by the 2010-12 PHMSA incident and annual reports. While the lack of long term trending is missing in this report because of this explicit choice to use the 2010 to 2012 timeframe, the richness of the dataset permits a more robust statistical analysis.

Unfortunately, the authors have not taken full advantage of that information. In some cases, the authors utilized single variable analysis to describe behavior that is clearly a function of many variables. Data are available in the dataset to conduct multivariable analysis. The response times to an incident are clearly a function of the type of release (leak vs. rupture) and the presence of operating personnel on the site when it occurs. In choosing to do a simplified analysis, and failing to fully utilize the more robust data results in possibly inaccurate or unnecessarily conservative conclusions and recommendations." [Comment Submitted by INGAA]

Response from Contractor and Resulting Change: Long term trending is not considered relevant to the report objectives. Knowing if leak detection has improved over the last 10 years does nothing to alter the situation presented by incident reports filed by pipeline operators over the last 30 months. There was no need to do a "more robust" statistical analysis of the data to satisfy the requirement of the report.   However, text has been added in various places to clarify the purpose of the report, particularly in the Introduction and Summary Sections. Text has also been added indicating that readers wishing to perform a more detailed assessment of the publically available incident reports are free to do so.

Comment: **"**Flawed Cost Assumptions for Natural Gas Transmission Pipelines

Natural gas transmission pipeline systems are considerably more complex piping systems than hazardous liquid pipelines (e.g. multiple inputs, multiple outputs, looped and parallel pipelines, interconnections between parallel lines, and a compressible fluid. The authors numbers, based upon a specific number of dollars per foot or per installation, do not take into account the complexity that would be required on natural gas transmission pipeline For example a recent replacement of a SCADA system was estimated at $12 M without in-house labor factored in. That estimate is substantially different than the $1 K that the author is depicting for leak detection system. Again it appears that the authors' experiences with leak detection systems on natural gas transmission pipelines are limited." [Comment Submitted by INGAA]

Response from Contractor and Resulting Change: This is partly a repeated comment. However, there is an analysis of having to add a SCADA system from scratch just for LDS. For a 400-mile pipeline this is not $2 million or even close. Naturally, the ROI if a new SCADA system is needed is lower - however, this is already fully covered in the analysis. In general though, and to help address a number of other comments on the cost benefit analysis, caveats were repeated and strengthened in the report in a variety of places in an attempt to clarify.

Comment: "The report collates data that can be used for analysis of leak detection effectiveness. There are a number of weaknesses in the actual data analysis provided. For example, the report does not segregate low consequence events. Reports for less than 5 barrels, no impact to water, no death, injury, fire or explosion, and property damage of no more than $50,000 do not require an answer to the questions on the presence of CPM systems or SCADA. The report interprets this as a poor response rate by pipeline operators and uses this interpretation to extrapolate data points. In another example of flawed data analysis, the report compares 1986-2004 PHMSA incident records with the mid-2010 to 2012 records. In this comparison the average reported leak size was lower in the later data set. The report does not recognize the reason for the difference in the average spill size in the two data sets is the fact that the minimum reporting size for a leak went from 50 barrels in the period before 2002 to 5 gallons in the period starting in January 2002. The report goes on to use this data comparison to validate a number of the report's assumptions about operator leak history. These and a number of other flawed uses of the PHMSA incident data are used to support various conclusions or extrapolate new data points. The problems with the data analysis lead to problems with some of the report's conclusions." [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: In the opinion of the authors, there is nothing in the report that represents flawed use of the PHMSA incident report data set for 1986-2004 and 2010 to 2012. The report also does not make any conclusions. The report presents data in an easily presentable form for industry to assimilate and comprehend, as well as other concerned readers. It was not the intention of the project work to separate data to present summaries in areas not directly related to leak detection. Property damage would be a good example of such an area not relevant to detection of a release. Neither were low consequence events a data type that needed to be identified and reported on. The response summaries are per the operators data filed with PHMSA.

There is no extrapolation of data in the report and it is not understood why the commenters think any of the data is extrapolated. This would be an incorrect interpretation of the wording of the draft report. The comment has been made that the higher reporting threshold for data 1986 - 2004 is responsible for the higher average. This comment ignores the much higher release volume that was reported during this period compared to the highest release volume reported for 2010 - 2012. T he much higher release volume for 1986-2004 will have an effect on raising the average release volume calculated for 1986-2004. In fact, the draft report merely states what the average and the maximum release volumes were for 1986-2004. The only comparison between the two data sets is that for the ratio above average release volume to those below the average release volume. The ratio was the same in both periods.

To avoid any potential confusion and given the small amount of information provided on the 1986-2004 period, it has been deleted. Changes were made to the report to describe the information provided by pipeline operators where the release volume was low. The changes made address the concerns on no "data" as made by the commentators. The references to the 1986-2004 incident records were removed from the report. This is not because the data are necessarily incorrect but this data and its summary do not have to be part of this report.

The report has been modified so that readers can fully appreciate the scope of the work and the purpose of the work and not expect the report to be an in-depth evaluation and analysis of the 2010 to 2012 incident report records in areas not necessary for this project on LDS.

Comment: “The report attempts to categorize and then explain various leak detection technologies. In a number of instances the report confuses leak detection technologies with leak detection products. The section on external leak detection is a catalog of commercial products being marketed to the pipeline industry. The performance metrics stated in the report for external systems are not attributed to any independent source. The report does list the numerous drawbacks of these types of systems in cross country pipeline applications. Then the report makes assumptions in the return on investment calculation section that do not take into account the cost of the very drawbacks reported early in the report for these systems. The different treatments for this issue in different parts of the report add to confusion over the practicality of leak detection methods.” [Comment Submitted by API-AOPL]

Response from Contractor and Resulting Change: We only make a very few references to vendors when they are the only source of an exotic technology - and we never refer to any specific External LDS. There was one instance where a vendor was still listed, but the reference to that specific vendor has been removed.

Comment: "There are numerous places in the document in which specific performance levels (e.g. "0.03 gpm") are provided, but these numbers are not sourced. These claims read as absolute fact instead of in the context as the result of one paper. References need to be added." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: In general any references to volume sensitivity were from an EPA study EPA-510-S-92-801 (May 1988.) This study is referenced in a couple sections of the report, such as page 4-21 (previously existing), added to page 4-26 (under Chemical Vapor Sensors,) and page 4-28 (talking about External Systems.)

Comment: "Numerous "fact statements" (e.g. "This technology is effective…") are, in most uses in this report, actually opinions. Changing them to add context such as, "This technology theoretically should be able to…" is more correct." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: No direct references to pages or sections were provided in this comment. In general, such wording has been revised in several places where appropriate. Additional language was also added in the disclaimer acknowledging there is a diversity of opinion with regards to LDS.

Comment: "The bibliography is missing several papers that were referenced in the report. For example, two different PRCI reports were explicitly noted in the text, but only one appears in the bibliography." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: The bibliography has been updated.

Comment: "There is inconsistency on references to specific vendors. Some CPM section refer directly to trademarked products, which that methodology is not used widespread in the report." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor and Resulting Change: Only examples of CPM vendors were cited in the draft report, and only when they are virtually the only examples of the technology. This is intended as guidance to the reader, not any special endorsement of the technology or vendor. There was one vendor mentioned that other commenters raised issue with as well, namely whether or not that vendor was widely used. To help address that comment and in part to help address this one, that specific vendors name was removed, and the technology discussed in more general terms.

Technically substantive comments that did not result in a change to a draft report, but determined worthy of a response/explanation from the contractor

Comment: "A simple Table should be added to the report, at least for gas and liquid transmission pipelines, that summarizes the 30-month database by ruptures vs leaks utilizing the term rupture in pipeline fracture mechanics (big holes). While Accufacts can understand the draft's approach to avoid distinguishing between leak and ruptures, it has been our experience that leaks may or may not leave the pipeline right-of-way, but ruptures always leave the right-of-way. The public may seriously challenge the failure to distinguish somewhere in the report, the differences between pipe fracture mechanics rupture and the slower rate leak releases, especially for liquid pipelines." [Comment Submitted by Richard Kuprewicz, Accufacts]

> **Response from Contractor:** The pipeline operator determines the release type to report. It was not possible for the authors to validate whether each release correctly corresponds with fracture mechanics definition of rupture. This is also not the definition given by PHMSA in the instructions for incident report completion. There has been no change to specifically add a table as suggested by the commenter, however, it should be noted Tables 2.1, 3.1 and 3.2 list the numbers of ruptures and leaks for the 3 incident reporting categories. The numbers of leaks and ruptures in the above average release volume sections for hazardous liquids and gas transmission are also listed for these specific data sets.

Comment: "The draft report is fatally flawed in virtually every section where LDS for distribution is discussed. Page 2-8 of the draft states that:

> "The overall technical issues identified from the work performed on Task 3, based on data reviewed between January 1, 2010 and July 7, 2012 for natural gas transmission pipelines were:
>
> 1. The pipeline controller/control room identified a release occurred around 16% of the time.
>
> 2. Air patrols, operator ground crew and contractors were more likely to identify a release than the pipeline controller/control room.
>
> 3. An emergency responder or a member of the public was equally likely to identify a release as an air patrols, operator ground crew or contractors.
>
> 4. SCADA was the leak identifier in 21 (15%) out of 141 releases where a SCDA was functional at the time of the release.
>
> 5. For gas transmission pipelines, SCADA did not appear to respond more often than personnel on the ROW or members of the public passing by the release incident.
>
> 6. Large distances between block valves may also have been a contributory factor in the size of the release.

7. For 92 incidents along the ROW where a leak/rupture occurred in a pipe body or pipe seam, there were 22 incidents above the average volume release and 70 below the average volume of 23,078 MSCF.

8. The chances of having an above-average release volume were around 1 in 4. That is a release volume greater than around 23,078 MSCF.

9. For 40 out of 101 incidents the pipeline shut down time was between 5 minutes and 1 hour.

10. For 61 out of 101 incidents the pipeline shut down time was longer than 1 hour."

The draft does not state how many of these incidents involved long-line, linear, actual transmission pipelines and how many involved gas distribution pipelines that are classified as transmission because of the operating pressure or the function of the pipeline. As APGA has previously pointed out to PHMSA, "transmission" pipelines operated by distribution systems bear little or no resemblance to real transmission lines. Many are less than 4 inches diameter and may operate at less than 1 percent of SMYS. The report should differentiate between different types of "transmission" pipeline – those that are true transmission lines and those operated as part of distribution systems." [Comment Submitted by APGA]

Response from contractors: The text quoted by APGA from Page 2-8 is for gas transmission and not for gas distribution. There is separate text in the report in section 2 for gas distribution. The 10 points quoted are for gas transmission and gathering incident reports. It should also be noted, and has been clarified in the report, that the contractors also performed the analysis based on the information reported by operators. The contractors stand behind their analysis based on the information provided in the reports. The contractors are not responsible, nor did they have the time or resources to independently verify whether this information reported by the operators was accurate. Several caveats to this respect are made throughout the report. No changes have been made specific to the comment.

Comment: "Also on page 2-9, the draft states that "The pipeline controller/control room identified a release occurred less than 1% of the time." It should be noted that the vast majority of distribution operators (probably over 90%) do not have control rooms or SCADA systems." [Comment Submitted by APGA]

Response from contractors: The summary is describing the outcome of reviewing incident reports submitted by gas distribution operators. No change has been made to the report.

Comment: "On Page 2-9, the study further states "Practically all internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines also. Because of the much greater compressibility of gas, however, their practical implementation is usually far more complex and delicate". Here there is a clear over-generalization of the term "gas pipelines" which negates the differences between linear transmission pipelines and distribution lines that are networked and interconnected." [Comment Submitted by AGA]

Response from contractors: The authors believe they are clear on what it is or is not covered in the report. The only segments of LDC systems that are covered are intermediate pressure rings. Low/medium pressure distribution systems, and in general any distribution system that is not on SCADA, are not covered by this report. In-line with another comment from APGA more directly related to low pressure distribution systems, text was revised to state that LDS on low pressure distribution systems is not covered by the report.

Comment: "On page 2-10 the draft states "Practically all internal LDS technologies applicable to liquids pipelines apply equally well to gas pipelines also. Because of the much greater compressibility of gas, however, their practical implementation is usually far more complex and delicate."

Not one shred of evidence is presented in the report to support this statement. It is solely the opinion of the authors. APGA is not aware of any internal LDS technology applicable to networked, interconnected distribution systems or to transmission lines operated as part of a networked, interconnected distribution system. These systems typically have neither pressure sensors nor flow meters anywhere but receipt and delivery points. Few, if any, of the pressure and metering points are telemetered in real time – most customer meters are read monthly, therefore real time LDS based on input and output is impossible. Even if real-time flow measurement were available, performing a mass balance on a interconnected, network of distribution pipelines transporting a compressible fluid (natural gas) would require detailed special and temporal pressure, temperature and gas compositional data in order to compute local real (as opposed to ideal) gas densities. The computing power necessary for such real-time density calculations over the millions of miles of distribution piping would require a quantum leap in supercomputing." [Comment Submitted by APGA]

Response from Contractor: The contractors disagree with this comment and stand by the observation that: (a) yes, gas CPM works in most cases in exactly the same way for liquids systems; (b) in fact, a number of gas pipeline operators do use it; (c) the obstacles to its widespread use are instrumentation, and engineering effort devoted to implementation. There are caveats already in the report that do note differences in gas vs. liquid. No change has been made to the report.

Comment: "The entire discussion of economic feasibility in chapter 2 lumps distribution in with transmission and hazardous liquid pipelines. APGA has no knowledge of hazardous liquid pipeline operations and only knowledge of gas transmission operations as it applies to transmission lines operated as part of a distribution system. The statements that the "cost-benefit for these systems is typically very good" is ludicrous and not one shred of supporting evidence is offered to support this statement. The report fails to identify any technically and economically feasible leak detection system for distribution pipelines or transmission pipelines operated as part of distribution systems. This entire section should be deleted." [Comment Submitted by APGA]

Response from Contractor: We stand by the comment that basic, carefully implemented leak detection - on high and intermediate pressure gas pipelines - has an extremely high return on investment (ROI.) Better, in most cases, than the elaborate and expensive disaster mitigation programs.

Comment: [Section 3, Incident Review] **"**It appears the Report's authors utilized a preliminary version of EMPCo' s PHMSA Form 7001 for this incident and not the Supplemental Final report submitted on September 6, 2012. The report should be updated to reflect the information submitted in the Supplemental Final report.

As the Supplemental Final report states, the line was shut down at 22:48 Mountain Time on July 1,2011. The Form 7001 data available online on PHMSA's website does not include the narrative portion EMPCo's Form 7001 submission which includes the statement "4. In reference to A4 and A18a - EMPCo Controller noticed equipment changes and pressure loss at 22:40, positive confirmation of the accident occurred at 23:45 when EMPCo received notice from Laurel emergency responders." This is the explanation for what would otherwise appear to be a discrepancy in the time of incident detection (23:45) being after the time of shutdown (22:48)." [Comment Submitted by ExxonMobil]

Response from Contractor: The comment is noted, but the cut-off date for incident reports was July 7, 2012, which is mentioned in a number of areas of the report. No change has been made to the report related to this comment, as it related to a Supplemental Report after the cut-off date.

Comment: "Figure 3.37 Gas Distribution Releases, Initial Identifier will be used to suggest distribution control room management rules need to be improved to improve leak detection capabilities, when, in fact, few, if any, distribution systems have SCADA systems capable of detecting leaks on networked distribution systems. However on page 3-93 the report notes that "[t]he average time to respond for those incidents where SCADA was functional is 0.4 hours… Where SCADA was not functional (most of the incidents), the average response time was 0.2 hours." [emphasis added] APGA challenges the earlier statement that LDS is cost effective, when the data shows that SCADA does not increase the response time to distribution incidents. Such a contrary result ought to call into question the entire analysis of distribution LDS." [Comment Submitted by APGA]

Response from Contractor: Data and summary refers to incident reports provided by operators with gas distribution systems. No changes were made to the report.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor: This part of Task 3 requires conclusions and recommendations to be given in the report. Drawing conclusions was not a requirement of this Task 3, or the project as a whole. It is a matter of conjecture whether the authors failed to undertake a study of sufficient depth. Information was provided for readers interested in this aspect to draw an initial conclusion**.** No change was made to the report directly related to this comment.

Comment: **"**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." [Comment Submitted by API-AOPL]

Response from Contractor: The requirement for the report was to be technically descriptive in nature. Recommendations were not required or given.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor: The commentator references inconsistency with some numbers on page 3-24 with those in the previous section. The commentator does not provide sufficient information on what is inconsistent. The authors have reviewed the wording and the numbers in Tables 3.1 and 3.2 and can find no inconsistencies. "The previous section is 3.6 Specific Data Selected for ROW Assessments". This entire section is there to help the reader transition from a section where the numbers are to do with all incident reports between 2010 and 2012 to a section (3.7) to with ROW incidents only. No changes made to the report.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor: Regarding the difference between operating and functioning in Table 3.3 for SCADA and CPM of one in each case, the numbers reflect what pipeline operators submitted in their incident reports to PHMSA. The authors didn't feel it was necessary to comment in one unit difference in each case as the numbers used to document the position with SCADA and CPM for releases was the "functional" category and this was higher number in each case.

For the second part of this comment, the commentator is referring to numbers for SCADA and CPM. The statement is then made that the numbers do not match the table. This is Table 3.3. The numbers and the wording have been checked and they do match. No changes made.

Comment: "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,"…)." [Comment Submitted by API-AOPL]

Response from Contractor: The authors did not understand the remark or see where a clear and specific enough recommendation for change was given. No change made to the report.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractor: The contractors actually agree - setting Standards and Certifications for LDS is identified as a major technological Gap. However the report explicitly avoids making a recommendation for new standards or regulations.

Comment: "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.” [Comment Submitted by API-AOPL]

Response from Contractor: The contractors disagree with this comment and stand by the observation that External LDS as part of an overall engineered system approach are being ignored by the industry for non-technical reasons.

Comment: “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.” [Comment Submitted by API-AOPL]

Response from Contractors: This has been verified and in the authors opinion did not require a change in the report. Also, the authors tried to avoid mentioning any specific vendors. Even one that was previously listed in the draft and considered to be widely used has been removed for consistency.

Comment: “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.“ [Comment Submitted by API-AOPL]

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

Response from Contractors: Other references are already listed in the bibliography.

Comment: “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.” [Comment Submitted by API-AOPL]

Response from Contractors: The authors disagree. There are in fact multiple tests of acoustic systems on liquids systems underground. No change was made to the report.

Comment: "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." [Comment Submitted by API-AOPL]
>
> **Response from Contractors:** The comment appears to be more opinion rather than technically based. No changes were made to the report.

Comment: "Page 4-25 "Vapor sensing tubes can be used effectively on both liquids and natural gas systems. "

> Works well but only for niche areas. [Comment Submitted by API-AOPL]
>
> **Response from Contractors:** The comment is noted but appears to be more opinion. No changes were made to the report.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: For the first part of the comment, the authors feel they have been clear with caveats and any limitations of the analysis. For the last part of the comment discussing certain external systems like pigs and balls, the commenter is correct. It is not a "Continual" method as defined in the report. However, the authors feel that have stated the differences with the various methodologies. No changes have been made to the report in-line with this comment.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: Drawbacks of External LDS are summarized in Table 4.3 and page 35. We do believe that the real, main resistance is Technology Gap #1 - a lack of standardization/certification in this area. Also, in our opinion that pipeline operators want to operate, not engineer, their pipelines. No change has been made to the report.

Comment: "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. [Comment Submitted by API-AOPL]

Response from Contractors: In the opinion of the contractors, not always and we stand by this remark. As the report states, improved pressure sensors do help a great deal, but there are several installations where off-the-shelf sensors are used.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: The report does not comment upon why metering upgrades are being made, nor in fact did many of the interviewees know. The contractors do agree many other operators do install improved metering for LDS, which was the reason for the question during the interviews.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: Good point, but these remarks are already provided in the report.

Comment: "In reviewing the technical feasibility of LDS, the study describes reliability and robustness as key concerns, but provides no data or quantifiable operator experiences to allow an accurate assessment of LDS reliability. The section on quantifying performance contains no actual performance data. Academic formulas an engineering student might use to calculate performance are reproduced, but with no recent examples or experiences. In the technology benefits and drawbacks section (p. 4-33), internal LDS technologies were successively described as having "generally poor sensitivity, producing " false alarms," being "very insensitive, many missed leaks," and "not very sensitive," without any numerical description of performance rates, false alarm rates, maintenance costs or costs to fix or mitigate them. The study noted that only 3 external LDS are in active use, but admitted all are pilots or experimental and provided no data on their performance (4-42). It did not ask why or determine the degree to which performance and cost issues are a factor. We urge PHMSA to ensure that these technical issues are addressed before it makes any assessment of technical feasibility." [Comment Submitted by API-AOPL]

Response from Contractors: At all our industry interviews, the respondents were technical or technology management staff - they were not at a level involved with global budget allocation. This is made quite clear in the text. Therefore, we have no idea why LDS in general is considered low value. All types of LDS are being considered by the report**.** Also, the technical staff in general would like to implement and adopt new technologies - they simply are not provided the resources. No changes have been made to the report specific to this comment.

Comment: “Page 4-55 implies that fiber-based technologies do not need the cable installed close to the pipeline. A review of one of the PRCI reports referenced in this paper demonstrates that statement to be incorrect for temperature-based systems (that PRCI work did not evaluate distributed acoustic systems).” [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

Response from Contractor: Yes, the PRCI report disputes this, but in the opinion of the contractors, the PRCI tests never checked cable performance far from the pipe. Technical specs for this technology report that it can be installed offset from the pipe. The contractors have not changed this statement in the report.

Comment: “The draft report is seriously flawed with regard to assessing the ability of leak detection systems to detect ruptures and small leaks on natural gas distribution and transmission piping operated as part of distribution systems. The draft report substitutes unsupported opinions for facts on the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks on distribution piping. The draft report provides no data on the safety benefits and adverse consequences of requiring natural gas distribution operators to use leak detection systems. If released without major corrections, the report will be a disservice to the distribution industry and an embarrassment to PHMSA.” [Comment Submitted by APGA]

Response from Contractor: Specifics are missing from this rather sweeping statement which does not allow the contractors to address any particular issue. No change was made specific to this comment; although a number of other changes have been made to the report based on this commenter’s other comments as well as others, that may provide some clarification.

Comment: “Ignoring Leak/Rupture Detection Methodology for Natural Gas Transmission Pipelines

While the authors have clearly identified the varied sources of leak detection (thanks to the richness of the dataset in the incident report), they have chosen to ignore those other sources and have concentrated on SCADA and CPM based systems.

The Draft Report does not analyze the alternative processes for leak and rupture detection (e.g., operator personnel, public recognition; aerial and foot patrol) along with present and future technical improvements of those processes. This report confirms that leaks and ruptures were most likely to be reported by the public and then the emergency responders, followed by operator air or foot patrols and least likely by the control room CPM & SCADA. Figure 3.26 shows that equipment at 15% is least likely to report a leak while the various groupings of people are almost 80%. CPM = 15%, versus 1st party = 9%, 2nd party = 28%, 3rd party = 30%, perpetrator = 15%, other 7%.

This variety of detection sources and the synergy of these is a key focus of the INGAA IMM approach to improve the response time to an incident. A significant number of incidents utilize these other detection sources and in the gas transmission pipeline incidents are very important in rupture detection. A more sophisticated analysis by the authors of the variables involved in detection would clarify this value." [Comment Submitted by INGAA]

Response from Contractor: This comment appears to demonstrate a lack of clear thinking on the part of the commenters. The means by which leaks are detected per the operators' filings are fully described under Task 3. Other means by which leaks were detected are given equal weight in Task 3. In the opinion of the authors, the report clearly states that a pipeline's controller is monitoring and controlling the pipeline and its operation is the controller's responsibility. Other means of detecting leaks (other than by mechanical puncture) are from either deliberate surveys for leaks or more by chance if by the public and emergency responders. None of these latter methods of detection are full-time detection methods. INGAA may consider the public and emergency responders as detection sources but the report does not. Air or foot patrols or local operator personnel can be considered as part-time leak detection methods, the time window for which each of these detection methods are available for leak detection purposes varies. No change has been made to the report.

Comment: "Incomplete Analysis of Leak/Rupture Detection Technology Solutions

This report confirms the gas transmission industry's experience that CPM and SCADA aid in detection, but are remain insensitive or unreliable to be the essential solution to the detection of leaks and ruptures. The Pipeline Research Council International is continuing to conduct evaluations of leak detection systems and new information will be available in 2014.

The companion PHMSA draft research report on valves again confirms the limited public safety value of leak detection system for major ruptures on natural gas transmission pipelines.

Additional information and insight was available to the authors via the PHMSA public meeting and docket, but this information was not referenced in this report. The utilization of that information would have helped in the direction of the different sections.

The combination of these shortcomings threatens the viability of many of the conclusions of this report. Unfortunately, corrections of these flaws require a reassessment of the techniques used in this report, a reanalysis of the statistics and a redrafting of the conclusions." [Comment Submitted by INGAA]

Response from Contractor: The commenters do not make a clear statement or suggestion for changes on which a response can be given. No changes were made to the report.

Comment: "Incomplete Coverage of Leak/Rupture Detection Technology Solutions for Natural Gas Transmission Pipelines

This report confirms the gas transmission industry's experience that CPM and SCADA aid in detection, but are remain insensitive or unreliable to be the essential solution to the detection of leaks and ruptures. The Pipeline Research Council International is continuing to conduct evaluations of leak detection systems and new information will be available in 2014.

The companion PHMSA draft research report on valves again confirms the limited public safety value of leak/rupture detection system for major ruptures on natural gas transmission pipelines.

However, INGAA's IMM initiative focuses on improving the consistency of the response time of all rupture detection systems and coordination of subsequent mitigation efforts (i.e. public, operators and emergency responders)." [Comment Submitted by INGAA]

Response from Contractor: The commenters make a statement about new information available in 2014. It was not made clear what this information has to do with this current report in 2012. No changes made.

Comment: "Confusion in the Structure and Content of Document

The report, as structured, has comingled hazardous liquid pipeline, natural gas transmission and gas distribution discussions in one document is inappropriate and may cause confusion to readers. In some cases in this draft, the author has inadvertently utilized descriptions and jargon of one part of the industry for another part (e.g. pump vs. compress). It appears that the authors may not be intimately familiar with leak detection systems on natural gas transmission pipelines by the use of vocabulary and references used throughout the document." [Comment Submitted by INGAA]

Response from Contractor: The contractors believe Task 3 is clearly segmented into the 3 industry classifications. For the tasks associated with LDS technology and operational experience it is clear how the technology and experience may relate to those areas of interest to INGAA. The improper use of compressor versus pump was an obvious mistake made by the authors. With the exception of those changes, no other changes have been made to the report directly related to this comment. However, a variety of changes, mostly for clarification purposes, were made throughout the report with respect to Task 3 which may potentially assist with addressing this specific comment.

Comment: "Conclusion: While INGAA would have appreciated more time to examine and critique the Draft Report, we realize that the effort to address some of the major issues will be widespread and will require an extensive effort by the authors. We think it is expeditious that these issues be exposed quickly and that the paper be redrafted by the authors based on the reanalysis of these issues and be resubmitted to PHMSA and the public for review. Additionally, we strongly urge that in future study updates that the researchers acknowledge and use the full breadth of information available from the public and industry sources, and if there are questions on the accuracy of such information, then additional clarifications be requested." [Comment Submitted by INGAA]

Response from Contractors: The authors thank INGAA for their thoughtful and insightful comments on the draft report given the short timespan that INGAA had to digest the in-depth technical content and possibly the far reaching ramifications presented by the report**.** The contractors cannot address comments directed at PHMSA.

Comment: **"**In reviewing operational feasibility, the study notes operators should consider the reliability, availability and maintainability of LDS. However, it provides no detailed analysis of cases where LDS were deployed, or operator experiences with maintainability or reliability. For example, questions such as what maintenance was needed, how often, performed by whom, and with what level of training are not answered. Similarly, there was no data provided on reliability experiences in the field, false positives or failures. We urge PHMSA to ensure that these operational questions are answered before it makes any assessment of operational feasibility." [Comment Submitted by API-AOPL]

Response from Contractors: No, this analysis was not performed by the contractors. We did not do a detailed survey of individual operator procedures, nor do we suspect would we be allowed to for a public report. No changes were made to the report specific to this comment. The contractors also cannot address any recommendations to PHMSA.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: This is admittedly not explored in the report. However, the authors' opinion is that these costs, over a full-lifecycle, are typically exaggerated, and completely dwarfed by the other costs of an LDS. It is all about engineering a solution. If you cannot install a turbine flow meter for CPM in a remote HCA, then at least install a point External sensor package with solar panels.

Comment: "In addition to faulty theoretical scenarios, the study's examination of operator experiences is lacking. Study authors asked operators "purely technical issues" on budgeting cycles, cost-benefit approach and risk management processes (p. 6-20). They seem not to have asked, and did not collect, any actual data on experienced costs employing LDS, their installation costs, maintenance costs, or training costs. Nor did the study compare quoted purchase prices to actual eventual costs, maintenance costs over time, and replacement costs. The reader is left with a complete inability to determine the actual experienced costs of LDS. We urge PHMSA to ensure that these economic questions are answered before it makes any assessment of economic feasibility." [Comment Submitted by API-AOPL]

Response from Contractors: No, this analysis was not performed. We did not do a detailed survey of individual operator procedures, nor do we suspect would we be allowed to for a public report. Caveats are also included elsewhere with respect to cost benefit analysis in general, there are a variety of opinions on LDS, and suggesting operators need to perform an analysis more specific to their system. No changes were made to the report specific to this comment. The contractors also cannot address any recommendations to PHMSA.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: We stand by items 2 and 3. Gas CPM is feasible and is practiced. Also, we specifically state pressure monitoring just downstream of a pump facility is often ineffective. This is common sense, without flow measurements as well, the pressure controller will simply maintain pressure regardless of back-pressure.

Comment: Multiple comments related to datasets used, and operators interviewed

"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." [Comment Submitted by API-AOPL]

"Additional examples of poor data collection, methodology or analysis include basing industry views on the interviews of 9 liquid pipeline operators, 5 gas transmission operators and 5 gas distribution companies. There are approximately 350 liquid pipeline operators registered with PHMSA. Along with a very limited sample size the report does not present a structured interview methodology to support the data reportedly gathered from operators. This industry survey data is cited in the report to justify a number of conclusions and more extrapolated data points. There are a number of avenues available to gather statistically significant data on industry practice. The report makes a poor attempt at this goal. We would be glad to work with the authors to help identify and close data gaps." [Comment Submitted by API-AOPL]

"AGA believes the sample set of 5 distribution operators interviewed for the study is an unrepresentative fraction of the actual operator numbers in the industry (5 out of ~1500)" [Comment Submitted by AGA]

Response from Contractors: The contractors agree a larger dataset would have been better. However, in the contractors' opinion this was a representative dataset. The contractors also feel they have provided a fair amount of caveats throughout the document on the limitations of their analysis.

Comment: "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." [Comment Submitted by API-AOPL]

Response from Contractors: The authors considered this point. However, given the deadline for submission of the report, time did not allow the inclusion of a table summarizing the 11 hazardous liquid cases studies.

Comment: "While the study may be technically correct, the comparisons of the leak detection systems deployed for hazardous liquid, gas transmission and gas distribution are confusing, unwarranted, and of minimal technical value. The properties of the materials transported, and the operational conditions vary so greatly that there is little or no technical justification to compare the LDS of different pipeline sectors." [Comment submitted by AGA]

Response from Contractor: We disagree with this comment and stand by the observation that: (a) yes, gas CPM works in most cases in exactly the same way for liquids systems; (b) in fact, a number of gas pipeline operators do use it; (c) the obstacles to its widespread use are instrumentation, and engineering effort devoted to implementation.

Comment: "Nowhere is the term odorant and odorization used in the document. AGA has several publications on leak detection in the distribution industry and believes these specialized publications are of more value in assessing LDS in gas distribution than this study which compares distribution to hazardous liquids and gas transmission pipelines." [Comment Submitted by AGA]

Response from Contractor: As mentioned in another comment, the report primarily focused on gas systems that were on SCADA or had some form of sensors and telemetry that in the opinion of the authors provide a more complete remote instrumentation, measurement and control platform, if designed and implemented effectively. Other means of detecting leaks (other than by mechanical puncture) are from either deliberate surveys for leaks or more by chance if by the public and emergency responders. None of these latter methods of detection are full-time detection methods.

Comment: "In addition, the report fails to recognize that instrumented leakage surveys are conducted frequently over the pipelines by gas transmission and distribution operators as required by §192.706 and §192.723 respectively." [Comment Submitted by AGA]

> **Response from Contractor:** These code sections are in fact already pointed out in a number of locations in the report, including explicitly in the introduction, as well as the concepts more generally covered in areas such as page 4-25, Section 6 and elsewhere.

Comment: "AGA notes that the overwhelming majority of gas distribution operators do not have SCADA systems. Additionally, many of the distribution operators that have a SCADA system use it for information collection, not pipeline flow or pressure control." [Comment Submitted by AGA]

> **Response from Contractor:** In the opinion of the authors, this is true for medium/low-pressure systems, which is beyond the scope of this report. We observe on p. 4-47 that indeed on Intermediate Pressure systems "SCADA" is really a metering system for flow rate information.

Comment: "I would recommend staying away from hard cost numbers when comparing the technologies. Based on discussion during panel sessions at one of the two DOT forums this year, the costs are all over the map. Some people reading this report are going to take the numbers to be gospel, which they are not." [Comment Submitted by Shane Siebnaler, Southwest Research Institute]

> **Response from Contractor:** The contractors believe they have been clear in the report that cost figures are only order-of-magnitude, and a variety of opinions on numbers are out there. There has been no change specifically to the cost numbers provided in the report. However in line somewhat with this comment and others raising concern with the cost benefit analysis portion of the report, some language has been added (for instance on pages 6-7 and 6-9) to try to be more clear that any operator will need to perform a specific, targeted benefits analysis for their own pipeline using actual percentage figures and cost basis appropriate to their situation and operational targets.

Comment: "Can external leak detection systems that detect liquid hydrocarbon releases be used in areas where prior leaks have occurred and the soil may retain residual hydrocarbon contamination?" [Comment Submitted by Elizabeth Skalnek, MNOPS]

> **Response from contractor:** It depends on the sensor. However, only a liquid-sensing cable (that responds to getting wet with hydrocarbons) comes with a warning against this situation. In general, even with a fiber optic hydrocarbon sensor, the system is calibrated against the initial hydrocarbon concentration state of the environment when installed.

Comment: **"**Has any analysis been done to better define which LDS technology is best suited to which types of pipeline configuration and operating parameters? Where does statistical work best, where does RTTM work best for example? There is a lot of confusion in the market place when it comes to selecting the optimal performing solution that achieves the lowest risk for the operator for the optimal price for a particular pipeline and specific set of requirements. Often times the cheapest solution is not the most optimal and does not achieve the lowest risk that may have been expected. Unfortunately, this discovery is learned too late to do anything about it. Perhaps this is more of a commercial and contracting issue, but it does directly impact the overall objective of improving pipeline integrity." [Comment Submitted by Tony Collins, Telvent]

Response by contractor: The general answer is no, not that the team is aware of. However, the comment is generally reflected in the report on certain gaps in standards, measurable performance indicators, etc. in order to allow a rational cost-benefit analysis.