Pipeline Leak Detection—Program Management

API RECOMMENDED PRACTICE 1175
FIRST EDITION, DECEMBER 2015

AMERICAN PETROLEUM INSTITUTE

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0 Introduction

Background

The general public, Congress, the National Transportation Safety Board (NTSB), and the Pipeline and Hazardous Materials Safety Administration (PHMSA) have a high level of interest in the subject of pipeline leak detection. PHMSA has been exploring issues involving leak detection program (LDP) effectiveness for a number of years, including through proposed rulemaking. Recent Congressional mandates and National Transportation Safety Board (NTSB) recommendations are attempts to address gaps in LDPs. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 required the Secretary of Transportation to analyze technical, operational, and economic feasibility aspects on LDPs used by pipeline operators of hazardous liquid pipeline facilities and transportation-related flow lines. The Act also required a report to Congress and the issuance of rulemaking, if practical to do so. Along with this Recommended Practice (RP), PHMSA is working to address a leak detection related recommendation for natural gas transmission and distribution pipelines, as prompted by the NTSB. PHMSA has taken a number of initiatives to help address the congressional mandate and NTSB recommendation including sponsoring a public workshop on improving the effectiveness of LDPs in 2012, coordinating research and development forums and related solicitations in 2012 and 2014, and commissioning an independent study on leak detection in 2012.

PHMSA has communicated with industry on potential measures to further address leak detection effectiveness through related standards and asked the American Petroleum Institute (API) and the Association of Oil Pipelines (AOPL) for comment on whether expanding the existing API 1130, *Computational Pipeline Monitoring for Liquids,* or creating a new guidance document are viable options for addressing concerns of congressional mandates. In a joint response to PHMSA, API and AOPL chose the latter as the best approach to improve safety and made a commitment to develop this new RP for Pipeline LDP Management.

This pipeline LDP management Recommended Practice (RP) provides guidance to pipeline operators of hazardous liquid pipeline systems regarding a risk-based pipeline LDP management process.

This RP is specifically designed to provide pipeline operators with a description of industry practices in risk-based pipeline LDP management and to provide the framework to develop sound program management practices within a pipeline operator's individual companies. It is important that pipeline operators understand system vulnerabilities, risks, and program management best practices when reviewing a pipeline LDP management process either for a new program or for possible system improvements.

It is recognized that this RP creates new requirements and practices that may take time to fully implement.

Objectives

This RP is written to provide guidance to pipeline operators for developing and maintaining management of pipeline LDPs. The elements of this RP are written to conform to current pipeline regulations and to encourage pipeline operators to "go beyond" and, in so doing, to promote the advancement or stronger utilization of LDPs in hazardous liquid pipelines.

This RP is intended to be used in conjunction with other industry-specified documents.

This RP builds on and augments existing requirements and is not intended to duplicate requirements of any other consensus standards or regulations.

While API 1175 is based on industry best practices, each pipeline operator is expected to tailor their LDP to their particular requirements.

The goal of an operator is to operate their pipelines safely and reliably so that there are no adverse effects on the public, employees, the environment, or the pipeline assets. This pipeline LDP management RP aids in this primary goal by the following.

— Providing hazardous liquid pipeline operators with guidance on development, implementation, and management of a sustainable LDP to minimize the size and consequences of leak events.

— Providing pipeline operators with enhanced guidance on selection of leak detection systems (LDSs) using a risk-based approach and on establishing performance measures for the capabilities of LDSs unique to each pipeline to meet or exceed the requirements of 49 *CFR* Part 195, such as in 195.452(i)(3), pertaining to leak detection related preventive and mitigative measures a pipeline operator shall take to protect a sensitive area (SA).

— Addressing identified gaps and incorporating guidance into a comprehensive program document.

The LDP decisions rely on a thorough assessment and analysis of risk and threats as they apply to leak detection and should integrate with the pipeline operator's acceptable risk level. An LDP may reduce the consequence of a leak and contribute to the development from a "thinking to knowing" leak detection culture.

The sections of this RP do not include the following:

— detailed technical design of LDSs (as this is pipeline operator, LDSs, and infrastructure dependent);

— SCADA system design (as this is already covered in other API documents, for example API 1113, API 1164, API 1165, or API 1167);

— specific performance metrics (an individual pipeline operator's risk-based approach and engineering evaluation covers this);

— field response (as this is covered in a pipeline operator's emergency response plan);

— presentation of information to Pipeline Controllers (covered in API 1165);

— equipment selection criteria (as these are specific to a pipeline operator, LDS, and vendor selection);

— a universal metric for pipeline leak detection performance (it is not a practical objective); or

— a definition of the relationship between emergency flow restriction devices (EFRDs) and leak detection (EFRDs and leak detection are two different mitigation systems).

Pipeline Leak Detection—Program Management

1 Scope

API Recommended Practice (RP) 1175 establishes a framework for Leak Detection Program (LDP) management for hazardous liquid pipelines that are jurisdictional to the U.S. Department of Transportation (specifically, 49 *CFR* Part 195). This RP is an industry consensus document written by a representative group of hazardous liquid pipeline operators. API 1175 focuses on using a risk-based approach to each pipeline operator's LDP. Reviewing the main body of this document and following the guidance set forth assists in creating an inherently risk mitigating LDP management system. API 1175 represents industry best practices in managing an LDP. All forms of leak detection used by a pipeline operator should be managed in a coordinated manner. The overall goal of the LDP is to detect leaks quickly and with certainty, thus facilitating quicker shutdown and therefore minimizing negative consequences. This RP focuses on management of LDPs, not the design of leak detection systems (LDSs), and therefore contains relatively little technical detail. As with API 1130, API 1175 applies to single-phase pipelines only; however, the approach may be applicable to pipelines that are not single phase.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detection Sensitivity*

API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquids*, September 2007

API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators*, December 2010

API Recommended Practice 1160 *Managing System Integrity for Hazardous Liquid Pipelines*, September 2013

API Recommended Practice 1167, *Pipeline SCADA Alarm Management*, December 2010

US DOT [1] 49 *CFR* Part 195 (general) 2015

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1
continuous leak detection
Leak detection system that is operating in real time or near real time.

NOTE It is usually SCADA-connected or uses continuous telemetry.

3.1.2
consequence level
Ranking of the possible consequences of a leak based on a calculated value or a relative value of the consequences.

[1] US Department of Transportation, 1200 New Jersey Ave SE, Washington DC 20590, www.dot.gov.

3.1.3
dynamic leak volume
Amount of hazardous liquid that is leaked after the onset of a leak prior to the shutdown of the pipeline (or other appropriate operational response is initiated).

NOTE This is also known as pumped volume.

3.1.4
escalation barrier
Functional group of safeguards, such as primary containment processes, equipment, engineered systems, operational procedures, management system elements, or worker capabilities designed to prevent loss of containment (LOC) and other types of asset integrity or process safety events and mitigate any potential consequences of such events.

3.1.5
externally based leak detection systems
Applications that use sensors to directly detect the presence of a hydrocarbon or physical changes in environment due to a leak.

NOTE 1 These sensors are placed on or near the external surface of the pipe or, in the case of cameras for instance, within sensing range of the pipeline.

NOTE 2 These sensors may be called leak detectors.

3.1.6
groupthink
Psychological phenomenon that occurs within a group of people in which the desire for harmony or conformity in the group results in an irrational or dysfunctional decision-making outcome.

NOTE 1 Groupthink is often without critical evaluation of alternative viewpoints, actively suppresses dissenting viewpoints, and isolates the group from outside influences.

NOTE 2 Groupthink may be evident by loss of a sense of vulnerability, complacency, or an environment that supersedes the authority of the Pipeline Controller and does not allow for independent decisions to be made.

NOTE 3 NTSB has a number of publications related to this phenomenon under the topic Crew Resource Management.

3.1.7
independent means
That which may be a separate or complementary leak detection system that uses another technique, some verification method, separate calculations, leak detection specialists' involvement, or other procedure or process.

3.1.8
internally based leak detection systems
Applications that are internally based using field sensor data that monitor internal (and perhaps related external) pipeline parameters but are not actually detecting the presence of hydrocarbons.

NOTE Since these systems do not actually contact leaked hazardous liquid, internally based leak detection systems may be regarded as inferential systems (see API 1130).

3.1.9
leak detection

a) **leak detection method**
Classification of leak detection operation as being continuous or non-continuous.

b) **leak detection principle**
Classification of leak detection by categories that are externally based or internally based.

c) **Leak Detection Program (LDP)**
Top-level term that encompasses all the various LDSs (which may include multiple techniques) employed by the pipeline operator and identifies all methods used to detect leaks and the policies, processes, and the human element.

d) **leak detection technique**
Individual technology applications (e.g. real time transient model, wetted cable, fiber optical cable, etc.) used to actually detect or indicate a leak.

e) **Leak Detection System (LDS)**
End-to-end application of one technique that may be internally based or externally based and continuous or non-continuous.

f) **leak detection system (LDS) operational classifications**

1) **primary LDS**
LDS designated by the pipeline operator as being the main primary LDS.

2) **complementary LDS**
LDS that use a different technique, has different metrics, and, if possible, is independent of the inputs for the primary technique.

3) **alternative LDS**
LDS that is used when the primary and complementary are out of service.

4) **redundant LDS**
LDS that immediately takes over if the running LDS fails.

5) **backup LDS**
LDS that may be used to replace an LDS that has failed.

3.1.10
leak indication
Alarm or other notifying event that suggests that present conditions indicate the possibility of a leak.

NOTE 1 The possibility of a leak is stronger if there is more than one indication.

NOTE 2 Industry also uses the word “triggers” for leak indications.

3.1.11
leak monitoring
Form of pipeline leak detection that is intended to detect the occurrence of a leak smaller than a rupture.

3.1.12
leak verification
Analysis of pipeline operation and/or pipeline conditions triggered by the suspicion of the existence of a leak intended to provide sufficient confidence in order to make a formal determination of whether or not a leak exists.

NOTE It may involve onsite investigation.

3.1.13
loss of containment
LOC
Unplanned or uncontrolled release of hazardous liquid to the environment.

NOTE 1 In the industry, the words leak, spill, release, fluid release, or commodity release are sometimes used for a LOC.

NOTE 2 Sometimes this is called loss of primary containment or LOPC.

3.1.14
metrics
performance metrics
Performance category that is quantified by Key Performance Indicators (KPIs).

NOTE Leak detection metrics are well described in API 1130, Annex C and are grouped into four categories, or metrics, that determine a system's reliability, sensitivity, accuracy, and robustness.

3.1.15
mitigated consequence level
MCL
Consequence level of an event after the escalation barriers have been evaluated.

3.1.16
non-continuous monitoring
Type of leak detection that is periodic but not in real time.

3.1.17
overall leak volume
Total leak volume that occurs from the time the pipeline leak begins until all leakage is stopped.

NOTE It includes dynamic leak volume plus static leak volume.

3.1.18
PHMSA reportable significant incident
Significant Incidents are those including any of the following conditions, excluding Fire First incidents:

a) fatality or injury requiring inpatient hospitalization;

b) $50,000 or more in total costs, measured in 1984 U.S. dollars;

c) highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more;

d) liquid releases resulting in an unintentional fire or explosion.

3.1.19
risk tolerance
acceptable risk
Amount of risk that the pipeline operator is willing to assume.

NOTE When the level of risk is above an acceptable level or is not tolerable it exceeds the risk tolerance.

3.1.20
risk-based approach
Decision-making process that prioritizes the leak detection work based on the calculated risk, evaluates it against a level of risk tolerance, and then takes action to reduce the risk to a tolerable level.

3.1.21
rupture monitoring
Form of pipeline leak detection that is intended to swiftly detect the occurrence of a rupture.

NOTE 1 API/AOPL has produced a white paper called Liquid Pipeline Rupture Recognition and Response.

NOTE 2 What constitutes a rupture is determined on a pipeline by pipeline basis and defined by a pipeline operator.

3.1.22
sensitive area
SA
Specific locales and areas, not limited to HCAs or USAs, in or by the pipeline ROW where a leak may have significant adverse consequences to any or all nearby people, the environment, and community assets.

NOTE See 49 *CFR* Part 195 for definition and description of HCAs and USAs

3.1.23
static leak volume
Amount of hazardous liquid that is leaked after the shutdown of the pipeline (or other appropriate operational response if applicable) is initiated.

NOTE This is known as drain-down volume.

3.1.24
technology maturity
Characteristic of a technology that has been in use for long enough that most of its initial faults and inherent problems have been removed or reduced by further development.

NOTE One of the key indicators of a mature technology is the ease of use for both non-experts and professionals.

3.1.25
tuning
Process where the function of the leak detection technique is adjusted for more precise functioning.

NOTE Tuning is a way of increasing alarm confidence, decreasing time to detect (or leak volume) and/or adjust the leak detector configuration without adversely affecting the frequency of non-leak alarms.

3.1.26
unmitigated consequence level
Consequence level of an event without the effect of escalation barriers or preventative and mitigation measures.

3.2 Acronyms and Abbreviations

For the purpose of this standard, the following abbreviated terms apply.

CMMS	computerized maintenance management system
CPM	computational pipeline monitoring
CRM	control room management
DB	database
DfRM	Design for Reliability and Maintainability
DOT	Department of Transportation
FAQ	frequently asked question
FMEA	Failure Mode Effects Analysis
HCA	high-consequence area

IMP	integrity management program
KPI	key performance indicator
LDP	leak detection program
LDS	leak detection system
LOC	loss of containment
MMS	maintenance management system
MOC	management of change
OJT	on-the-job training
PHMSA	US DOT Pipeline and Hazardous Materials Safety Administration
PPTS	Pipeline Performance Tracking System
RACI	Responsible, Accountable, Consulted, Informed
RAM	Reliability, Availability, and Maintainability
RCM	Reliability-Centered Maintenance
ROW	Right of Way
RP	recommended practice
SA	sensitive area
SME	subject matter expert
USA	unusually sensitive area

4 Leak Detection Program

This document should be viewed as a listing of best practices to be employed when planning, selecting, designing, analyzing, implementing, maintaining, and empowering a culture within a Company's pipeline LDP management. While this document specifically addresses hazardous liquid pipelines regulated under *CFR* 49 Part 195, the philosophy may be applied to non-regulated pipelines as well.

In adopting the recommendations of API 1175, operators should progressively implement changes and establish a timeline for the associated work.

Pipeline leak detection shall be managed by structuring the various elements of leak detection into a leak detection program (LDP). An LDP shall promote a strong leak detection culture, which is critical in managing the human component of an LDP. The technical component of an LDP shall be managed by application of a leak detection strategy. This document outlines the following components of an LDP:

— leak detection culture and strategy;

— selection of leak detection methods;

— performance targets, metrics, and KPIs;

— testing;

— Control Center procedures for recognition and response;

— alarm management;

— roles and responsibilities and training;

— reliability centered maintenance for leak detection equipment;

— overall performance evaluation of the LDP;

— management of change;

— improvement process(es).

Figure 1 provides a flow chart outline of the LDP management process. It shows all the aspects of LDP management that are outlined in API 1175 and the relationship of the various aspects. This figure represents the process for most pipeline operators, but it is not intended that the aspects shown are followed explicitly.

5 Leak Detection Culture and Strategy

5.1 Leak Detection Culture

5.1.1 Culture Description

Culture is the behavior of humans within an organization and the meaning that people attach to those behaviors. Culture is a shared group attribute that comes about through the interaction of the individuals as the organization develops and agrees on a mutual set of values, morals, and decision making processes. Culture includes the organization's vision, values, habits, norms, systems, symbols, language, assumptions, and beliefs. It is an evolving attribute influenced by both internal and external factors. Some aspects of culture may be taught (i.e. roles and responsibilities), but the main part of culture is learned from other's actions and behavioral awareness. Doing every task the right way every time is a cultural discipline institutionalized through tenets of operation.

Just as pipeline operators have developed a strong safety culture, it is important for pipeline operators to develop a strong leak detection culture. An LDP includes not only the technology, but the people involved in applying the technology. Improving an organization's culture moves its people from thinking about safety and integrity to practicing safety and integrity.

Leak detection culture is visible by the level of commitment of all employees, particularly an organization's management. Culture is defined and enhanced by ongoing management direction and support.

Leak detection is an integrating discipline that relies on major functions of an organization working together to be successful. A strong leak detection culture that promotes prompt action has the potential to reduce the consequences of a leak.

5.1.2 Culture Indicators

The following behaviors are indicative of a strong leak detection culture.

— Visible ongoing management support for the LDP.

— A comprehensive leak detection strategy that is understood by all employees.

— Visible support for the LDP at all levels and sections of the organization.

— A goal to exceed the minimum leak detection requirements that are denoted by the regulations (see Figure 2).

— Ongoing support towards improving pipeline leak detection, even if the pipeline operator is meeting current leak detection goals.

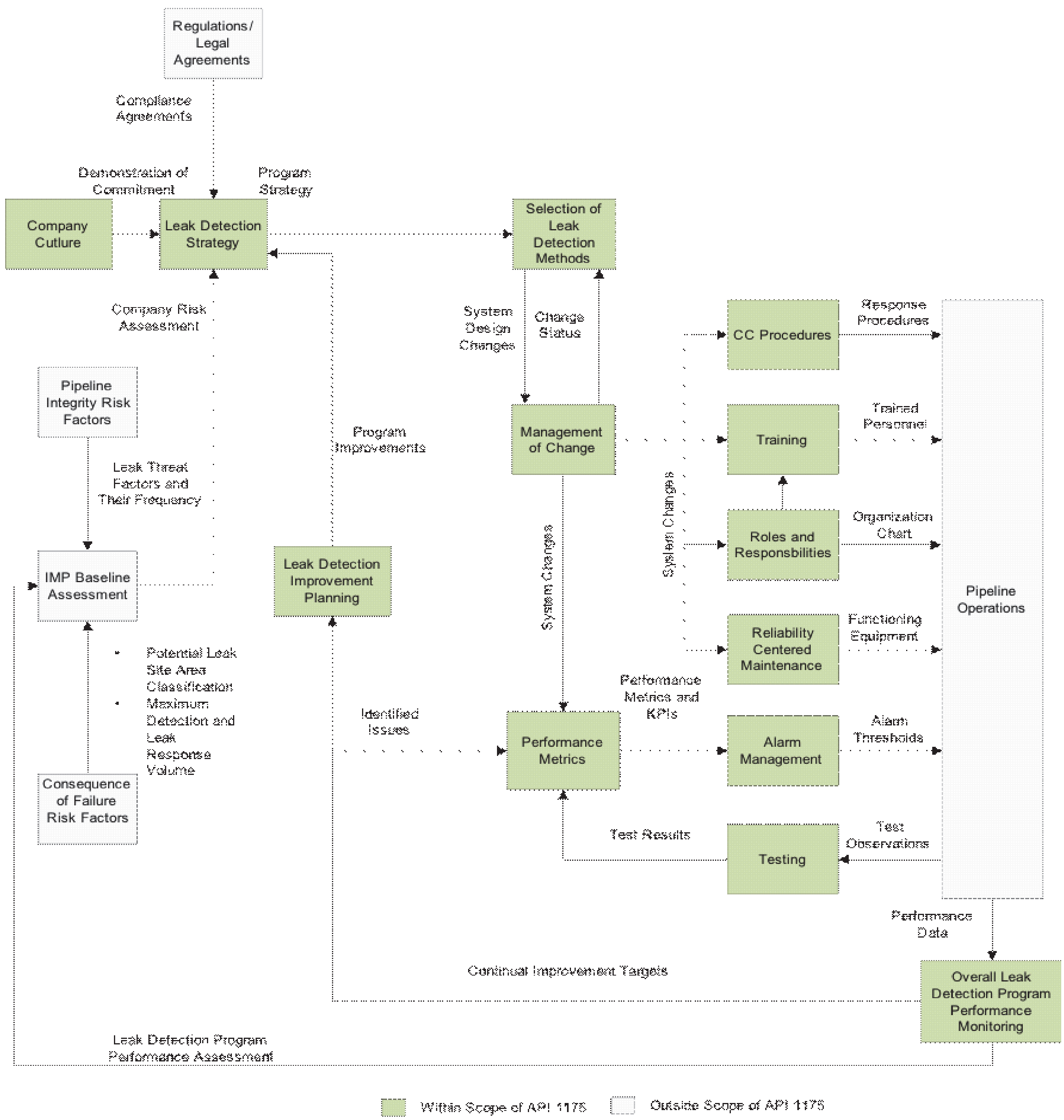

Figure 1—Leak Detection Program Flow Diagram

— Specific evaluation of all methods of leak detection.

— Promotion and endorsement of teamwork within departments and across the organization.

— Coordination and collaboration between the different entities involved in the LDP.

— Well-developed internal communications strategies between groups who work in different areas (i.e. field staff and Control Center staff) with different reporting structures.

— Clearly defined roles and responsibilities.

— Clear and concise policies, procedures, and processes in the Control Center and in other operations and maintenance activities.

— Comprehensive management of change process.

— Ongoing training of all staff regarding how each person supports leak detection.

— A focus on the safe and reliable operations of the pipeline with no negative repercussions on the staff who take actions in response to leak indications. This includes:

  — Stop-Work-Authority (SWA) or Stop-Work-Responsibility (SWR). Every employee has the authority and responsibility to stop unsafe work;

  — Shutdown when there is a leak indication. When in doubt, shut down and then assess; and

  — Empowerment of the primary user, the Pipeline Controller, who has individual authority to promptly take action such as exercising SWA during leak indication events.

Culture should be evaluated on an ongoing basis. Employee surveys and feedback or other observational techniques may be used to monitor and evaluate the culture. A record of the observations and recommendations should be made to support enhancing the culture.

5.2 Leak Detection Strategy

5.2.1 Strategy Outline

The pipeline operator shall develop and implement a leak detection strategy that covers all aspects of the LDP. The strategy shall set the requirements and outline the goals of the LDP and outline how the LDP will meet those goals.

A strategy describes how the ends (goals) will be achieved by the means (resources). The senior leadership of an organization is generally tasked with determining strategy. Strategy may be intended or may emerge as a pattern of activity as the organization adapts to its environment or competes with it. It involves activities such as strategic planning and strategic thinking.

The strategy should outline how the pipeline operator meets the pipeline's specified minimum regulatory requirements (see 6.3.1) and may "go beyond" Going beyond may be any of:

— adopting industry best practices,

— improving/enhancing existing LDSs,

— studying existing LDSs to determine how they may be improved,

— research and development activities,

— developing an LDP/LDS above minimum requirements,

— implementation of enhanced ROW surveillance,

— the use of more complex LDSs such as CPM,

— implementing complementary LDSs,

— enhancements in the Control Center, and/or

— enhanced maintenance and sustainability requirements.

The strategy shall be contained in a written document that is owned, retained and supported by management. The strategy may be written in many ways. The strategy documentation may be a single document or divided into multiple documents outlining the elements of the strategy. It may provide details for particular pipelines, types of products, classified areas, or include other aspects that require refinements of the overall strategy.

5.2.2 Elements of a Strategy

The elements, sections or topics that are essential to the strategy are outlined in the following list and then detailed below. This is not an all-inclusive list. A pipeline operator may determine other topics and include those in its strategy.

The topics are:

a) management commitment and leadership;

b) pipeline operator's requirements and goals;

c) how requirements and goals may be satisfied;

d) employing risk management;

e) selection of LDSs;

f) integration of all forms of LDSs employed;

g) regulatory requirements and industry standards;

h) ongoing measurement of performance of the LDP;

i) tuning and support requirements;

j) reporting;

k) training, testing, and operations/procedures;

l) review and approvals;

m) management of change;

n) ongoing improvement to the LDP.

5.2.3 Details of the Essential Elements of the Strategy

Expanding on the strategy elements:

a) Management commitment and leadership. A written strategy document should clearly show management is engaged and has a commitment to a comprehensive LDP. The leak detection strategy document should cover roles and responsibilities of all employees and stakeholders who are involved with the pipeline operator's LDP. Management should demonstrate its commitment through resources allocation, visibility, and leadership as outlined in the strategy. For the LDP, management should promote engagement and leadership at all levels of the organization. There should be a commitment to creating a culture that moves from "thinking leak mitigation" to "knowing what is in their leak mitigation strategy." Management should review and endorse an annual report on the LDP.

b) Pipeline operator's requirements and goals. Overall or broad goals for the LDP should be established and endorsed by management. The strategy may set more specific targets for Level 1 through 4 events (see definitions and Section 13 of API 1175 for details on levels). More detailed goals may be set at various operational levels of the pipeline operator. The pipeline operator should require that dependent and interrelated functions within the organization are sharing information and working as a team to achieve the goals. The pipeline operator should ensure there is a clear connection between goals and day-to-day work activities. Management may set targets for performance aspects of the LDP. The strategy may set limits for non-leak alarms so the confidence in the LDS is not eroded by too many alarms. The strategy may specify a worst-case leak from a corporate point of view that may not be a rupture or large leak volume, or a target may specify an improvement in the leak detection performance metrics (for examples: an annual reduction in detection alarm thresholds by x % or improvement in localization, accuracy, and/or time to detect). The strategy may note what the pipeline operator wants to achieve in the future.

c) How requirements and goals may be satisfied. The selection of LDSs chosen for the LDP shall cover all regulatory requirements and should cover pipeline operator requirements and goals. The LDSs should be implemented and maintained so the users have confidence in leak alarms. The strategy should emphasize the adherence to approved procedures and processes at all times. The pipeline operator should utilize the overall operating experience of their pipelines, and of their individual pipelines to maximize the capability of the LDP. In some cases, the strategy may outline particular types of equipment that may be used with the LDSs (e.g. types of meters). The LDP strategy should include continued awareness of developing technologies and the output of industry led initiatives to validate new technologies and approaches.

d) Employing risk management. The framework of the LDP shall be based on a detailed risk assessment. The assessment should cover the leak detection required performance and reduction in risk level provided by an LDP. The LDP may work with the integrity management program (IMP) to ensure factors specifically related to leak detection are in the risk assessments for each pipeline. All aspects of the LDP (e.g. selection of LDSs) may be dependent on the acceptable risk that the pipeline operator is willing to assume. Risk assessment may be used to change the level of application of the LDSs based on short term increased risks. A primary criterion within a pipeline operator's risk management program is LDP performance. Also to be evaluated are mitigating factors such as the operational response and emergency response in the event of a leak along the pipeline.

e) Selection of LDSs. The leak detection strategy document should cover all aspects of pipeline operations that affect the LDSs and the principles, methods, and techniques that are or will be used. The selection may focus on proven and industry common LDSs. Some aspects of leak detection are prescribed in regulations (i.e. visual surveillance and landowner awareness); however, the detailed application of these LDSs should be determined by each pipeline operator. The leak detection strategy document should address leak detection requirements during design of new or changes to existing pipelines. The selection should outline why particular LDSs are chosen. The pipeline operator may implement multiple LDSs that complement one another. The focus of selection should be on methods that provide continuous leak detection. Selection should cover issues such as increased risk in some areas, utilizing industry best practices, employing LDSs that may be tested and may have well defined KPIs or because no other LDS is possible. Selection should establish performance expectations that may be used for benchmarks for ongoing testing.

f) Integration of all forms of leak detection employed. Whenever possible, the outputs of all LDSs that are employed should be integrated. This suggests that all LDSs should be coordinated so they all support the goal of detecting leaks on the pipeline.

g) Regulatory requirements and industry standards. The strategy should list or refer to a list of all regulatory references and any industry standards that apply to the LDP. In 6.3 and throughout the document, the 49 *CFR* Part 195 requirements (i.e. 195.452 (i)(3) and (i)(4)) various PHMSA guidance notes (FAQ 9.4) and industry standards are noted. These may serve as a primary list. The strategy document should outline how these regulatory and industry standards are applied and perhaps which parts do not apply and why.

h) Ongoing measurement of performance of the LDP. The individual LDSs shall be tested or evaluated on a periodic basis or when there is a need to do so. The strategy should state that the overall LDP performance shall be evaluated annually, not to exceed 18 months. The overall evaluation may include comparison to performance achieved by other pipeline operators. The LDS document should emphasize the importance of having methods to measure performance (sensitivity, reliability, accuracy, robustness) using measurable KPIs. The health of the leak detection culture should be assessed or tested. The evaluation may be by comparison to industry best practices.

i) Reporting. The strategy should outline the reporting to both internal and external entities (for example, to industry databases). Reports to levels of management may be on a periodic basis but there should be an annual report on the LDP to management, not to exceed 18 months. Recommended changes based on these reports should be passed to an improvement process. The strategy may note the operator's commitment to contributing LDP information to the API's PPTS database.

j) Training, testing, and operations/procedures. The strategy should make a commitment to rigorous training of employees and appropriate level of training for other stakeholders. A training program should be developed to not only train employees and stakeholder in the technical aspects of their work, but also their roles and responsibilities as a part of the leak detection team. The strategy should outline a requirement for testing of the LDSs or evaluation of LDSs to ensure that design performance is maintained. The strategy shall outline the requirements for procedures and the application of procedures during operation.

k) Review and approvals. The pipeline operator should periodically review their LDS document to ensure it is up-to-date. The LDS should be modified as needed and reaffirmed with management of the pipeline operator.

l) Management of change. The strategy shall outline the requirements for management of change because operation of the LDP involves many functional areas of pipeline operation. Subtle operational or equipment changes may have an adverse direct impact on leak detection unless they are tightly controlled and managed.

m) Ongoing improvement of the LDP. Continual improvement requirements in the LDP should be outlined in the strategy. The LDS should indicate the importance of and support for an improvement process to address gaps if the targets are not met and to accommodate changes to regulations, pipeline operations, assets, stakeholder expectations, and overall improvement of the LDP. The pipeline operator may indicate a goal of improvement by, for example, evaluating industry best practices and lessons learned. Improvements should help move toward training improvement and strengthening of the culture. The strategy may indicate the desire to evaluate new technologies and the output of industry led initiatives to validate new technologies or be involved in leak detection R&D to improve the leak detection capabilities.

6 Selection of Leak Detection Methods

6.1 Selection Process Overview

LDSs are implemented to provide early notification of loss of containment (LOC), so immediate and subsequent actions may be taken to mitigate the consequence of the leak. The LDS decreases the dynamic leak volume by decreasing the time required to detect a leak and initiate a shutdown, which then allows action to be taken to manage the static leak volume.

The intent of this section is to help pipeline operators select which LDSs and associated leak detection principles, methods, and techniques to include in their LDP. This selection process may be used for the selection of new applications, to add additional LDSs, or to re-examine existing LDSs.

The selection of LDSs, leak detection principles, methods, and techniques is a multifaceted, multi-step, iterative process that involves at least the following elements:

— performing an overall risk assessment, usually through a leak detection-focused risk assessment;

— incorporating regulatory requirements, utilizing industry RPs (as warranted), and integrating the pipeline operator's requirements;

— linking the pipeline operator's performance metrics, KPIs, and targets;

— evaluating the best available technology for leak detection for the operator's pipelines;

— designing the LDP through selection of the LDSs and associated principles, methods, techniques that become the pipeline operator's LDP, including primary, complementary, and perhaps alternative LDSs;

— aligning the selection with the pipeline operator's leak detection culture and strategy;

— modifying the selection to cover particular requirements of individual pipelines;

— evaluating the leak detection capability to ensure that the LDP covers all elements above;

— ensuring that the LDP has no gaps in certain, but infrequently occurring operating modes.

If an LDP is already in place, this selection process may be applied to validate the selection and to ensure the existing program meets these best practices outlined and the requirements within.

In any case, each facet or step of the selection process should be documented.

6.2 Risk Assessment

6.2.1 Risk Assessment Factors

Risk assessment is a critical part of the LDS selection procedure. The risk may be compared against the pipeline operator's risk tolerance (see 6.2.2).

Leak detection reduces the consequence portion of an LOC but does not reduce the likelihood of a leak. However, an appreciation and evaluation of leak event likelihood (or probability), threats, vulnerabilities, and frequency of leaks drives the selection of LDSs and the design of the LDP.

The risk assessment should attempt to estimate the unmitigated and mitigated consequence level of different leak rates at each location of the pipeline and assess the likelihood of each leak rate occurring by evaluating the possibility of the occurrence of the various threats.

The primary possible causes or threats of a pipeline failure that results in a leak are outlined in Annex A. Different initiating events have different likelihoods to form different size leaks. The pipeline operator's historical information or industry historical information are the best source for estimating the possible size of leaks, the volume released, or the different release scenarios. It is important to recognize that the worst-case leak may not come from the highest possible leak rate or potential leak volume. Also, some leak detection technologies depend on how the leak is formed. It is therefore recommended to estimate the likelihood for a representative sample of possible leak rates during the risk analysis. It is important to understand that typically, LDSs become less reliable at lower leak rates or require more time to detect as a leak rate decreases

Usually, an IMP risk analysis is available to make the work of leak detection capability evaluation, a specific risk analysis, easier. However, the operator may review the IMP analysis to make sure weight is put on relevant factors that are important to the selection of the leak detection principles, methods, and techniques. In general, IMP risk analysis looks at likelihood and consequences (unmitigated) equally, but the leak detection risk analysis looks more at consequences (both unmitigated and mitigated) than likelihood.

A comprehensive risk analysis and evaluation should evaluate the existing operational LDP elements as they relate to mitigating the consequences of a leak. Integrity management activities should be evaluated along with the pipeline segment's characteristics to determine the likelihood and consequence of a failure occurring. The risks associated with LOC differ for various pipelines, hazardous liquids being transported, and the location of a particular pipeline. A specific risk analysis and evaluation may be performed for LDSs on each individual pipeline system or segment; typically called a leak detection capability evaluation [as per 195.452(i)(3)].

There are other factors that have a significant impact on the LOC risk such as the location of the leak, what type of material is being leaked, the ability of operations to isolate and restrict flow, the quality of the LOC response program, and the effectiveness of the leak prevention/IMP. Leaks at different locations or with different materials may have significantly different consequences.

Also, 49 *CFR* Part 195.452 (i)(3) advocates a risk-based approach to the evaluation of a pipeline operator's LDP and lists factors fundamental to the selection process. Since the risk-based approach should evaluate overall risk, consequences, and likelihoods, the operator may look at all three of these items during the selection process.

In short, the risk factors in the LDS selection (see Annex A for expanded risk assessment evaluation points) are as follows.

— Overall risk analysis of the pipeline.

— Review of the IMP, particularly the risk assessment results.

— Review of the existing pipeline infrastructure (age of pipe, history of pipe, operating pressure-to-hydro test ratio (i.e. the safety margin), diameter, length, size, type of hazardous liquid carried, pipeline profile, high-risk areas, consequence areas, threats along the pipeline, ignition sources, specific terrain between the pipeline and the high-consequence area, etc.).

— Review of known leak scenarios, history of leaks and their causes, an estimate of the likelihood of each scenario occurring, and, if possible, anticipate additional leak scenarios.

— Isolation capability (pumps, number of valves, and the types and their locations). Note that the current regulations already require a risk assessment as part of the normal pipeline integrity management process that incorporates evaluation of valve operations with leak detection performance.

— Emergency response/leak response capability, including nearest locations of response personnel and time to respond.

— Leak detection capability of the existing LDSs:

  — performance metrics: reliability, sensitivity, robustness, and accuracy;

  — KPIs and evaluations of the LDSs;

  — primary, complementary, alternative LDSs in place and their coverage.

— Leak detection capability of the existing LDP:

  — strength of the leak detection culture;

  — strength and completeness of the strategy.

— Leak size reduction initiatives and any IMP risk reduction initiatives:

  — geopolitical or environmental factors.

6.2.2 Risk Tolerance

Figure 2 shows how an overall risk score for various pipelines or pipe segments may influence the selection of LDSs within pipeline operator's leak detection strategy. Each vertical bar represents the cumulative risk score for a pipeline or pipeline segments.

A high-risk score equates to a higher consequence and/or higher likelihood of failure. This implies that pipelines that have a high-risk score should have a leak detection strategy that goes above and beyond the Part 195 minimum regulatory requirements. Typically, the Part 195 minimum regulatory means to detect leaks are surveillance patrols 26 times per year not to exceed a three-week interval, an in-line inspection program to detect pipeline issues through pressure testing, hydro-testing, and/or smart-pigging and public awareness programs.

The horizontal lines represent the pipeline operator's decision on what type of leak detection strategy is appropriate at a given risk level. The LDP that meets pipeline operator requirements that are outlined in the pipeline operator's strategy are shown above the level of the Part 195 (i.e. 49 *CFR* Part 195) Prescribed and Minimum Required Leak Detection line in the figure. For example, the horizontal lines exceed the risk level, and the leak detection strategy represents a tolerable risk.

If a pipeline's risk exceeds the level of the highest horizontal line (presumably the best leak detection available in the pipeline operator's LDP), then changes may be made to the pipeline's operation, its physical characteristics, or the leak detection strategy. Examples of the types of changes might be: changing the hydraulics; changing the MOP; segmenting the line with additional integrity meters; or the addition of a more appropriate leak detection method in the LDP. In some cases, the operator may specify the acceptable length of time to operate above the highest horizontal line.

Neither the minimum leak detection nor enhanced leak detection is implemented without cost. Industry best practices leak detection is costly. Selection of leak detection strategy for each pipeline or pipeline segment should take into account the practicality of implementing the strategy in relation to the risk mitigation benefit.

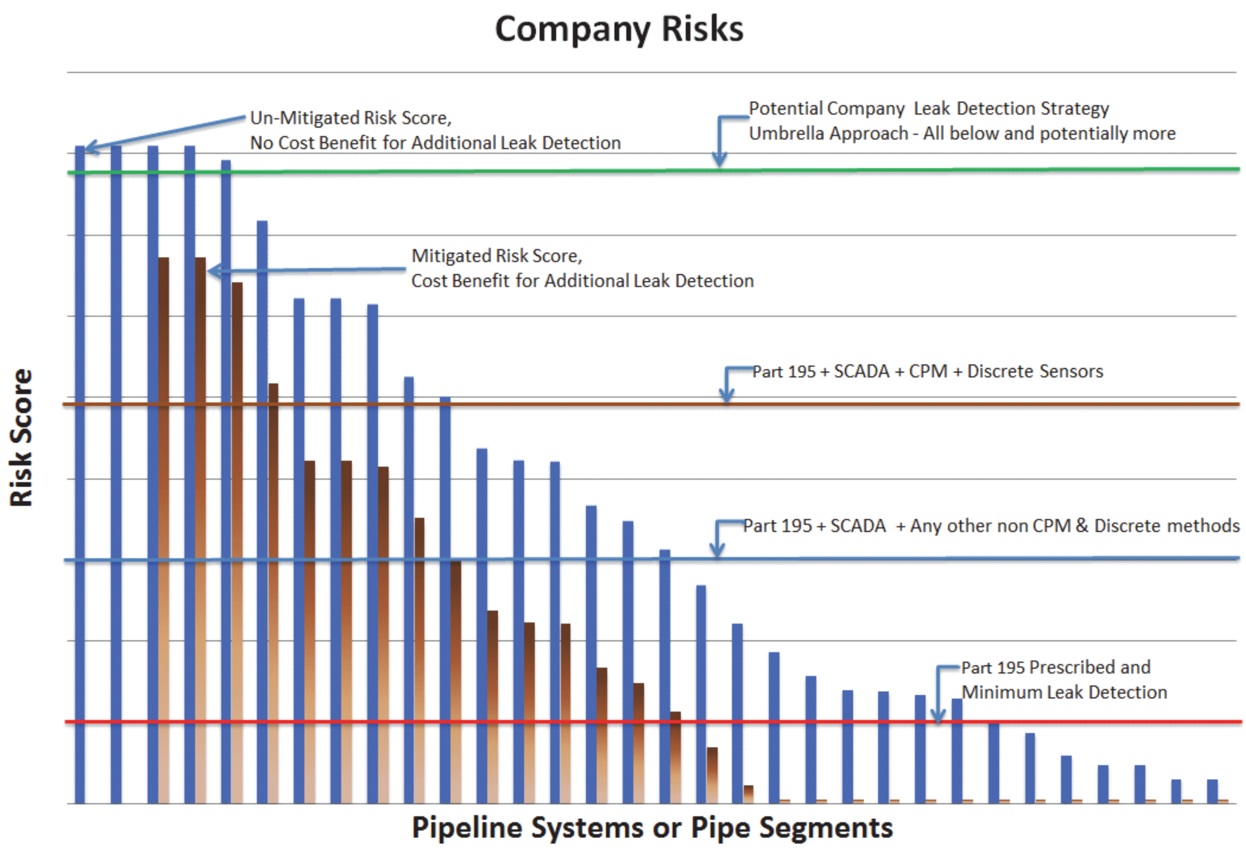

Figure 2—Mitigating Risk with Leak Detection

6.3 Incorporating Regulatory Requirements and RPs

6.3.1 Regulatory Requirements

The primary regulatory requirements for liquids pipelines are outlined in 49 *CFR* Part 195. An operator shall know all the leak detection and related requirements of 49 *CFR* Part 195 and any other regulatory requirements that apply to its pipelines.

The minimum leak detection is prescribed by regulations in 49 *CFR* Part 195 and it includes landowner awareness (third-party reporting) and periodic right-of-way inspection. In some cases, requirements may include smart pigging, pressure testing, requirements in special conditions, or initial construction approval. In Figure 2, these are referred to as Part 195 prescribed and minimum required leak detection.

Third-party reporting, a part of the landowner awareness required by Part 195, is a type of LDS. Public awareness and coordination is a key aspect to implementing this type of LDS in any area. 49 *CFR* Part 195 outlines specific minimum requirements in 195.440 that also incorporate recommendations from API 1162. In an unpopulated area, although the risk to people is reduced, it is not as effective to depend on third-party reporting leak detection methods. However, when a third party is present along the pipeline ROW, it is important that they know what to look for and know who to call, which is a training aspect.

The following code sections (with a brief description of contents) are applicable to liquid leak detection.

— Section 195.134, CPM Leak Detection, applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such pipelines, each new CPM LDS and each replaced component of an existing CPM LDS must comply with Section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM LDS.

- Section 195.402, Procedural Manual for Operations, Maintenance, and Emergencies, contains a number of requirements that are applicable to leak detection and response such as:

  - 195.402 (c)(2) requires procedures for gathering of data needed for reporting accidents;

  - 195.402(c)(9) requires procedures for detecting abnormal operating conditions by monitoring pressure, temperature, flow, or other appropriate operational data and transmitting these data to an attended location for facilities that control receipt or delivery of hazardous liquid;

  - 195.402(e)(2) requires procedures for prompt and effective response to emergencies such as accidental leak of a hazardous liquid;

  - 195.402(e)(4) requires procedures for taking action such as emergency shutdown to minimize volume leaked.

- Section 195.412, Inspection of Rights-of-Way and Crossings under Navigable Waters, requires pipeline operators to inspect surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying, or other appropriate means of traversing the right-of-way. Pipeline operators are required to inspect each crossing under a navigable waterway to determine the condition of the crossing.

- Section 195.444, CPM Leak Detection, requires each CPM LDS installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) to comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher (i.e. Pipeline Controller) training on the LDS.

- Section 195.446, CRM has inherent requirements that help improve leak detection response for pipeline operators subject to the CRM regulations.

- Section 195.452, Pipeline Integrity Management in High Consequence Areas, requires pipeline operators to have a capability to detect leaks in these high-consequence areas and to perform modifications to assure and improve this capability. Leak detection is included as one of the measures pipeline operators should take to mitigate the consequences of a LOC and to protect SAs along their pipeline.

  - 49 *CFR* 195.452(i)(3) states a pipeline operator shall, at least, evaluate the following factors: length and size of the pipeline, type of hazardous liquid transported, the pipeline's proximity to the high-consequence area, the swiftness of leak detection, location of nearest response personnel; leak history, and risk analysis results. Some of these factors overlap into other selection facets or criterion.

Additional details for hazardous liquid pipelines are:

- there may be special conditions or recommendations,

- in some cases, there may be a specific requirement for a specific LDS based on a contractual requirement where the pipeline operator operates a non-owned pipeline.

6.3.2 Recommended Practices, Standards, and Publications

There are a number of related RPs, standards, and publications. These are noted in Section 2, Normative References. Sources of additional information that may be useful are listed in the Bibliography.

6.4 Leak Detection Strategy Requirements

The leak detection strategy may be satisfied in part by selection of leak detection systems (LDSs) that best fit the requirements of the strategy. The strategy may for example set a number of goals and targets. These should be understood and accommodated during the process of selecting LDSs. For example, the strategy may require primary and complementary LDSs.

The leak detection design and selection aspects should be aligned with the pipeline operator's Level 1 through 4 KPIs (which are discussed in Section 13). The overall goal of a pipeline operator's leak detection strategy is to provide the resources required to positively identify an LOC from a hazardous liquid pipeline within a time period that is commensurate with the associated level of risk. These resources should encompass the technology, processes, and trained personnel to monitor the pipelines to ensure indications supporting a possible LOC are rapidly acknowledged and acted on.

To meet the requirements of the strategy, the operator may implement complementary and alternative LDSs as a part of the LDP. The main LDS may be called the primary LDS by the pipeline operator. However, the designation "primary LDS" is not simply defined. An LDS that is primary during operation may not be primary on a shut-in pipeline when another LDS may be more reliable. Most often, a continuous method is chosen as a primary. On many pipelines, a CPM technique is commonly the primary; however, an externally based LDS may satisfy the leak detection strategy.

A complementary LDS may be designated as such. It may be continuous. A complementary LDS should use a different technique, have different metrics, and if possible, be independent of the inputs for the primary technique. In some cases, depending on risk, more than one complementary LDS may be implemented throughout the pipeline system or just in specific segments if it is not practical to implement across the entire pipeline system.

An alternative LDS may be chosen that may be used if the primary LDS is out of service. Usually, an alternative LDS is used under closely supervised leak detection monitoring of the pipeline operation.

There may be other LDSs that are designated as redundant (i.e. have the same function as another LDS and exist so that LDP does not fail if the primary or complementary LDS fails). The redundant LDS may be running and mirroring the system to which it is redundant so fail-over is automatic; or there may be a backup LDS used to replace an LDS that fails. The backup may be made active when it is required.

Table 1 is a visual example of an LDP that shows leak size classifications, the LDS that may be used for leak detection, and an unspecific factor of time to detect LOC. Information on the definition of the various leak sizes is found in API 1130, Annex B.

Table 1—Visualization of an Example LDP

Leak Type	SCADA Monitoring	CPM	Public Awareness	Aerial Surveillance	In-line inspection
Rupture	✓	✓	✓	✓	N/A
Medium Leak	O	✓	✓	✓	✓
Small Leak	X	O	O	✓	✓
Seep	X	X	O	O	✓

Leak Rate ⇧

Time-to-Detect ⇨

Key

✓ Detection Probably O Detection Possible X Detection Improbable

6.5 List and Classification of LDSs

The LDSs that may be used to detect leaks cover a wide spectrum of techniques, principles, and methods. The techniques vary from surveillance to hydrocarbon sensors to real-time monitoring software. The principles employed may be externally or internally based. The methods may be continuous or non-continuous. Table 2 provides an example list of the leak detection techniques and categorizes them as to whether they are internally based or externally based and continuous or non-continuous. Table 2 is not intended to be a comprehensive list of leak detection techniques.

Each practical LDS has its strengths and weaknesses that are dependent on the characteristics of the LDS, the specific application, the leak detection technique, its technology maturity, and the complexity of the pipeline to which the LDS is applied. In combination with processes or procedures, applying the appropriately selected LDSs is the key to effective pipeline LDP.

It is important to note the following when investigating the various techniques for leak detection.

— Additional instrumentation may need to be added to the pipeline to support a particular technique.

— Additional maintenance, support, and testing may be required for some techniques.

— Some existing techniques may be enhanced. For example, the visual aspect of surveillance may be enhanced by the addition of infrared sensors.

It is important to note that not all the techniques listed in Table 2 are proven; some are still being evaluated for practicability in industry. Practical techniques are readily available, potentially pipeline operator deployed, and possess some form of adequate field-based installation.

Table 2—List and Classification of LDSs

	Externally Based		**Internally Based**	
	Physical Inspection	**Sensor-Based Monitoring**	**Manual Observations**	**Computational Pipeline Monitoring**
Non-Continuous	Aerial Surveillance	Ground-Penetrating Radar	Volume or Line Balance Calculations	
	Ground-Based Line Surveillance	Sniffer Tubes	Hydraulic Calculations	
	Hydro Testing	Tracer Chemicals	Pattern Recognition	
	Satellite	Intelligent Pigs	Shut-in Testing/Stand-up Testing	
	One Call System/ Public Awareness	Soil Sampling		
Continuous		Sensing Cables	Controller SCADA Monitoring	Conservation of Mass (real time)
		Cameras		Real-Time Line Balance
		Chemical Analyzers		Pressure Monitoring
		Acoustic Sensors		Pattern Recognition
		CP Monitoring		Digital Signal Analysis
				Statistical Analysis

During LDS evaluation, it may be helpful to discuss the application and expected performance with the vendor and/or other users of the specific LDS. Nevertheless, one should be mindful that each pipeline operation is unique, hence the actual performance of the same LDS applied to two different pipelines may vary significantly.

For additional information on types of techniques, refer to the PRCI and NETL reports cited in the Bibliography.

6.6 Evaluating and Selecting Suitable Technologies

After evaluation of risk, pipeline operator strategy, and regulatory requirements, the operator should develop a list of selection criteria and select LDSs. There are three key areas: what features are needed, what performance is required, and the process of the selection criteria to vet the LDS.

Selection factors for LDSs are outlined below, in API 1130 Section 4.2, and further in Annex B. The list in API 1130 applies to CPM LDSs, but many are applicable to other non-CPM techniques. There are usually a number of other LDSs used in the operation, for example, over/short calculations and SCADA monitoring (and trending), and there may be automated LDSs such as meter-to-meter balancing.

The leak detection techniques that meet regulatory requirements are somewhat prescribed by the regulations or committed to by, for example, special permits, corrective action orders, or safety orders.

When selecting the LDS that is to be employed in the LDP, the pipeline operator should be cognizant of any potential limitations inherent to the LDS that could impact its ability to rapidly and accurately detect leaks in the field. The performance should be quantified by use of metrics and related KPIs.

The pipeline operator may choose to further classify the LDS choice(s) as regulatory (Part 195) level LDSs, API 1175 best practices level (utilizing widely used LDSs), or API 1175 green-field level (using new technologies).

There are a number of factors related to physical environment and hazardous liquids transported that may affect the particular leak detection method(s) selected. These include elevation profile, waterways (rivers, lakes, streams, oceans, etc.), major thoroughfares, spans and bridges, fluid properties, limitations of the location, meteorology, radiant heat effects, etc.

The choice of an LDS is a long-term decision based on both capital expenditure and long term operational expenditure. The selection process should evaluate the entire life cycle impact on both. The selection may evaluate ancillary benefits that may be derived, such as the use of a fiber optic network for pipeline communications, public address and general alarm (PAGA) systems, closed-circuit television (CCTV), and private automatic branch exchange (PABX), as well as public benefits such as lease of spare lines to the telecoms industry to bring high speed internet to remote communities. The operator may evaluate the tangible as well as ancillary benefits because such issues may affect not just the life cycle calculation but also the likelihood of achieving approval.

When designing an LDP, it is recommended to maintain an overall system view and recognize that each component works with the others to provide the desired performance. Different components play different roles in mitigating the overall consequence. Table 1 shows an example of different categories of LDSs defined by their relative time frame.

The choice of an LDS(s) may be specified in the pipeline operator’s strategy for:

— the special case of non-regulated pipelines;

— pipelines that do not or cannot have all of the required instrumentation;

— pipelines that do not meet the common criteria for effective LDS, such as those operating with two-phase or multiphase flow;

— pipelines with a history of very small (seepage) leaks;

— pipelines with a history of ruptures;

— pipelines with unique operating histories that characterize significant operational challenges.

6.7 Modifying Selection for Particular Requirements of Individual Pipelines

At some point, the operator should ensure that the particular operational conditions of a pipeline or its design may be accommodated by a baseline LDS used on other lines. LDSs are engineered systems, meaning that the same LDS applied to multiple pipelines may have different results or the LDS may not perform as well on some pipelines. Perhaps an additional LDS or modification to the LDS may be needed to accommodate leak detection on other pipelines; or perhaps installation of additional instrumentation or changes to operation may be required.

6.8 Periodic Review of Selection

The operator may periodically evaluate the selection of LDSs to ensure they are meeting the requirements of the leak strategy. Possible reasons for the review may be: population or environmental changes that may have occurred around the pipeline, when technology or operating conditions warrant, or the periodic review may be performed on a timed cycle.

One potential approach to a timed cycle is to review the leak detection requirements based on a five-year cycle, similar to a baseline IMP. The review would look at the items outlined in 49 *CFR* Part 195.452 and use a team of leak detection and risk experts who would utilize a risk matrix or other ranking process. In particular, the team may look at SAs, leak detection alarms, and any other performance-related information. The purpose is to keep the LDP current with this information. The selection process outlined may then be re-applied to the new conditions.

Improvements or other changes to LDSs or the LDP may be triggered by new circumstances such as:

— program modified by field experience;

— application updates;

— availability of new LDSs or extensions, to be evaluated by selection criteria;

— technology review cycle;

— IMP evaluation review;

— re-evaluation of the leak detection methods based on an established cycle;

— new pipelines are built and require leak detection;

— pipeline service is changed or there are significant instrumentation or measurement changes;

— change of regulatory requirements;

— strategy change;

— a requirement for enhanced leak detection.

7 Performance Targets, Metrics, and KPIs

7.1 General

Hazardous liquid pipeline operators should establish performance targets for their LDSs and define and track KPIs to ensure the performance targets are met. Typically, these performance targets are set as part of the pipeline operator's leak detection strategy, and the leak detection selection process attempts to select and implement the LDSs that will meet these targets.

In this RP, the terms "metric" and "KPI" are closely related. The metrics (e.g. reliability) are quantified by the KPIs (e.g. number of non-leak alarms) of the metric. KPIs and their targets should be specific and measurable quantities designed and implemented to facilitate the attainment of desirable overarching goals (e.g. high reliability) of a pipeline operator's LDP. API 1130, Annex C defines these metrics as sensitivity, reliability, accuracy, and robustness. While API 1130 is specific to CPM leak detection, the metrics can be applied to any LDS (e.g. externally based LDSs). API 1130, Annex DC provides a more extensive description of these metrics and suggests some performance KPIs. These types of KPIs are quantified by the pipeline operator. The leak detection vendor may assist as well.

Performance targets and KPIs may exist at the LDP level for a specific LDS and for a specific instance of the LDS, i.e. its implementation on a particular pipeline. The pipeline operator's performance monitoring of an overall LDP is discussed in Section 13 of this RP and covers KPIs at the program level.

Determination of the leak detection KPIs and performance targets are predicated by the goals of the pipeline operator's leak detection strategy.

The KPIs and performance targets in turn influence the selection of LDSs, both in terms of which LDSs are available in the LDP and which LDS or LDP is applied to specific assets. The leak detection targets are refined by the LDP's continual improvement process and by performance monitoring. The leak detection metrics and associated KPIs are designed to verify the performance targets are being met and to provide diagnostic information if they are not. The KPIs should be analyzed statistically to deduce appropriate performance targets.

An option may be to use an independent third party to evaluate the LDS and management of KPIs.

7.2 Performance Metrics and Key Performance Indicators

7.2.1 Goal and Targets

Performance metrics and KPIs should be defined, computed, and tracked to establish that leak detection goals are being met. The corresponding performance targets are then refined and revised the as part of the continual improvement process. KPIs should be designed to allow the pipeline operator to gauge the degree to which the goals are being met. The availability of KPIs should be evaluated when deciding on the leak detection goals. Goals that are overly broad or subjective are difficult to measure effectively. On the other hand, goals that are too specific or prescriptive may be more challenging to refine and revise, depending on the complexity of the pipeline system and number of LDSs implemented. Such goals may limit a pipeline operator to a specific LDS vendor, etc., that may be difficult to upgrade or replace. Annex D provides an example of performance metrics and targets for a CPM LDS.

7.2.2 Design of KPIs

KPIs can be designed for direct assessment and for diagnostic use. A KPI designed for direct assessment tells the pipeline operator if the performance target is being achieved. For example, if the performance target is no more than X alarms per month (not due to an LDS test or actual leak), then a KPI that counts the number of such alarms that occur directly indicates whether the target is being met. A KPI that estimates the amount of column separation (aka slack line) in the pipeline and counts the number of times it exceeds a threshold may be used as a diagnostic to explain why excessive alarms are occurring.

Many LDSs exhibit significantly different performance depending on the operation of a pipeline. Internally based LDSs such as CPM, for instance, are known to perform differently depending on whether the pipeline is shut down, operating in a steady condition, in a transient operation, during column separation, or at different flowrates. It may be useful to track each KPI separately for each operating regime in order to provide the data to make informed decisions about the performance of the LDS.

One possible way to assess the LDP and/or form a design basis for a LDP is to estimate the average time required for the overall LDP (i.e. all the LDSs implemented) to detect a leak for a range of probable leak rates.

7.2.3 Examples of Metrics, KPIs, and Performance Targets

7.2.3.1 Examples Overview

It is the intent of this RP to be general, focused on LDP issues, and not specific to a particular LDS. The examples given in this section are intended to clarify the issues of metrics, KPIs, and performance targets, and provide the confirmation framework of a pipeline operator's leak detection performance and strategy. They are groups under the overarching metrics of the LDP but the list is not by any means exhaustive and is not meant to be prescriptive. Not all of the examples given would apply to all LDSs. Because actual leaks are rare, it is often feasible to track some of the following KPIs by validation testing.

7.2.3.2 Performance KPIs for Reliability

The following KPIs may be used to assess leak detection reliability.

— Number of non-leak alarms (aka, false positive indications) per unit time (alarms/month), this may be tracked from observed data in normal operations.

— Number of missed leaks (aka, false negative indications) or percentage of missed leak events. This KPI may be expected to vary substantially with pipeline operation and somewhat with the location of the leak on the pipeline.

— Number of hours that the LDS capability is degraded for example, due to component, electronics or software issues.

7.2.3.3 Performance KPIs for Sensitivity

The following KPIs may be used to assess leak detection sensitivity.

— Average leak threshold. This is tracked separately for each leak observation time interval or window to assess sensitivity. This is a useful proxy for sensitivity, but remember that due to the probabilistic nature of many LDSs, leaks greater than the threshold may not be detected, and leaks less than the threshold may be. This may be tracked from observed data in normal operations.

— Minimum detectable leak size. This is tracked separately for each leak observation time interval to assess sensitivity. It is theoretically possible that leak detection sensitivity metrics may be estimated by performing an uncertainty analysis of the algorithms used in the LDS.

— Overall leak volume on which the LDS alarmed.

7.2.3.4 Performance KPIs for Accuracy

The following KPIs may be used to assess leak detection accuracy.

— Leak Flow Rate (Size) accuracy.

  — Many CPM systems compute a flow imbalance continuously with the imbalance in the flows compensated by the change in line pack. Since the sources of uncertainty such as instrument errors and unknowns in the pipeline operation are independent of a leak this is a useful proxy for the leak flow rate accuracy that may be observed during normal operation. This type of operation may be estimated using the techniques of API 1149.

  — For both CPM and non-CPM systems leak flow rate accuracy may be observed during leak testing.

  — For CPM systems this KPI may be expected to vary substantially with pipeline operation and somewhat with the location of the leak on the pipeline. To completely characterize the performance of a CPM LDS requires observing (or estimating) leak size accuracy at multiple operational conditions.

  — For external system this metric will likely be more consistent for different operations and leak locations.

— Leak location accuracy.

  — Leak location accuracy may be observed for both CPM and non-CPM LDS's during leak testing.

  — While API 1149 does not address leak location accuracy estimation, the techniques described in it may be used to do so for CPM LDS's.

  — This KPI may be expected to vary substantially with pipeline operation and somewhat with the location of the leak on the pipeline if a CPM is used.

  — For external system this metric will likely be more consistent for different operations and leak locations.

— Leak volume accuracy. The same comments apply to leak volume accuracy as leak size accuracy, because the leak volume is just the accumulated leak flow rate. To estimate the leak volume accuracy from the leak flow rate accuracy, the operator should know, or assume, the characteristics of the leak flow rate error. If the leak flow rate error is purely a precision error, the leak volume error accumulates as the root sum squared. If the leak flow rate error is purely a bias error, the leak volume error accumulates as the sum of the leak flow rate error. Assuming a purely bias error provides the worst case estimate.

— Diagnostic KPI's

  — Many leak detection systems such as Real Time Transient Model (RTTM) compute estimates of variables for which there are measurements, such as flow rates and pressures. Large deviations between these measured and computed values indicate performance problems with the LDS. While these do not directly relate to one of the metrics, they provide a useful diagnostic KPI.

  — Many leak detection systems such as an RTTM auto tune themselves by adjusting parameters related to pipe friction and heat transfer. When these parameters deviate from plausible ranges, it indicates performance problems with the LDS. While these do not directly relate to one of the metrics, they provide a useful diagnostic KPI.

7.2.3.5 Performance KPIs for Robustness

Leak detection robustness is concerned with how an LDS performs when some of the requirements of the LDS, such as measurements, are not available. The KPIs, therefore, are the same as those listed above but are taken during a time when a specific deficiency exists in the LDS environment. Deficiencies may include:

— loss of measurements, for instance, due to meter failure;

— loss of communication;

— unusual operating condition, such as draining the pipeline for maintenance, pigging, or operation during a column separation;

— LDS behavior during transient operating conditions.

Robustness may be concerned with performance when the pipeline operation does not conform to the requirements of the LDS; for instance, during shutdown conditions or column separation line conditions, when the LDS is not intended to deal with these.

The combinations of failures that are possible for robustness are virtually limitless, so the first task is to select a representative set of conditions. A common circumstance is loss of measurements from a site that is communicated to the LDS via a data freshness indication. Since even a small set of robustness tests performed on an active LDS may involve intentionally degrading the LDS for a substantial time, it is recommended that this testing be done using estimation methods, such as API 1149 for CPM LDSs, and/or by setting up an off-line or test instance of the LDS that allows the production version to operate normally.

7.3 Performance Targets

7.3.1 Defining Performance Targets

Performance targets define the expectation of a pipeline operator for an LDS or the specific implementation of an LDS on a particular pipeline based on the risk tolerance. Performance targets for an LDS are used primarily when selecting which LDSs to have available in an LDP and for initial selection of candidate LDSs for a particular pipeline. Performance targets for a particular pipeline are appropriate for making final selection of an LDS for an asset and for evaluating continual improvement possibilities.

It is the intent of this RP to be general, focused on pipeline LDP management issues, and not specific to a particular LDS. To encourage some commonality between different LDSs, pipeline operators are encouraged to group their performance targets according to the performance metrics as previously discussed: sensitivity, reliability, robustness, and accuracy. It is possible that not all of these metrics are equally appropriate for every LDS.

A pipeline operator may assign these metrics different importance according to the LDS or the asset to which it is applied. For example, an LDS intended for rupture detection has different metrics than one intended to identify small leaks.

7.3.2 Selecting Performance Targets

Care should be taken in selecting performance targets. Tailor performance targets to the level at which they are being directed. The performance targets for an LDS may reflect:

— the targets of the pipeline operator's LDP strategy may be broadly stated (e.g. sensitivity of less than 20 %);

— the attributes of the LDS employed may be more focused but may be given as ranges (e.g. sensitivity of less than 5 % to 10 %);

— the details of the pipeline implementation may be specific (e.g. sensitivity of less than 5 %);

— reduction in risk as a target.

It may often be the case that an LDS may have multiple performance targets. This follows naturally from the aforementioned overarching metrics of reliability, sensitivity, accuracy, and robustness that have been previously discussed. Multiple performance targets may arise in the context of evaluating different operating modes. Using CPM as an example, the sensitivity target during shutdown, steady state, and transient operations may be different.

With multiple performance metrics there is the possibility that conflicts may arise when setting targets. For most leak detection methods there is an inherent conflict between the sensitivity and reliability. Where such conflicts are found to exist, priorities may be established to reconcile them.

7.3.3 Determination of Performance Targets

7.3.3.1 Determination Overview

Performance targets shall be determined using sound engineering expertise and judgment. Generic claims of performance by a vendor or other proponents of an LDS are not a substitute for systematic and engineering-based methods of establishing performance targets. Performance targets may be determined by estimation or observation of the LDS performance.

Performance estimation and observation are described in the following discussions. These techniques do not directly produce an appropriate value for a performance target. Rather they inform the pipeline operator on what may be reasonably expected from a LDS. For instance, an API 1149 analysis provides a theoretical best case performance of a CPM system on a pipeline operating in nearly steady conditions. A CPM in the real world that has to function in transient conditions may not be capable of achieving this level of performance. Observing the same system's performance gives a figure that may be met, but does not drive improvement. However, knowing these numbers may assist an operator make a rational decision of what is likely to be an attainable goal for the LDS.

7.3.3.2 Determination of Performance Targets by Estimation

Performance estimation uses detailed knowledge of the LDS and how the inputs to and the operational environment of the LDS affect the performance. API 1149 is an example of this approach as it is applied to CPM LDSs. API 1149 contains an extensive discussion of the sources of uncertainties and how they affect leak detection performance. This principle may be applied to externally based LDSs. Annex C provides an example of uncertainties of four factors and demonstrates how they impact leak detection capability over various calculation windows. A pipeline operator may find it beneficial to perform these types of calculations to gain a better understanding of the capabilities of their LDSs. The fundamental principle of the output of API 1149 the LDS's sensitivity over time may be leveraged for both CPM and non-CPM LDSs. Performance estimation is appropriate where detailed and specific knowledge of the asset, the LDS, and the operations are available. This applies to assets that are installed or that have a detailed design available so that the specifics of the implementation are known. It implies that the methodologies of the LDS are known in sufficient detail to apply techniques such as uncertainty analysis.

The advantages of estimation are:

— may be performed before an LDS is implemented;

— allows comparison of different LDSs for an asset;

— provides prediction of the effects of changes to the configuration or operation of the asset or of the LDS.

The disadvantages of estimation are:

— it is a theoretical exercise that is not perfectly accurate, and the accuracy of the estimation is generally not known;

— when comparing different LDSs, if the difference in accuracy of the estimations is of the same order as the difference in the estimated accuracy, it provides no basis for selection and may even be misleading;

— the configuration of the asset should be known in great detail, including items such as accuracy and precision of inputs that are difficult to obtain or assess;

— the physical principle of the technique used for the LDS should be known in detail however, this may not be available for proprietary technologies;

— derivation of the uncertainty relations for an LDS require a thorough understanding of the mathematics and statistics of uncertainty analysis.

7.3.3.3 Determination of Performance Targets by Observation

Performance observation uses analysis of historic performance of the LDS and/or testing that is designed to establish the performance of the LDS. Performance observation techniques are appropriate where detailed knowledge of the asset and its operation are known, and true performance is not known, so it should be determined for the existing asset and operation. Performance targets by observation may be challenging for externally based LDSs.

The advantages of observation are:

— it provides a definitive result for the performance;

— it accounts for as-built, real-world conditions.

The disadvantages of observation are:

— it does not identify factors limiting the performance;

— it does not provide predictive information on how changing the configuration or operation of the pipeline system may affect performance.

7.3.4 Additional Factors in Determination of Performance Targets

These two methods (estimation and observation) of determining performance targets are not exclusive. As an example, observation of the performance of a CPM LDS on a specific asset provides the definitive measure of the performance of the LDS. A performance estimation technique such as API 1149 may be used to estimate the performance that may be expected if the operation or configuration of the asset is to be changed. An API 1149 analysis might be used to determine if the observed performance is expected or if the observed performance indicates a problem with the LDS. The fundamental principle of the output of API 1149, an LDS's sensitivity over time, may be leveraged for both CPM and non-CPM LDSs. Sound engineering practice and experience is used when deciding whether a difference in the estimated and observed performance of an LDS is attributable to inaccuracies inherent to the estimation procedure or if additional investigation is warranted.

A special case of using more than one method (estimation and observation) is to use observed performance to "tune" or history match the inputs to the estimation technique to cause it to calculate the observed performance. Without great care, such an exercise may produce inputs to the estimation procedure that match the observations used to tune the LDS, but may not produce the correct results when used to estimate the performance of the LDS with new operations or configurations.

7.3.5 Developing Performance Targets for LDSs

Both estimation and observation are useful to determine, or at least estimate, the performance of a specific LDS applied to a specific asset. They may be applied to make generalizations about the performance of an LDS by performing the analysis for many pipelines with common characteristics, such as all those that use an LDS. For instance, a pipeline operator may deduce that their uncompensated volume balance CPM achieve X % sensitivity versus Y % for their compensated volume balance. Such a finding is obviously a simplification since each pipeline in reality has a unique performance, but generalized metrics may be useful in many instances such as making an initial choice of an LDS for an asset.

8 Testing

LDSs used in an LDP shall be tested when implemented and on a regular basis not to exceed five (5) years or when there has been a significant change in the pipeline's operation or a physical change in the configuration. The testing process shall include the requirements of LDS testing as outlined in API 1130. The requirements of API 1130 should be tailored to accommodate the unique aspects of the LDS and the specific assets on which the LDS is implemented. Also, actual leaks may be used in lieu of periodic testing, as outlined in API 1130.

The operator should determine when it is appropriate to utilize evaluation testing and/or validation testing. Wherever possible the testing should incorporate the testing recommendations of the LDS manufacturer or developers.

The importance of creating a detailed testing plan as outlined in API 1130 is emphasized here, as well as the cautionary aspects of testing also outlined in API 1130. The test plan, prepared prior to testing, should document the purpose of the test, the methods that will be employed, and the process and procedures that should be followed. LDS tests should be rigorous and be planned and executed using sound engineering and technical judgment regarding issues such as test methods employed, service fluid loss rates (when this test method is used), and situations to be simulated. The test plan should be consistent with the operational and safety policies of the pipeline operator.

For some types of LDSs, effective testing may be difficult (e.g. external LDSs) and the use of the manufacturer's testing recommendation may be critical. For LDSs such as third-party reporting, the operator may utilize a detailed checklist evaluation procedure (see API 1162 Annex E) so it is consistent and thorough. A checklist evaluation procedure may be applied to similar evaluation of other LDSs.

The pipeline operator may develop methods to test Control Room staff who respond to leak alarms. In particular, do the staff know the procedures, how do they respond to non-leak alarms and true leak indications, how do they respond to anomalies that may indicate a leak, and/or how do they respond when the LDS is degraded or has failed? The pipeline operator may use the results of this test for opportunities to improve the culture, procedures, and knowledge levels. This may provide feedback to LDP training. Knowledge or skills acquired in training are tested as a part of the training program.

9 Control Center Procedures for Recognition and Response

9.1 Overview of Procedures

The pipeline operator shall provide a documented leak response procedure to be used in the case of a leak indication on the pipeline. This procedure should be complementary to a pipeline operator's existing emergency response procedures, providing additional guidance that is specific to a leak response situation. During a leak indication, a Pipeline Controller may need to reference this procedure to ensure that the proper actions are taken.

The Pipeline Controller is an important component in the loop of responding to the LDS alarms. *49 CFR* 195.452 requires pipeline operators to explicitly declare the level of individual authority of Pipeline Controllers so they know their authority and responsibility. They are the front line for leak detection analysis and initiating action. The Pipeline Controller may or may not handle all aspects of leak detection. With complex systems, it is advisable to employ additional personnel (i.e. specialists) who are dedicated to supporting the Pipeline Controller to analyze alarms and monitor the system for correct behavior.

When developing and maintaining a recognition and response procedure for a Pipeline Controller or other Control Center personnel, there are a number of best practices that may be utilized when a leak indication occurs. This section provides examples of these best practices and guidance for implementing them.

A pipeline operator's leak detection culture should reinforce the idea that all leak indications have a cause and should be evaluated individually and as a whole (where more than one leak indication occurs). Because all alarms have a cause, they should be categorized as valid alarms, indicating that some action should be taken. The leak response procedure should outline the processes, tools, and actions that should be used by the Pipeline Controller to recognize and respond appropriately to various leak indications. These procedures should be constructed with a consequence-based mindset, with directives for taking action in the event of a leak indication. At the same time, they should be clear for ease of understanding by the Control Center personnel and concise for ease of use.

The use of flow charts may help clarify the actions specified in the written procedures. The pipeline operator's leak detection culture and training should ensure that the procedures are followed.

9.2 Recognition of a Leak

A correct and timely response to a leak indication is dependent on a Pipeline Controller's successful recognition of the conditions that indicate LOC. To that end, there are a number of indications that may initiate a leak response. It is important to note that the term "leak indication" does not always mean that an actual leak has occurred. What it does mean is that an alarm or other notifying event has occurred that suggests that present conditions indicate the possibility of a leak and that immediate action is required by the Pipeline Controller.

The pipeline operator should develop a description and action protocol for indications or combination of indications. There may be many types of LDS alarms or leak indications. The Pipeline Controller should be able to recognize the nature of the indication and then use the prescribed tools and techniques at his or her disposal to respond accordingly.

Alarm handling is discussed in detail in API 1167, Section 9.

9.3 Analysis of a Leak Indication

The procedures should specify different actions that are taken to analyze different leak indications. Therefore, it is imperative that the Pipeline Controller correctly recognize the nature of the indication or use a team approach.

During the analysis, the Pipeline Controller/team should use some or all of the following:

— follow procedures as written;

— utilize a high level of analysis;

— utilize pipeline operator-provided analysis tools (e.g. hydraulic calculations, trending, etc.);

— utilize additional expertise (perhaps as a team effort with others such as leak detection analysts or senior Pipeline Controllers);

— ensure that leadership is taken by one person;

— evaluate the information provided by complementary or alternative LDS;

— recognize conflicting data, and how those data may influence the analysis;

— increase level of scrutiny where there are low credibility alarms or work is being performed on the line;

— know what to monitor and look for, and what tools to use regarding leak indications;

— whenever possible, use an independent means of verifying the cause of the leak indication (the pipeline operator designates what constitutes an independent means);

— apply their knowledge of the function of the LDS or technique that alarmed;

— during the analysis, apply their knowledge of the unique operating aspects of the pipeline that has the alarm;

— with caution, recognize that leak indications may be attributed to non-leak reasons;

— apply shutdown rules if warranted.

Depending on the operating conditions and the nature of the leak indication, it may not be immediately apparent that an actual LOC has occurred. Most leak indication responses that do not require an immediate shutdown of the pipeline involve a limited period of analysis during which the Pipeline Controller checks a variety of conditions that may have triggered the alarm (data failure, irregular operating condition, etc.). The leak response procedure should include methods (for example, pressure trend analysis) and tools (for example, a hydraulic calculator) to aid in determining the cause of the leak alarm. During this period, the Pipeline Controller may request team support to analyze the leak indication and document the actions.

For leak indications that do not require an immediate shutdown of the pipeline, the leak response procedure may specify a predefined time limit or volumetric limit to investigate the leak indication before further action is initiated. The pipeline operator may specify different time limits or volumetric limits for each individual pipeline LDS or for the sake of simplicity may define a single limit for all pipelines. In either case, the limit specified should be based on rational analysis of the pipeline LDS to ensure a safe and timely response. It should be understood that the Pipeline Controller is not required to wait for the time limit to expire or volumetric limit to be exceeded before taking action. If the Pipeline Controller has sufficient reason based on the available information and tools to suspect that a leak is occurring, it takes immediate action to respond to the leak indication.

If the analysis and investigation finds that the cause of the leak indication was due to some condition other than a hazardous liquid product leak, the indication may be cleared and the pipeline may resume normal operation.

9.4 Response to a Leak Indication

9.4.1 Response General

The occurrence of a leak indication should compel a Pipeline Controller to take immediate action, as this is a reflection of the pipeline operator's culture. As previously noted, the Pipeline Operator may specify different actions are taken to respond to different leak indications. For example, an operator's leak response procedure should dictate that certain leak indications require an immediate shutdown of the pipeline while other indications may dictate that the Pipeline Controller take additional action to analyze the current pipeline operation or escalate the investigation to other SMEs to determine the cause of the leak indication before a shutdown is required. In addition, the indicated magnitude of the leak, the persistence of the leak indication, and the level of risk involved may be the key factors in determining the action a Pipeline Controller should take as documented in the pipeline operator's leak response procedures.

When either the initial analysis of the leak indication has concluded, or if the time limit or volumetric limit to determine the cause of the leak indication has expired, the Pipeline Controller should take the appropriate action based on the analysis and understanding of the leak indication.

Leak response procedures should recognize that a leak indication may be triggered from a number of different sources. The procedures should characterize the leak indicators to the best extent possible so that common language is used. Through procedures and training, Pipeline Controllers should have a detailed knowledge of their role and responsibilities during a leak indication and should be able to evaluate the credibility of the leak indication.

The response may differ based on the characteristics of the particular pipeline on which the indication is noted (i.e. an indication that normally requires a limited period of analysis before a shutdown, which is required on most pipelines, may require an immediate shutdown on a given line). In general, leak indications are announced through LDS-generated alarms and may be recognized through data analysis (hourly reports, pressure trends, etc.) or based on reported evidence of a leak (field surveillance identifies product in ROW, dead vegetation, neighbor reports smell of gasoline, etc.).

A typical response procedure should include directions to take actions that the pipeline operator deems to be safest and most appropriate for the pipeline in question, which, in most cases, should be to shut down and isolate the pipeline segment in a safe and controlled manner where the leak is suspected to have occurred. Further investigation of the leak indication and operational data may continue until independent leak verification has been confirmed or disproved. This may include a field visual assessment of the affected assets and/or an asset integrity verification procedure.

In the case of an actual hazardous liquid product leak, the pipeline shall only be restarted for normal operations once the leak condition is repaired, the operator has determined the conditions do not preclude operations, and restart authority has been granted according to the operator’s procedures.

9.4.2 Leak Indications Requiring Immediate Shutdown Response

The first category of response is to alarms or indications (single or multiple) that are clear and credible and, as such, require either a directive to immediately shut down the pipeline or allow only a very limited time before a shutdown is required. Characteristics of the indication may include, but are not limited to:

— has a clearly defined signature,

— has a high degree of credibility,

— Pipeline Controller has a high measure of confidence in the leak indication,

— indication has a high measure of reliability.

An operator may decide that all leak alarms should be reason to shut down the pipeline, but this sort of directive is determined by an individual operator’s strategy.

9.4.3 Leak Indications Allowing Additional Analysis Before Shutdown

An operator may have a second category of alarm response where alarms, notifications, or a combination of indications require timely investigation and preparation for shutdown. These instances include but are not limited to the following.

— Indications at an intermediate location that are not supported by overall hydraulic conditions (i.e. flow upstream and downstream are correct).

— Loss of function of the leak detection technique (e.g. heartbeat alarms).

— Communications outages at time of alarm.

— Data fault or data outage alarms.

— Low-credibility alarms from surveillance or third-party reports.

— A CPM deviation warning (not all LDSs have these type of alarms) that indicates a deviation that is not yet above leak threshold.

— Alarms that occur while calibration or other work is occurring on the pipeline in the area of the work.

— SCADA function alarms.

— Manual method (non-CPM) deviations such as over/short calculations that are not supported by leak detection alarms.

— Alarms that cannot be verified by call-outs in field.

— Visual sensors indications.

— Surveillance leak indications with no show of hazardous liquid or related effects (i.e. vegetation indications).

— Alarms that occur when a new hazardous liquid is introduced.

— Alarms that occur when a new or unusual flow path is used.

— Alarms that coincide with start-up/shutdown or rate changes.

— Instances where pumps shut down automatically or may not start due to low pressure.

— The reaction of the line when set point changes are made.

— Abnormal operating conditions; for example, radical unexplained pressure/flow deviations.

— Alarm repeats.

— Over/short calculations and trends.

— SCADA rate-of-change alarms or indications.

— Alarms with uncertain causes that the pipeline operator determines require shutdown and investigation afterward.

— Column separation indications that are occurring where it is an unlikely possibility.

9.5 Validating the Leak Indication

Leak validation is triggered by the suspicion that a leak exists and examines the pipeline and/or analyzes pipeline operation data in order to verify and make a formal determination of the existence of a leak or alarm cause verification. Examples of leak validation/cause verification include, but are not limited to:

— hydraulic calculations,

— pressure and flow monitoring (trending),

— CPM LDSs,

— externally based real-time LDSs,

— real-time video feed that is continuously being analyzed,

— aerial surveillance,

— ground surveillance (foot patrol),

— internal pipeline inspections,

— external pipeline inspections,

— pressure testing (shut-in testing/stand-up testing) where this is possible.

9.6 Reporting and Documentation

During and/or after a leak alarm, a leak indicator, or a confirmed leak, the actions taken should be documented. The abnormal operating condition and actions taken to mitigate the issue should be documented per a pipeline operator's response procedures. A standard form should be provided to assist with documenting the events and timeline. Details may include, but are not limited to:

— event timeline and duration,

— classification of the indication (leak or non-leak alarm),

— date/time of the indication,

— location of the indication on the pipeline,

— what triggered the leak alarm (which may be unexplainable),

— hazardous liquid being transported,

— consequence/impact of the indication,

— pipelines and facilities involved.

For a confirmed leak, the pipeline operator should reference their Emergency Response Plan requirements for the pipeline operation, as applicable and may document this additional information:

— information from Field Operations;

— emergency notifications issued with date and time;

— chronology of communications between stakeholders;

— teamwork participants during the analysis;

— reporting agencies contacted date and time;

— estimated leaked volume;

— metering logs of a duration to cover before and after the indication;

— pressure logs of a duration to cover before and after the indication;

— pump statuses and valve position logs of a duration to cover before and after the indication;

— alarm/events logs and trends;

— Pipeline Controller logbook/notebook and turn-over logs;

— SCADA and leak detection data capture;

— cause of the event (human error, faulty equipment, leak, pigging operation, column separation, drag reduction agent (DRA), atypical operations, new commodity, etc.);

— what LDS caught the leak;

— leak source and component;

— contributing factors;

— ambient and pipeline temperatures.

The documentation may be used by the pipeline operator's investigation team to thoroughly investigate the events and take the appropriate actions to identify and address the leak indication. The documentation is also used in alarm management (see Section 10).

9.7 Pipeline Restart

It is the pipeline operator's responsibility to clearly define what is required prior to a restart, including any required regulatory action associated with the event such as a corrective action order. Requirements may include physical/ visual inspection, shut-in testing/stand-up pressure monitoring for a predetermined amount of time, or other appropriate sources or methods of ruling out a leak condition. At the end of the investigation, the pipeline operator should fully understand the cause of the leak indication and have verified the cause. A pre-start-up safety review may be needed if any modifications (permanent or temporary) have been made to the system.The operator's procedures and appropriate stakeholders should be engaged and formal documented approval granted before any restart is authorized.

The Pipeline Controller should maintain a high level of awareness when a pipeline that has been shut down is restarted. Extra attention should be given by both field personnel and the Control Center staff during and after the restart process to help confirm the absence of a leak. This restart procedure is not a part of detecting the leak but shall be part of Control Center procedures. It should cover requirements for:

— restarting the pipeline after the investigation finds no evidence of a leak and

— restarting the pipeline after the leak has been repaired.

Documentation may include a restart checklist. This checklist is to be used to verify that the issue has been resolved and that it is safe to restart the line.

10 Alarm Management

10.1 Alarm Management Purpose

Alarm management employs tuning and threshold setting methods driven by pipeline analysis, data collection, and review. It may make use of statistical alarm techniques and advanced analysis. Alarm management should encompass methods aimed at increasing Pipeline Controller responsiveness by increasing reliability of alarming and maintaining the LDS performance.

Alarm data collection and categorization evaluates post-alarm actions to capture the information recorded by the Control Center at the time the alarm occurred and to add additional information to create an accessible database of leak alarm information and build an alarm history that may be used for alarm review. Immediate handling of leak detection alarms is the function of the Control Center procedures in the previous section. As noted in API 1167, Section 4.5, leak alarms should be one criteria when establishing the criterion for identification of safety-related alarms.

Alarm review is the process of analyzing the alarms with the goal of increasing the confidence of the alarms. The alarm review should evaluate the KPIs associated with the leak alarming and may point to possible further action (e.g. threshold setting) or improvements within the pipeline operator.

Threshold setting evaluates the existing thresholds and, based on the alarm review, the need for adjustment of the thresholds to maintain the performance according to the specified or expected metrics of sensitivity, reliability, robustness, and accuracy. Threshold setting acknowledges the expected thresholds from the selection, the cause of the alarm, and what process may be undertaken to adjust any thresholds to ensure the required metrics and KPIs based on pipeline operator's culture and strategy are achieved or maintained. Alarm threshold settings should not be adjusted outside the range of upper and lower design limitations.

Tuning is adjusting the leak detection technique for more precise functioning, or target performance per the pipeline operator's strategy. Tuning is normally undertaken when an LDS is initially installed and may continue for some time. Tuning may occur when changes are made to leak detection inputs or the operation of the line changes or to attempt reduction of non-leak alarms.

10.2 Data Collection

Alarm data collection requires the gathering of all the information that was recorded in the Control Center during the handling of the alarm and adding to that information additional data that may be used during alarm review.

Alarm data collection should categorize the alarm as to cause and refine the category or confirm the category given by the Control Center.

The alarm data collection should record particular information on the Control Center response to the alarm. For example, did the Control Center follow procedures and what tools or additional assistance were utilized to determine the correct alarm response? A good example may be whether teamwork was employed during the analysis.

The operator may decide that for a particular alarm, capture of additional data, or analysis of the alarm beyond the analysis undertaken in the Control Center may not be required.

10.3 Categorization

Clarity and credibility of leak detection alarms should be a primary factor in categorizing alarms. Review of KPI facts may be helpful in categorizing actions.

Alarm causes should be determined or confirmed for relevant alarms so that a proper determination of possible adjustments may be made.

Alarm categories may be:

— alarms that required immediate action to shut down the pipeline, or high-credibility indications;

— alarms that required an immediate investigation and preparation to shut down or lower-credibility alarms;

— alarms that were proven to be non-leak alarms.

This may be the desired way to divide alarms for the Pipeline Controller, but further categorization may aid in the review process and in improving the LDS and response (i.e. increased granularity is desirable).

Other possible alarm categories or subcategories may be cause-based—examples are as follows.

— Data failure with a further breakdown to the equipment level; for example, meter failure, communications failure to pressure transmitter, temperature out of range, or meter prove error.

— Operational issues with a further breakdown into items such as filling a new spool piece on the manifold, new product type from supplier, fluid at much warmer temperatures than normal, or instrument calibration.

— Modeling/tuning issues where the non-leak alarms that were generated may be prevented by some form of tuning/adjustment to an LDS, with a further breakdown into items such as dynamic threshold adjustments during transients, temperature model tuning, or product property tuning.

API 1130, Section 6.1.1 (Types of CPM Alarms) divides alarms into three classes: data failure, irregular operating condition, and possible leak. Ideally, the categorization of the alarm into one of these three classes should be made by the LDS, as the categorization of the alarms help justify the LDS credibility and sensitivity of the LDS. The types of alarms should be applicable to externally based LDSs.

Table 3 is an example of information that may be useful in alarm data collection or in the alarm review that follows, but is not all encompassing.

Sufficient information should be captured so it is possible to determine what adjustments may be made to improve the leak detection alarms and response. For example, a data failure may be the result of: SCADA failure, a software interface failure like (e.g. OPC/Modbus/TCP-IP), a communications outage, a PLC failure, power failure, cable break, or an instrument failure.

Table 3—Alarm Category Table

Category	Definition	Response	Further information
Leak	LOC	Followed Procedure	Location, size, cause
Expected Field Work	Alarm due to field work with prior knowledge	Followed Procedure	What was being worked on
Infrequent Operation	Alarm due to new or infrequent operation	Followed Procedure	What is different or new
Instrument Failure	Alarm due to instrument failure	Followed Procedure	What failed
Column Separation	Column separation causing an alarm	Followed Procedure	Start-up or flowing with column separation
No Call-in	Alarm due to field work with no prior knowledge	Followed Procedure	What was being worked on

10.4 Alarm Review

10.4.1 Goals of the Review

The ultimate goal of alarm review should be to:

— drive up the number of clear and credible alarms or drive down the number of uncertain alarms;

— look for improvement possibilities;

— look for learning possibilities (for the Pipeline Controller, SCADA, engineering, field operations personnel, HSE (health, safety, and environment), compliance, and any other relevant stakeholders);

— determine if threshold changes are required;

— reduce other non-leak and chattering alarms, which may enable the Pipeline Controller to enter pertinent data in a timely manner.

After the initial alarm response review, all leak alarms should be reviewed periodically. The intention of the review is to determine what adjustments may be made to make the leak alarm response and the LDS more timely, accurate, and robust. Alarm review should use the information provided by alarm data collection to perform an analysis.

The leak indication may be reviewed with a mindset of looking for opportunities to improve the processes and performance of the leak indication response. For example, did the field and Control Center respond properly and follow up on all pertinent issues, should Level 1 through 4 KPI classifications be updated, etc. Lessons learned should be documented and made readily available for future leak indication response efforts. If appropriate, the events may be used as a training example for operations personnel (Control Center and field) in the future. The alarm review may examine the Control Center alarm interpretation and response actions.

It is suggested that the pipeline operator perform both short-term periodic reviews (daily, weekly, or monthly) of alarms and long-term periodic review (for example, a five-year cycle) of alarms. The evaluation may indicate what to do strategically in managing the types of alarms. This information then feeds into improvement planning.

10.4.2 Short-term Periodic Review (Daily, Weekly, Monthly)

The purpose of the short-term review is to determine how the LDSs are performing and the operator's response. The short-term review may include:

— review of alarms, threshold trends, and imbalance trends and causes over some defined time period;

— analysis of imbalances, threshold, line pack and meter over/short (flow balance) during pipeline start-ups and shutdowns, pump starts/stops, movement changes, valve close/open, column separation condition, process variable changes, etc.;

— analysis of measurement trends (pressures for the segment of pipeline that issued the alarm, meters/flow rates, temperatures, densitometers, process variable, etc.);

— reviewing of response to the alarms and the procedures.

The result of this review may result in short-term actions intended to improve the accuracy, reliability, and robustness of the LDS. It may result in recommendations to improve the response to the alarm (more training, adjust the procedure, etc.). For instrument failures or PLC failures, the review may result in work orders of the correct priority to repair the affected equipment. If notification of field work did not occur as per procedure, the action may be a follow-up with the individuals involved to ensure that they know the procedure and how to follow it for planned field work.

The pipeline operator should document the results of the short-term periodic review.

10.4.3 Long-term Periodic Review

Periodically, with the time between reviews not to exceed five years, the pipeline operator should complete a review of the alarm performance and thresholds of each LDS. The purpose of this review is to assess the alarm performance and thresholds from the perspective of sensitivity and reliability, and the appropriateness of the thresholds of the LDS with respect to the KPIs and performance metrics. While terms used in this section, for example, "threshold" and "imbalance", typically apply to internally based (CPM) LDSs, they may be applicable to other non-CPM LDSs such as over/short calculations.

The frequency of the long-term periodic review should be based on a risk-based analysis. This frequency may be uniform for all pipelines, or may be pipeline dependent. This risk-based analysis may include the following:

— pipeline operator's risk tolerance,

— frequency of major/minor changes on the pipeline,

— frequency of testing,

— complexity of pipeline operations,

— presence of occasional column separation operation,

— robustness of the process control system or network.

As a requirement of the process, the pipeline operator should determine which KPIs defined in the overall performance section (Section 13) should be used as part of this long-term periodic review. Levels 3 and 4 may especially apply. In conjunction with that, the pipeline operator should define the measures to be used to evaluate each KPI and the data collection method and frequency for those measures.

In addition to the KPIs and the above data, the long-term periodic review may include:

— LD metrics as per API 1130 (accuracy, reliability, sensitivity, robustness);

— actual leaks;

— withdrawal tests;

— simulated testing;

— stakeholder reviews;

— need for equipment additions/replacements;

— need for leak detection method additions/replacements;

— need for operational changes (alarm response, avoiding column separation, etc.);

— need for KPIs and target adjustments;

— need for more training;

— whether the field and Control Center responded properly and followed up on all pertinent issues;

— whether there was any confusion or items missing in procedures;

— whether Level 1 through 4 KPI classifications should be updated;

— lessons learned.

Attention should be paid to how the results of short-term periodic review feeds into the long-term periodic review. This feedback may influence the frequency of the short-term periodic review. For example, the classification of the alarms and alarm cause codes may be the result of the short-term periodic review. Some or all of these findings may be clearly evident in the short-term review. Action based on clear indicators should occur in the short term and not be delayed until the long-term review is conducted.

The pipeline operator should document the results of the long-term periodic review.

10.4.4 Actual Leaks

In the event of a confirmed leak, the LDS shall be analyzed, the response of the LDS evaluated, and the result documented. This may be an opportunity to review the response of the Control Center to the leak. The result of the LDS is dependent on the characteristics of the leak. General classifications for review of actual leaks may include classification by the following.

Within LDS scope:

— the leak signature is significant enough to be detected by the LDS, but the LDS failed to detect the leak;

— the LDS successfully detected the leak.

Out of LDS scope (outside of the physical boundaries of the LDS; example: upstream of an injection flow meter):

— leak rate is small enough that there is no observable leak signature in the LDS input data;

— leak rate is small enough that the leak signature is indiscernible from typical system noise.

If the LDS successfully detects a leak, a thorough analysis shall be performed as there may be valuable lessons learned or areas of improvement identified.

If the LDS failed to detect a leak that is within the scope of the LDS, an investigation shall be performed to determine the cause of the LDS failure and identify corrective actions to be taken. Depending on the root cause(s) or contributing factors of the LDS failure, corrective actions may include a long-term review being performed. The investigation could include review of previous non-leak alarms on the pipeline segment, functioning of the LDS tool during normal operations, verification of the LDS tool functionality operating within normal parameters, and verification of all configuration parameters. The investigation may include a review of any possible issues with data communication to or from the LDS software or issues with SCADA pre-processing of data used by the LDS tool. The pipeline operator should make changes and test to verify the leak detection method is functioning as intended for the specific timeframe.

The alarm review may indicate tuning rather than threshold adjustment. The alarm review may indicate having dedicated LDS alarm analysis personnel to relieve the Pipeline Controller of the LDS alarm burden, having better sensitivity at expense of more alarms, and helping document the reason(s) for the alarm notification.

10.5 Threshold Setting

Ideally, threshold setting involves decreasing the detection threshold level so the LDS becomes more sensitive. However, threshold setting may involve increasing thresholds or desensitization. Threshold setting differs from tuning. Note that threshold setting only applies to systems that have the feature of adjustable thresholds.

Threshold setting acknowledges the threshold expectations from the selection process, performance monitoring results (particularly test results), and input from the Control Center and its staff to set usable detection thresholds for those LDSs that have adjustable thresholds. The threshold setting understands the leak detection strategy, ensuring that the thresholds used align with what the pipeline operator has specified.

There is an inherent tension between reliability and sensitivity. As sensitivity is improved (solely by lowering thresholds), reliability may be decreased (increasing non-leak alarms). The adjustment of leak detection thresholds to reduce the sensitivity and increase reliability of the internally based leak detection method may perhaps be done in conjunction with the addition of complementary or alternative LDSs to compensate for the reduced sensitivity. A higher alarm rate may be acceptable if good diagnostic tools are provided or if additional information is provided that may be used to verify or disqualify alarms.

Non-leak alarms beyond the KPI value set earlier in the process outlined in this document may be a driving factor in determining if adjustments are needed to the LDS.

Threshold setting may use the following.

— *Reliability-focused philosophy:* define a tolerable alarm limit (i.e. a targeted number of alarms) and adjust thresholds until you hit the alarm limit. This may result in poor sensitivity.

— *Sensitivity-focused philosophy:* define sensitivity targets and set thresholds to meet those targets. This may result in poor reliability.

— *Balanced philosophy:* Set both alarm limits and sensitivity targets. If both cannot be met through threshold tuning, other methods may be required to reach targets, such as new instrumentation, hydraulic model tuning, or operational changes.

Leak indication thresholds may be changed or adjusted on a temporary basis. It is important that the required or desired performance metrics be acknowledged when thresholds are changed, changes are documented, and the MOC process is followed.

Dynamic thresholds, a type of threshold adjustment, may be utilized provided they are understood. The current threshold should be displayed to the Pipeline Controller. This may be a primary feature of the LDS where the LDS dynamically adjusts the threshold to provide large volume leak detection during transitions of flow and pressures during the pipeline operation, which are typically during pipeline startup or shutdown. The dynamic threshold automatically reduces the threshold, typically significantly, when the pipeline is operating in steady state.

Short-term threshold changes to suppress alarms by threshold adjustment should be discouraged. However, maximum limits for adjustment may be established and there should be a threshold notification to alert the Pipeline Controller that an adjustment is active. There should also be a process that returns the threshold to normal. The supervisor should be advised that the threshold will or has been manually adjusted and the reasons why. The time the adjusted threshold was in effect should be logged. Ideally, the supervisor’s approval may be required.

The pipeline operator may implement changes that do not adjust the thresholds before threshold changes are contemplated. To reduce non-leak alarms or improve functionality, possible changes may include:

— equipment preventative maintenance or replacement (failed pressure or temperature probes);

— modification of operation (minimize column separation conditions; for example, by maintaining a packed pipeline on shutdown or packing a pipeline before beginning operation);

— implementing a complementary LDS;

— providing more analysis tools and resources to the Pipeline Controller;

— instituting dynamic alarming techniques within the leak detection alarming schema.

Note that dynamic alarms do adjust thresholds, but only on a temporary basis. The primary or steady state threshold is not changed.

There should be a well-planned and conducted review process that may include, but is not limited to, the following.

— Determining if thresholds are too tight vs. too loose, e.g. use feedback from Pipeline Controllers and/or shift leads. The goal is to gain Pipeline Controller confidence.

— Evaluating operational changes to reduce impact on leak detection, e.g. change an operation that causes alarms.

— Determining if the alarms are due to some normally recurring conditions. Are the alarms so numerous that the LDS credibility is affected?

— Weighting short-term vs. long-term review input.

— Providing/receiving feedback to/from Control Center.

— Finding changes that do not affect the leak detection technique.

— Determining if a complementary LDS or enhancement to the LDS may solve the uncertainty.

If it has been determined that thresholds should be adjusted (either short term or long term), the pipeline operator may do any one of the following:

— make the changes offline and test before implementing,

— make a change to only one of the LDSs and leave others at existing thresholds,

— ensure that the change is in line with strategy,

— evaluate LDS and make minimum changes,

— attempt tuning instead of threshold changes,

— perform calculations (e.g. using API 1149) to determine what may be the minimum change,

— compare to threshold expectations from the selection process,

— make no threshold changes where they are specifically not allowed on the particular LDS.

The pipeline operator should use procedures for any threshold change and it is particularly important that they inform the Pipeline Controller and Control Center of any changes.

Rupture alarm thresholds are a special case. Rupture thresholds are set to alarm with high reliability. API/AOPL White Paper Liquid Pipeline Rupture Recognition and Response contains a discussion on this topic.

10.6 Tuning

Tuning may be an option to lower thresholds without increasing alarms. Tuning is a slow process in which one or a limited number of tuning factors are changed and the LDS is left to run until it is certain the changes may be evaluated. Tuning may be performed by the pipeline operator or by the vendor of the LDS. If the pipeline operator undertakes the tuning, the methods suggested by the vendor may be used as a guide. It is critical that as-existing tuning factors and as-changed tuning factors are recorded. The evaluation after changes should be formal and the results should be documented. Tuning may involve repeated iterations until an optimum performance level is achieved.

Tuning may involve alarm prevention changes to software at the SCADA or PLC level or by making changes to pipeline hydraulics (i.e. installing a backpressure control valve to eliminate column separation). Implementing data filters to prevent some alarms may be a form of tuning.

Tuning is not calibration, but does achieve improved performance. Most often, tuning is applicable to CPM LDSs but may also be applied to externally based LDSs. CPM LDSs often have a large number of tunable factors and the tuning involves changing the weight of one factor in relation to the others. Tuning may be pipeline-specific, so even if the same LDS is used on various pipelines, the tuning factors may be different. Optimally, LDS tuning is performed offline with a data set large enough to encompass expected seasonal and flow regime variations.

There may be many opportunities for tuning: when software or hardware is updated or patched, when improved instruments are installed, when additional instruments are installed, and when there are more data inputs to the LDS.

11 Roles, Responsibilities, and Training

11.1 Roles and Responsibilities

Prior to developing a training program, pipeline operators should define key stakeholders' leak detection roles both within their organization and externally (i.e. public, landowners, etc.). Stakeholders may have many other roles and responsibilities. This section covers those roles that relate to leak detection.

Pipeline operators should have clear descriptions of their stakeholders' roles and responsibilities. This helps the stakeholder(s) understand their areas of responsibility and the pipeline operator's expectation(s) of them to comply and complete the task(s). Clear descriptions of roles and responsibilities allow the individual and/or group to understand how they support the leak detection strategy and where they contribute to the leak detection culture. Teamwork may be improved when those who are involved in leak detection understand others' roles and responsibilities.

Pipeline operators may have the same name for the same functions (i.e. Pipeline Controller because it is a common name used in standards). However, different names are often used for others who are involved with leak detection and even different responsibilities for employees even when the same function name is used. Because of these differences, it is not possible to accurately describe the roles and responsibilities for all employees and stakeholders. The roles and responsibilities names and descriptions used in this section are examples only. A brief description of the roles of those involved in leak detection and a list with many of the common names related to leak detection that are used is shown in Annex E. These are listed in relation to the department, section, or functional area where they may be used.

For the various LDSs in use by the pipeline operator, there may be additional and specific defined roles and responsibilities for the staff that use and support the particular leak detection method.

Changes to roles and responsibilities should be tracked and reported using management of change.

A pipeline operator may find it useful to develop a RACI chart (see Table 4). The chart lists the key stakeholders and whether they are (R) responsible, (A) accountable, (C) consulted or (I) informed about aspects of the LDP. The training program for those who are accountable or responsible will be at a much higher level than those who are consulted or informed. This RACI chart may not align exactly with the stakeholders names used in the training sections that follow, because it is an example only (see Annex E for a list of industry names).

11.2 Training

11.2.1 General

An effective training program has the potential to greatly reduce the consequences of a pipeline leak, particularly at the Control Center level.

Table 4—RACI Chart

API-1175								
Stakeholders / Responsibilities	**Management**	**Control Center**	**Analyst**	**Engineering**	**IT Group**	**SCADA Support**	**Field Operations**	**Public / Land Owners**
Aerial Surveillance	A						R	
Alarm Management & Threshold	A	R, C, I	I	R		R, C, I	I,C	
Culture / Strategy	R, A	I, C	I	C, I	I	I	I	I
Design	A	I, C	I	R		C, I	I	
Emergency Response	A	R, C, I		R		I	R	I
Performance	A	I	C	R, C, I		R, C, I		
Record Keeping & Reporting	A	R, C, I					R	
Restart Authorization	R, A	C, I		I			C, I	
Leak / Rupture	R, A	R, C, I	C	C, I			R, C, I	
Testing	A	C	C, I			R	R	
Training	A	R	I			R	R	

A pipeline operator's personnel and external stakeholders who interact with any part of its LDP should receive appropriate initial training, retraining, and refresher (aka recurring) training.

The level, content, method, frequency, and testing/verification of the training may be based on the roles and functions of the individuals and to support the pipeline operator culture and strategy. Training metrics may be established to ensure training effectiveness.

The specific level and the content of training received may be based on the role that an individual has in the pipeline operator's LDP.

The methods used to deliver training should be appropriate to the role of the individual in the pipeline operator's leak detection strategy and the depth of training required. The most intense levels of training are for the Control Center staff and the greatest number and variety of methods should be used with these individuals.

See Annex F for an example of a training program, listing of the level and content of training recommend for each role, and recommended training delivery and testing/verification methods.

Frequency of training and training metrics is outlined in this section.

One of the important aspects also outlined in this section is team training. Employees should be trained to work together effectively as a team.

11.2.2 Roles and Functions

All personnel in the roles identified in 11.1, Roles and Responsibilities, should receive training. Not all pipeline operators have the same organizational structure or names for those functions (see Annex E). Each pipeline operator should define the role requirements based on the size and complexity of its pipelines and LDP (see Table 5). For this section, the structure discussed in 11.1 is used as an example (with some additional subdivision).

Table 5—Role and Content of Training

Role	General Training Content
Management	Culture, Management, Reporting, Broad Operational, and Broad Technical
Control Center	Culture, Management, Reporting, Detailed Operational, and Broad Technical
Analyst: Leak Detection Staff	Culture, Management, Broad Operational, and Detailed Technical
Engineering: Support Staff	Culture and Detailed Technical
IT Group	Culture and Detailed Technical
SCADA Support	Culture and Detailed Technical
Field Operations: Field and ROW Staff	Culture, Reporting, and Area-Specific Technical
Field Operations: Connecting Facilities Staff	Reporting and Area-Specific Technical
Public: External Response	Reporting and Area-Specific Technical
Public: Government Agencies or Regulators	Culture, Reporting, Broad Operational, and Broad Technical
Public: Land Owners/ROW Users	Reporting

11.2.3 Team Training

Team training prepares people to work efficiently and effectively as members of a group. The emphasis during team training is on effective communications amongst all stakeholders who would be involved in leak indication investigation.

Training as an integrated team in an exercise that includes all pertinent levels of authority as may be defined in a response procedure is important. The team is presented a scenario and is to respond through the use of associated documentation and/or procedures.

The parties involved may include: Control Center staff, all support staff, field staff, management, and external emergency support response. In addition, there may be simulated reporting, coordination, and interaction and with government agencies, regulators, and the public.

A tabletop format may be used with all players in a single room, or a combination of tabletop and field exercise may be appropriate. Team training should focus on the functioning of staff as teams, not as a collection of technically competent individuals. The intent is to train, evaluate, and improve response as an integrated team in as realistic an environment as possible.

The importance of clear and unambiguous communication should be stressed in all training activities involving all roles on the team. This training should test and emphasize the abnormal and emergency roles and functions of all of the personnel involved in the exercise. The scenario should test the effectiveness of procedures for elevating the Pipeline Controller's support beyond the Control Center within the time constraints of those procedures. A formal script and separate evaluators are recommended. One of the best techniques for reinforcing effective human factors practices is careful debriefing of the exercise and highlighting the processes that were followed. Additionally, it is essential that each team member be able to recognize good and bad communications and effective and ineffective team behavior.

Evaluation of the team's performance during the exercise should include an assessment of the degree to which the team avoided engaging in groupthink. Avoiding groupthink is important in the early diagnosis phase of a leak and throughout the entire response phase. The longer a response takes, the greater the possibility that groupthink may occur. An SME in organizational behavior may be employed to observe and evaluate the exercise to detect this phenomenon and the interpersonal communication, leadership, and decision making during the exercise.

11.2.4 Training Frequency

11.2.4.1 Establishing Intervals and Extent

The pipeline operator should establish an interval for retraining and refresher training, as well as outline the extent of training for all individuals who interact with the pipeline operator's LDP.

11.2.4.2 Refresher Training

Refresher training is an abbreviated form of the initial training and is independent of retraining. The primary audiences for refresher operational and technical training should be Control Center staff and leak detection staff. Additionally, each pipeline operator may establish refresher training frequency for roles receiving leak detection basics and awareness levels of training. Decision factors for refresher training may include:

— size and complexity of the pipeline operator's pipelines and LDP;

— a leak indication or drill;

— validation testing outcome of previous training;

— a fixed frequency for Control Center and LD staff, particularly for alarm attribution skills;

— team training exercises at regular intervals.

11.2.4.3 Retraining

Retraining is completion of all parts of the LD training program for the role and may be used for an individual who has been out of a role for period defined by the pipeline operator. Specifically for Pipeline Controllers, that period should match the period that the pipeline operator established under its OQ program for other qualifications. Retraining may include the following.

— Levels of decision-making and shutdown authority.

— A leak indication or drill.

— Management of change (see Section 14, Management of Change). As a formal part of the pipeline operator's MOC process for a proposed change affecting its LDP, the LDP training program should be reviewed/updated and re-delivered.

— Validation testing outcome of previous training.

11.2.5 Training Metrics

Training is a soft, proactive barrier to undesired events involving a pipeline operator's LDP such as degradation, misdiagnosed non-leak and actual leak alarms, and non- or improper response to an actual leak. A pipeline operator may establish KPIs that measure both the quantity and effectiveness of the training. These are leading KPIs that are recommended to be within Level 4 (operating discipline and management system performance indicator) of the pipeline operator's Process Safety Indicator Pyramid (see Section 13, Overall Performance Evaluation of the Pipeline operator's LDP).

These items may be measured:

— percentage of personnel in each role receiving the proper training;

— validation testing scoring;

— correct diagnoses of non-leak alarms;

— correct procedural response to alarms;

— student evaluation of training effectiveness;

— feedback from ROW landowners, public, ROW users, and external emergency responders.

12 Reliability Centered Maintenance (RCM) for Leak Detection Equipment

12.1 Maintenance Overview

Pipeline operators should establish written policies and procedures to ensure that all components of the LDS and their supporting infrastructure components are designed for reliability and maintained appropriately.

The maintenance should cover both externally based and internally based LDSs and all components associated with all LDSs in use by the pipeline operator. These components include field measurement and instrumentation (e.g. pressure, flow, temperature, density sensors, valve and pump instrumentation, cables, etc.), communication systems (e.g. network hardware, communication media, etc.), processing units (e.g. SCADA/DCS hardware and software, flow computer/PLC, hardware and software, and leak detection software), and backup systems.

The process should include scheduled maintenance that is a part of a pipeline operator's policy and existing RCM program. Also, there should be a process for immediate maintenance and repair of LDS components that have failed or are providing inaccurate or "bad" readings. Sometimes the LDS behavior is the best indication when maintenance is required. The maintenance plan may call for servicing instrumentation when the LDS behavior, limits, and output are affected.

The term "reliability" is often generally used to reference availability and maintainability. Reliability for instrumentation is defined as the likelihood of a failure occurring over a specific time interval. "Availability" is a measure of something being in a state of readiness for its intended task (i.e. availability for mission). "Maintainability" is the parameter concerned with how the LDS in use may be restored after a failure, while accounting for concepts such as preventive maintenance and diagnostics (built-in tests), required maintainer skill sets, and support equipment.

12.2 RCM Process

During the maintenance planning process, it may be helpful to discuss the LDS and maintenance program with the users of the LDSs and/or with vendors.

The maintenance program and process may include the following questions.

— What is the function of the particular item or component and what is its associated performance standard?

— In what ways may it fail?

— What are the events that cause each failure of that component?

— What happens when each failure occurs?

— In what way does each failure matter to the LDS?

— What procedures may be implemented to prevent consequence of failure (an active prevention approach)?

— What may be done if a suitable preventive task cannot be found?

These facets co-outline a RCM process and align with FMEA approach. A useful reference is SAE JA101, Evaluation Criteria for RCM Processes.

The reliability assessment may include the following.

— Understanding all failure mechanisms and the probabilities of each failure listed in the FMEA and the confidence of each failure as a function of time.

— Physics of failure models that align the probability of failure to root causes.

— Overall reliability model. This may be one of several forms:

  — a bow tie diagram;

  — an FMEA, event tree, or fault tree;

  — a reliability model of system components to system (mixed series and parallel).

In each LDS, components may require specific calibration hardware, training, and skills to successfully maintain them. Policies and procedures should be written and followed to ensure that each component is properly maintained and contributing positively to the robust and reliable performance of each LDS.

The written policies may be a combined document or separate documents for each component. In either case, the objective is that clear concise information be included to identify the maintenance personnel's qualifications, roles, and responsibilities, as well as design and maintenance criteria for all components of a LDP. Where applicable, documentation may make reference to pipeline operator maintenance manuals. For example, some topics such as instrument calibration are likely covered in a pipeline operator's maintenance manuals.

12.3 Leak Detection Component Identification

All components integral to the reliability of a LDS should be identified and documented. These components may be physically tagged and/or their corresponding tracking database tags flagged to signify that they are components of the LDS. A common database naming practice for all leak detection database components may be used. API 1130 specifically addresses CPM instrument identification.

12.4 Design

Design for Reliability and Maintainability (DfRM) is a closed-loop process that may use the following approach.

— A team approach with DfRM as a goal. A team may include individuals involved with design, implementation, support, and training.

— Gather maintenance data and develop into Reliability, Availability, and Maintainability (RAM) models. Maintenance data may be gathered from the maintenance technician's field data collection system, customer surveys, and warranty information. The data are then developed into information that supports decisions.

— Identify and develop maintenance concepts using information from the RAM models. Some pipeline operators may dictate the maintenance concept they use. In other cases, the manufacturer may develop the maintenance concept or the product development team may generate the maintenance concepts. The selected maintenance concept is an important design constraint.

— Design product using selected maintenance concepts. The design process begins using a systems approach and a variety of design tools, design rules, and approaches. At this stage, flexibility is great and design change costs are low.

— Design, analyze, test, and improve/optimize the LDS. Based on the results of analysis and test (a prototype of portions of the product or even the entire system may be built), the design evolves and maintenance concepts are reviewed and revised. At this stage, flexibility decreases and design change costs rise.

— Engineering finalizes the design and implements the DfRM system. At this point, flexibility to modify the product maintenance features is low and the change costs are high.

— Collect field maintenance data and develop information. Collect product field data in the form of customer feedback, warranty information, surveys, and service work. The information derived from these data may be used to evaluate the performance of the product in the field and in designing and/ implementing new maintenance systems. The results of ongoing meter proving may be a used to evaluate condition of the meters.

— Make field improvements as required by safety, economics, and other factors. Initial field performance may be lower than anticipated and there may be additional changes to the design, procedures, or maintenance concept. At this point, modifying the product is very difficult and expensive. Only those changes dictated by customer acceptance or safety or that are economically attractive may be made.

— DfRM process repeats with next generation product. Based on information generated from the field data, the design for maintainability process is repeated for the next generation product. Design rules may be revised, new tools developed, and design approaches validated or revised.

Redundancy for component failure and maintenance may be provided. This may be hardware redundancy for individual components, backup systems, communication channels, or alternative operating procedures. For example, redundant sensors may be made active while the primary is offline for calibration, maintenance, or replacement. The pipeline operator may evaluate the process by which a redundant system or component becomes active. An automatic cut-over to the backup/redundant system or component is one approach. Use of an alternate operating procedure is another approach.

Field instrumentation should be appropriate for the task and design specifications should provide for the required accuracy. Program policies may specify design requirements of instrumentation. As an example, measurement accuracy and repeatability should be specified to meet appropriate targets for leak detection. It is important to design so the components selected are able to provide accurate measurement under all operating conditions and not just when conditions are ideal. For example, some instruments may not work well when a product batch changes. In this case, a meter that cannot accommodate a batch change would be the wrong selection for a batched pipeline.

Maintainability analysis may be utilized to assess the design for ease of maintenance and collaborate with Human Factors Engineering (HFE) SMEs (if they are available) to assess impacts to support staff operations (maintainers) of the LDSs. Engage with all technicians and engineers supporting the LDS to help craft the maintenance strategy and discuss levels of repair and sparing. Look for opportunities to gather maintainability and testability data during all test phases. Look at Fault Detection and Fault Isolation (FD/FI) coverage and impact on repair timelines. Address software maintenance activity in the field as patches, upgrades, and new software revisions are deployed. Be aware that the ability to maintain the software depends on the maintainer's software and IT skill set and on the capability built into the maintenance facility for software performance monitoring tools. A complete maintenance picture includes defining scheduled maintenance tasks (preventive maintenance) and assessing impacts to LDS availability.

12.5 Maintenance Tracking and Scheduling

The operator should integrate maintenance of the leak detection components into a pipeline operator's MMS or CMMS system or similar system to provide for automation of maintenance activity and failure tracking. A CMMS may include the ability to capture reliability metrics such as Mean Time Between Failure (MTBF). These reliability metrics may then be evaluated to determine if additional action is needed to prevent future LDS component failures that would adversely affect leak detection performance. Reliability metrics may be tracked for both communications and processing unit components (e.g. communication losses to field instruments, or net server up time) and may be integrated with the pipeline operator's Level 4 KPIs (which are discussed in Section 13).

CMMS may include ties to a MOC process. When a MOC process is not linked to the maintenance system, then some type of MOC process should be applied.

The CMMS may track time for repairs and the condition before calibration or repair and what repairs are made. The CMMS may include details such as the end of life estimate for replacement.

The operator should provide for scheduled (i.e. routine calibration) and make allowance for unscheduled (i.e. break-fix) activity and the device criticality ranking. The schedule may be time based or based on some other criteria, for example: proving may be performed for each batch. Some components of a LDS are more critical than others. Each pipeline operator may create a ranking system (i.e. through RCM) for each component and specify the impact of a component failure and provide clear policies for actions to take when device is compromised. Criticality is determined by the effect the loss of the device (or the associated loss due to for example inaccuracy) has on the leak detection technique. For example, complete loss of a flow meter in a volume balance LDS may cause a total loss of function of the leak detection technique, while varying accuracy of a flow meter may reduce the sensitivity of the technique but may not make it inoperative.

By tracking reliability metrics for field instruments, communications, and processing units and having an associated criticality ranking system, a strategic plan may be implemented to address issues and drive for a more reliable LDS. These reliability metrics may be linked to the pipeline operator's performance metrics, KPIs, and targets.

Additional maintenance and reliability should include software maintenance (e.g. patches, revision, updates, code fixes, etc.). Clear policies and procedures should be in place to ensure that the required maintenance is properly communicated to appropriate stakeholders as to duration, impact, and effectiveness. Potential risks should be identified and communicated.

13 Overall Performance Evaluation of the LDP

13.1 Purpose and KPIs

Overall LDP performance evaluation focuses attention on the LDP management program results that may demonstrate improved safety and risk reduction has been attained The measures provide an indication of effectiveness, but are not absolute. Performance measure evaluation and trending may also lead to recognition of unexpected results that may include the recognition of threats not previously identified. All valid performance measures are simple, measurable, attainable, relevant, and permit timely evaluations. Proper selection and evaluation of performance measures is an essential activity in determining integrity management program effectiveness

The overall performance evaluation of the pipeline operator's LDP should capture and evaluate noteworthy results of operation of the LDP, benchmark company performance, and report to management on an annual basis the results of the overall performance monitoring. The overall performance evaluation should be performed using both an internal review and an external review by utilizing both internal information and external information.

The overall performance for the LDP should be measured with KPIs. The pipeline operator should establish KPIs (e.g. improper attribution of non-leak alarms) that may be used for this purpose. It may be difficult to compare performance to targets so relative values may be measured using historical information (i.e. is the performance improving or degrading from average values).

13.2 Internal Review

Internally, the overall performance evaluation looks at LDP information through the lens of API 1175. Operators should establish a comprehensive internal data repository or enhance existing data repositories to facilitate the data collection and analysis process.

The results of the internal review may include:

— identified gaps in strategy;

— performance metrics evaluation results;

— assessment of the strength of the culture;

— changes to roles and responsibilities;

— new activity in the selection process;

— performance monitoring and target changes;

— testing/tuning results;

— feedback from the alarm management process;

— training results;

— notable equipment maintenance activities;

— MOC measures;

— improvements suggested, undertaken, and completed.

13.3 External Review

External comparisons may provide a basis to evaluate the performance of the LDP management program. This may include comparisons with other pipeline operators, industry data sources, and jurisdictional data sources. Benchmarking with other pipeline operators may be useful; however, any performance measure or evaluation derived from such sources should be carefully evaluated to ensure that all comparisons are valid. Audits conducted by outside entities may also provide useful evaluation data.

Useful sources for external review comparisons information may be national or international industry information. The information may be: leak indication reports; regulator's databases (e.g. PHMSA, NEB); industry databases (e.g. API's PPTS), guidance provided by PHMSA and others; activities in the pipeline industry; changes to regulations and any other related sources. The purpose of the external review is to seek benchmarking information and improvement possibilities.

13.4 Key Performance Indicators (KPIs)

Performance measures are selected carefully to ensure that they are reasonable program effectiveness indicators. Change should be monitored so the measures remain effective over time as the plan matures. The time required to obtain sufficient data for analysis may also be considered when selecting performance measures.

The steps to define KPIs for an organization start with a solid understanding of the processes in use by that organization to achieve its objectives. In the LDP, this process starts with an understanding of the leak threats and the leak consequences (see Annex A and API 1160, Table 9) to be able to develop an appropriate strategy, which may then be used to identify appropriate LDS selection and implementation. Overall monitoring of all aspects of an LDP may be realized through defining the correct KPIs and collecting the data consistently, reporting properly, and acting on the data once it is evaluated.

The steps are:

— process review,

— define KPIs and review,

— collect data,

— reporting,

— analysis,

— corrective action.

The review may separate the findings into categories of leading and lagging indicators and further into levels as outlined below (see Figure 3).

Leak detection uses four performance metrics to rate the performance of the LDS. These four metrics (accuracy, sensitivity, reliability, and robustness) are defined and described in API 1130, Annex C. However, these metrics cannot be directly applied to evaluating the overall performance of an LDP. Therefore, KPIs should be defined to monitor the overall effectiveness of the LDP. The first step is that the operator should understand the overall process that is followed in defining, implementing, and executing the LDP. From an understanding of the overall process, KPIs may be identified to understand if the process is functioning in alignment with the overall goals and the specific outcomes desired from the LDP.

Each pipeline operator should develop their own usable list of KPIs. Examples of KPIs are shown in Table 6, Table 7, Table 8, and Table 9.

The KPIs may be analyzed to determine if the pipeline operator is improving in this critical area.

The strategy may have set performance requirements for the overall LDP and KPIs are used to measure progress against those requirements. KPIs to measure the overall LDP are likely to be different than those used in monitoring individual pipelines.

13.5 Periodic Reporting

Well-designed KPIs are extremely useful measures for the pipeline operator’s personnel to understand how well the people, processes, and LDSs are functioning to achieve the overall objectives that have been approved as part of the corporate leak detection strategy. As such, there should be a reporting of the most significant KPIs to the pipeline operator’s management on an annual basis. The management review should include documentation of the fact that the review occurred.

Another purpose served by KPIs is the ability to benchmark a single pipeline operator's performance against a larger group in order to compare the pipeline operator's performance to others executing the same type of process. To achieve this type of benchmarking ability, several KPIs are identified in Table 6 (Level 1) and Table 7 (Level 2) that should be collected to allow for inter-company comparison.

13.6 Leading and Lagging Indicators

13.6.1 Review Process

There are several concepts that should be understood prior to implementing a set of KPIs to measure the success of an LDP. Of particular importance is the difference between leading and lagging indicators. Lagging indicators are "after the fact" measures, whereas leading indicators will help companies take a more proactive stance in managing their LDP.

13.6.2 Lagging Indicators

Lagging indicators are those KPIs that measure an event after it has already occurred. This view indicates the number of failures or events that have taken place in a given time period, but do not necessarily assist in determining the underlying causal factor.

An example of a lagging indicator is a measure of how many pipeline leaks were alarmed by an LDS in a given time period, given that the LDS was designed to detect a leak of that size.

13.6.3 Leading Indicators

Leading indicators are used to predict a future outcome of a process. These are valuable to define, measure, and evaluate to determine if a process is working correctly. The assumption is that a correctly working subprocess may lead to improved results in the overall process being implemented.

An example of a leading indicator is a measure of how consistently Pipeline Controllers are trained in the use, understanding, and operation of the LDSs implemented within a Control Center. The underlying assumption is that consistently well-trained Pipeline Controllers would be better able to understand the data being presented to them and respond in a more appropriate manner. Therefore, a KPI to reflect this may be the percentage of Pipeline Controllers who are trained on the concepts of the LDSs on an annual basis.

The framework, as outlined in OGP 456 and API 754, may be used as a basis to structure leading and lagging indicators into a useful tool. KPIs may be categorized into levels to differentiate the ones that require company-wide attention from those that are useful to personnel who manage or implement specific LDP subprocesses.

Level 1 and Level 2 KPIs are generally lagging KPIs and should be internally collected to allow industry-wide benchmarking of overall LDP performance. The recommendation in this RP is that Level 1 and Level 2 KPIs should be established as defined in Tables 6 and 7. Levels 3 (Table 8) and 4 (Table 9) are only internally collected and reported.

This data collection and reporting may facilitate individual corporate performance measures, industry performance measures and a benchmarking measure for corporations to use in measuring their performance against industry averages.

The difference between Level 1 and Level 2 KPIs (see Tables 6 and 7, respectively) is based on whether or not the incident meets the PHMSA definition of a significant incident. Level 1 KPIs are LOC events that are PHMSA-reportable significant incidents. Level 2 KPIs are the same measures, but are collected when the LOC is non-reportable or PHMSA-reportable but is not classified as significant. Level 2 events are still very serious and should be measured to be consistently evaluated.

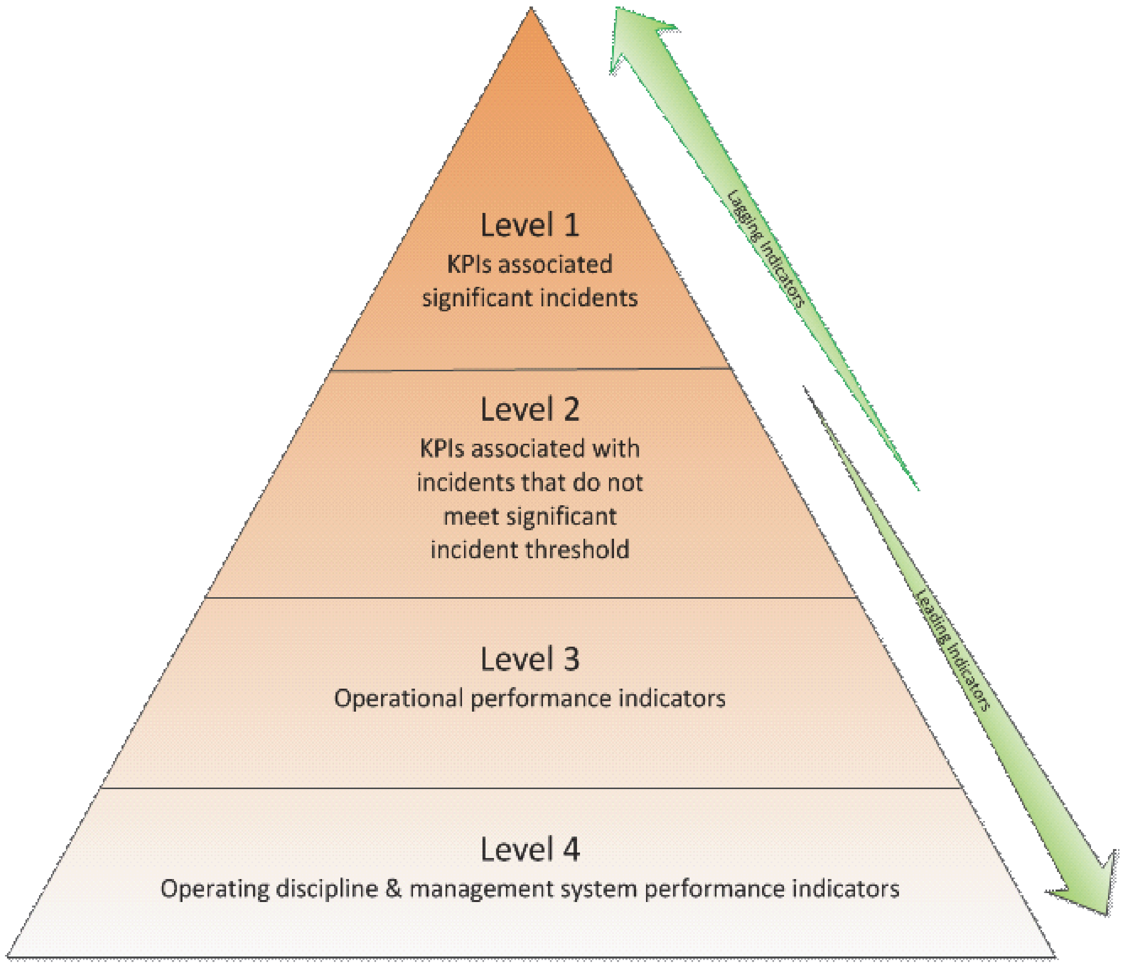

Figure 3—Levels of Process Safety (similar to API RP 754)

Table 6—Level 1 KPIs

Level 1—*Outcome focused, event is significant and is reportable to PHMSA*	
Leading KPIs	**Lagging KPIs**
	Barrels per leak where continuous LD method was designed to identify leak
	What LD methods detected the leak
	Estimated total cleanup costs to pipeline operator resulting from LOC where a continuous LD method was designed to identify the leak
	Time between LOC and leak alarm, where continuous LD method was designed to identify leak or notifications
	Pipeline Controller's shutdown percentage in response to leak alarms or notifications
	Number of large leaks where continuous LD method alarmed, where continuous LD method was designed to identify leak
	Percentage error in identifying the leak location by the LDS, where continuous LD method was designed to identify leak
	Number of false negative leak alarms where the continuous LD method was designed to identify the leak

Table 7—Level 2 KPIs

Level 2—*Outcome focused, non-reportable or PHMSA reportable but is not classified as significant*	
Leading KPIs	**Lagging KPIs**
The same KPIs as are listed in Table 6	

Level 1 and Level 2 KPIs in this document are outcome focused and are directly tied to some measure of each pipeline leak. Examples include the number of leaks that were detected by the leak detection system, amount of product leaked where the LDS was designed to detect a leak of that size, and the cost to the pipeline operator from the leak where the LDS was designed to detect a leak of that size. These measures may help answer the question of whether LDSs are effective in detecting and minimizing the amount of product that leaks from the pipeline.

Level 3 KPIs (see Table 8) in this document are more operationally focused and emphasize the challenges to the particular LDS(s) implemented by the pipeline operator. These KPIs may help to understand how well LDSs are performing once implemented in a pipeline operator's environment. The underlying assumption is that if these KPIs indicate a problem in the proper functioning of the LDS, it may not be able to promptly and reliably alert the Pipeline Controller to a leak. Examples include the number of non-leak alarms generated from the LDS.

Level 4 KPIs (see Table 9) are generally leading KPIs and are more focused on measuring the quality of the processes used within the LDP. They may be useful to determine whether or not a defined process is being executed correctly. These KPIs are more specific to the individual LDP established in various pipeline operators and therefore are expected to be unique between pipeline operators. Suggestions are included below in the Level 3 and Level 4 KPI section, but industry-wide reporting is not feasible due to the tailoring of these KPIs for each pipeline operator's individual LDP.

Level 3 and Level 4 events have the potential to lead to Level 1 or 2 events.

Table 8—Level 3 KPIs

Level 3—*Pipeline operator internal measures, leading indicators, operationally focused KPIs*	
Leading KPIs	**Lagging KPIs**
Percentage of non-leak leak alarms that are analyzed, rationalized, addressed, and documented by the leak detection analyst in a given time period	
Number of non-leak leak alarms generated from the LDS	
Amount of time that an LDS is in alarm state during operation	
Percentage of total pipeline covered by a continuously monitored LDS	
Percentage of total pipeline where actual LDS performance meets design criteria	
Percentage of time that the LDS is available during operations (uptime of the LDS)	
Number of tests conducted on an LDS in a given year	
Percentage of LDSs with non-tuned thresholds	
Percentage of LDSs that undergo a reviews of alarms or notifications in each year	
Percentage of leak alarms where the cause of the alarms or notifications is identified, i.e. communication, metering, instrumentation, SCADA, etc.	
Number of times per year that an LDS has had tuning changes in threshold limits	

Table 9—Level 4 KPIs

Level 4—*Pipeline operator internal measures, leading indicators*	
Leading KPIs	**Lagging KPIs**
Percentage of Pipeline Controllers who are trained on the concepts of the LDS on an annual basis	
Whether leak causes reviewed on an annual basis and new information included in updating the pipeline operator leak detection strategy	
Average time to correct an instrument malfunction that impacts an operational LDS	
Percentage of MOC items that impact the Pipeline Controller LDP training	
Leak detection staffing levels per mile of pipeline in operation	
Percentage of LDSs where alarm settings are reviewed and confirmed on an annual basis	

13.6.4 Dual Assurance

Dual assurance is a concept whereby a leading indicator at a lower level is matched with a lagging indicator at a higher level. The goal is to predict where performance of a process is clearly and directly tied to performance at a higher-level objective. An example of this relationship in an LDP would be a leading KPI to measure the percentage of non-leak alarms that are analyzed, rationalized, addressed, and documented by the leak detection analyst in a given time period compared to a lagging indicator where a Pipeline Controller's shutdown percentage in response to leak alarms is measured. The assumption being that a more careful, thorough evaluation of non-leak alarms by a leak detection analyst and tuning of the LDS would result in a lower number of unwarranted shutdown situations. If the pipeline operator is able to properly address non-leak alarms in the LDS, only true leak alarms are indicated to the Pipeline Controller.

13.6.5 Data Normalization

Data normalization refers to the effort to make data comparable (for example, over time or between different entities). Normalization is necessary to compare data between various operators. For normalization to work, it is necessary to understand the basis of the data and to have a common definition for the items. For example, if the definition of a leak is different between operators, then it is not possible to compare their KPIs. In this RP, the leak definition in line with the *CFR* is recommended.

14 Management of Change (MOC)

Pipeline operators shall apply their formal MOC process as required in 49 *CFR* Part 195.446(f). The MOC process should include the requirements of API 1167, Section 11 and API 1160, Section 13. The requirements of the two API documents may be tailored to accommodate the unique aspects of LDSs.

Changes to any aspects of LDSs (technical, physical, procedural, and organizational) should follow the pipeline operator's formal MOC process.

15 Improvement Process

15.1 Overview of Improvement Process

An ongoing improvement process is an important part of the LDP and should align with the pipeline operator's strategy. Suggestions for the LDP improvement process are provided in this section. The improvement process itself should be "evergreen", to be updated and improved on a regular basis. KPIs that are specific to the improvement process should be tracked and reviewed for progress. The improvement process should be periodically performed to define improvements in the LDP, plan for and track to completion improvements that are needed to meet existing LDP goals, or to satisfy new goals.

Improvement of the pipeline operator's LDP and strategy involves two aspects: identifying and defining issues for improvement and initiating and monitoring the improvement process for the identified issues. The results of improvements undertaken and/or the improvements underway should be reported, for example, in an annual report or as a part of a pipeline operator's IMP annual report. Resources for the work should be identified and obtained. Per requirements of 49 *CFR* Part 195, pipeline operators are required to budget, schedule, and track improvement projects to completion. A pipeline operator should develop a timeframe for when they want to complete these improvement projects.

15.2 Identifying and Defining Opportunities

Improvement issues and suggested improvements should be identified during the management of the LDP. The operator should develop a plan or process to capture improvement suggestions so it they may be passed to those who manage the improvement process. The issues identified should be described by the party who identifies the concern and the issue should be passed into the improvement process. It may be possible to establish metrics and KPIs that may be used in evaluating the continual improvement possibilities.

The improvement process may start with the following information.

— Suggestions or requirements for improvement from all areas of the LDP.

— Suggestions or requirements from Section 13, Overall Performance Evaluation, of the Pipeline operator's LDP.

— Any new continual improvement targets or information that may be used to set new continual improvement targets (benchmarking, etc.).

— Applicable standards and industry best practices.

— Details of previously identified actions for improvement with their status (determine if previous actions are being properly executed. If not, adjustments should be made to ensure execution of the actions).

Possible specific items for inclusion may be as follows.

— Information provided in the overall LDP evaluation and covering leading and lagging indicators (Levels 1 through 4).

— Lessons learned from the review of three to five years of industry leaks or leak alarms (where these exist).

— Issues encountered in the maintenance programs and analysis (i.e. worst actor/bad actor, updates to the FMEA).

— Gaps identified by KPI evaluation, event analysis, Root Cause Analysis (RCA), where parts of the LDP failed.

— Gaps identified in the strategy, selection, or the work of any other section outlined in the LDP RP.

— Performance monitoring results as recommended in the performance-related sections in the RP.

— Apparent trends that indicate issues with the pipeline operator's leak detection capability or effectiveness.

— Pipeline operator performance comparisons or benchmarks.

— Results from examination of software upgrades.

- New detection techniques and evolution of the state-of-the-art that offer features that promise improvements to the LDP or do not have common points of failure with existing LDSs.
- Engineering studies (e.g. API 1149 calculations) that indicate where other instruments or more measurement may be beneficial.
- Information obtained at conferences or from conference papers, R&D programs, results of R&D tests, etc. that may be applicable.
- Results of tests that indicate disconnect between expected and actual performance.
- Information on frequency of threshold adjustments.
- Information about new shipping routes or products.
- Assessment of where the strategy is not being fulfilled (gaps) (i.e. adding instrumentation in one part of the facilities, instituting within whole pipeline system).
- Issues about unclear roles and responsibilities that should be upgraded.
- Issues about unclear Control Center recognition and response or CRM procedures.
- Changes related to updated risk analysis, meaning the risk has changed.
- Training concerns.
- Perceived level of interest in the LDP within the organization and things being done to retain interest in the LDP.
- Changes to or evolution of regulations.
- Issues with public perception of the pipeline operator's system.
- Issues identified or indicated in the integrity management plan.

15.3 Initiating and Monitoring the Improvement Process

The improvement process should include a review of the thoroughness of the collected information along with a checklist to verify that key components of the LDP are covered in the process. During this initial process of planning, all of the suggestions, requirements, and new continual improvement targets should be reviewed. The review may decide for each item what recommended actions should take place. Actions, for example, may be:

- defining and recommending a project to make the improvement;
- performing maintenance to make the improvement;
- making changes or adjustments to make the improvement;
- other efforts such as evaluating, planning, etc., that lead to improvement.

The process should be a formal review that is documented and retained. Documentation should include the inputs to the process along with the recommended actions. Issues should be fully described. Actions should be clearly defined, measurable, specific, attainable, and realistic.

Timeframes should be determined and resources should be assigned for various types of projects:

— For improvement projects, the issue should be fully investigated, described, and prioritized. A project is then evaluated and recommended or not recommended for funding. Any required projects (compliance, etc.) are budgeted for, scheduled, project duration is determined, and a project manager assigned where the project is tracked to completion. All improvement projects are appropriately defined, prioritized, risk ranked, and budgeted as required by the pipeline operator's project practices for recommended projects. The pipeline operator's project management practices should be applied to manage the project.

— For maintenance improvements, the activity should be performed with verification of the outcome. The MMS or CMMS may be used as appropriate to track the outcome of the maintenance activity.

— For a change or adjustment improvement, the work should be fully documented.

— For other types of improvement efforts, if the action is some evaluation, planning effort, and/or investigation, then the effort should be fully documented and any further steps defined and planned. Any of the improvement types may be coordinated with and use the pipeline operator's MOC process as appropriate.

Key stakeholders should be included as appropriate.

After reviewing the inputs and defining actions, a simple checklist may be used to review the LDP. The checklist may be used as a check to assure that no areas are being missed. The result of checklist review would be that key areas have been checked and accounted for and that stakeholders are included and are in agreement with the outcome of the review. The checklist may be a simple review of the LDP areas as forth mentioned in this RP, examples are as follows.

— Was culture and strategy part of the review?

— Were inputs included in the review?

— Were KPIs and targets part of the review?

— Were continual improvement targets identified?

— Were actions identified?

— Were last year's actions completed?

The result of the improvement process is a better LDP. Efforts from the improvement planning and process should be projects, changes, or other efforts to improve various facets of the LDP. These efforts would be managed and tracked by the pipeline operator's current processes for project management and tracking, maintenance planning and tracking, or management of change. KPIs may be kept and reviewed for progress. Candidate KPIs are discussed in the section entitled Performance Targets, Metrics, and KPIs. At a minimum, the outcome of these efforts should be reviewed in the next cycle of improvement process and the appropriate adjustments made.

Annex A
(informative)

Risk Assessment

A.1 General

The risk assessment may include consequences, likelihood/threats, frequency, and other risk factors associated with leak detection and identified in the IMP.

A.2 Consequence Analysis

A consequence analysis (comparing mitigated and unmitigated consequences) of a hazardous liquid LOC may include the factors outlined in Table A.1.

Table A.1—Consequence Factors

Pipeline profile
Terrain surrounding the pipeline
Flow path for leaked hazardous liquid
Waterways, streams, ditches, and subsidence areas that may act as a conduit to a high-risk area
Hospitals, care facilities, schools, and retirement homes
Population density
Places where people congregate
Commercial navigable waterways
Drainage systems or conduits
Land usage (farm field, urban)
Fish hatcheries
Fluid characteristics and leak potential/volume
Detection time
Possible size of leaks
Dispersion path of any flammable vapors
Dynamic and static leak volume
Distance between isolation points or valves
Cost of cleanup
Health, Safety, and Environment (HSE) factors
Existing LDP, principles, methods, and techniques

Table A.1—Consequence Factors (Continued)

Number of primary and complementary LDSs and their capabilities
Response time at all levels
Response capability in field
Pipeline accessibility
Type of valves: motorized EFRDs, hand-operated valves, remote control valves, automatic control valves
Time required to isolate the pipeline segment or contain the hazardous liquid leak
Pipeline system hydraulics and operation
Emergency response plans
LOC scenarios
Pristine areas that are SAs

The pipeline operator should define the response time and the steps. It would typically include the total time of multiple steps; for example: time to detect, time to analyze and verify, time to shut down and isolate, and perhaps time to get response people to the leak site.

A.3 Likelihood/Threat Analysis

The likelihood of different leak rates occurring depends on the likelihood of initiating events, meaning how likely and perhaps how often they occur. The primary possible causes or threats of a pipeline failure that results in a leak are outlined in Table A.2.

Table A.2—Likelihood Factors

History of leaks on the pipeline
Corrosion
Equipment failures associated with pipeline appurtenances
Incorrect operations/human error (e.g. exceeding MOP MAOP)
External damage caused by pipeline operator personnel, contractor, third party, etc.
Manufacturing defects
Subsidence, soil washout possibilities
Construction defects
Weather or outside forces
The deliberate action of outside agents for either commercial reasons (theft) or political/motivational reasons (terrorism)
Other/unknown
Other likelihood factors
Potential natural forces inherent in the area: flood zones, earthquakes, slide areas
Pipeline characteristics
Throughput
Physical support of the segment such as by a cable suspension bridge

Table A.2—Likelihood Factors (Continued)

Non-standard or other than recognized industry practice on pipeline installation
Pipeline integrity issues
Results from previous testing/inspection
Known corrosion/condition of pipeline
Cathodic protection history
Type and quality of pipe coating
Age of pipe
Type, growth rate, and size of discovered defects/anomalies
Frequency of inspection/testing (or time since last inspection)
Internal testing
Pressure testing
External inspection
Operational factors
Stress levels in the pipeline
Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure
Quality of MOP estimates
Intermittent column separation

A.4 Preventative Factors (Protective Layers)

Various preventative factors are outlined in Table A.3.

Table A.3—Preventative Factors

Pipe: wall thickness (WT), cathodic protection (CP), coatings, anomalies/defects, wall-loss rate, corrosion rate
Overpressure protection: maximum operating pressure (MOP) vs. normal operating pressure (NOP) alarms, thermal reliefs, pressure reliefs, safety instrumented systems (SIS), back pressure control system (BPCS), critical alarm panels, pipe casings
Damage prevention: One-calls, third-party prevention, community awareness, 2nd-containments, design for natural disasters, sabotage/vandalism/terrorism prevention
Inspection practices: in-line inspection (ILI), risk analysis, repair programs, CP programs, surveillance, ROW monitoring, public awareness
Corrosion: design, inhibitors, ground beds, rectifiers
Escalation barriers
Bored or open cut under-river installation

A.5 Risk Analysis and Evaluation

Other factors that are likely included in the IMP analysis and may be included in leak detection method selection are outlined in Table A.4.

Table A.4—IMP Factors

Repairs (type and time since completed)
Defects: found, causes, degradation
Pipeline attribute changes
Re-alignment with inspection findings
Results of preventative and mitigative measures (PAMMs)
IMP history

Annex B
(informative)

Developing a List of Selection Criteria

B.1 General

It is necessary to develop a list of selection criteria that satisfy strategy, risk tolerance, and regulatory requirements. There are two key areas: what features are needed and what performance is required. These are discussed below.

B.2 Features Desired

The physical environment in different areas may impact features and a pipeline operator's decision on the best method(s) to implement. There is no reason why such features may not be used for the entire pipeline system, but practicality, risk, and other factors would come into play deciding the best method(s) to use. The physical environment in different areas may impact these features and a pipeline operator's decision on best method(s) to implement them.

The features listed (in no particular order) in Table B.1 are in addition to those outlined in API 1130. In some cases, they may be a near-repeat of API 1130 items or an expansion of the API 1130 list.

Table B.1—LDS Features

Supportable at minimum cost and effort
Utilizes instrumentation currently installed and/or minimizes additional
Internally based or externally based
Suited to existing data acquisition rate
Technology available, industry proven, convenient
Continuous vs. non-continuous nature of the method
Dependent vs. independent methods for each LDS on a pipeline
Commonly used with other pipelines
Alarming ability
Tunable features
Adjustable thresholds
Minimal complexity of training required for the users
Maintenance and support activities available within pipeline operator
Fits evergreen activities within the pipeline operator
Diagnostics tools are available in the method (i.e. not a black box)
Fits with operability and business continuity planning
Implementation ease
Growth potential for the future
Additional desirable features that may be useful (e.g. trend charts)
Lifecycle maintainability (includes all costs)
Pipeline operator's experience with the application
Testability (there is a concern about testing some externally based methods) in service

Table B.1—LDS Features (Continued)

Testable while being implemented and deployed
May be enhanced from basic configuration (e.g. infrared sensors added to visual methods)
Upgradable (more features may be added)
Minimization of technological complexity
Covers all pipeline physical characteristics
May operate with elevation profile and profile accuracy
Suitable for ambient temperatures
Low frequency of configuration changes
Suitable for pipeline network complexity
May operate with power/infrastructure available at sites
Suitable for burial depth of pipeline
Works with soil characteristics
Able to operate with weather patterns along pipeline
Operates with all pipe equipment: valves, stations, segments, stub lines, dead legs
May accommodate physical properties of hazardous liquid
Works with SCADA system:
Specifically for a RTTM:
Handles pressure/temperature transients
Handles column separation/slack line operation
Fully covers throughput ranges from maximum rate to shutdown:
Items that are part of the pipeline operational characteristics:
Handles frequency of startup/shutdown (strong transient events)
Handles imposed flow transients
Able to handle flow direction changes:
Other factors related to the feasibility of the method:
Cost
Procurement ease
Installation ease
Maintenance required
Additional staffing requirements
External support requirements

Table B.1—LDS Features (Continued)

Works with existing infrastructure (both back office and field)
May use current measurement and instrumentation
Power additions required
Personnel knowledge base needed:
Other selection factors. These are listed in no particular order:
Whether the various LDSs have a single common point of failure (i.e. part of independent or dependent)
Whether there is a sufficient user base to ensure that the vendor is long term viable and stable
Amount of training required for the configuration staff and users
Whether a risk-based evaluation can be used
For a non-continuous or periodic LDS, the minimum frequency and whether that frequency appropriate for the particular pipeline
Whether the LDS has suitable diagnostic tools not only for alarm analysis but also to evaluate if it is operating at 100% of capabilities
Amount of maintenance required to ensure the LDS remains operable
Display capabilities of the LDSs
Whether the LDS is testable with the existing resources
Types of tools or methods needed to confirm the cause of the alarm
Whether the LDS can be easily tested during selection evaluation
Offline capability for training (provided as standard with software)
Whether the LDS can be implemented in a simple configuration, then upgraded with additional incorporated features later
Whether API 1149 calculations can be applied to estimate the capabilities of the LDS
Types of leak validation methods that should be used to evaluate alarms (e.g. on-site inspections, use of experts, pressure testing)
Applicability to the full range of the operator's pipelines and products
How a particular leak detection methodology may complement another methodology
Existence of other potential benefits, such as communication possible through fiber optical cables
Whether instruments should be relocated for optimal LDS performance or the existing sensors as situated are suitable for the LDS

B.3 Performance Desired

Evaluations for performance required/desired and for selecting the leak detection principles, methods and techniques that are used in the pipeline operator's LDP may require a comparative evaluation of the performance wanted and the performance possible. The performance may be quantified by use of metrics and related KPIs.

For the purposes of understanding performance, the aspects of an LDP may be categorized as monitoring, surveillance, or verification. Leak detection monitoring is performed on a continual basis with the intent of detecting operational or physical changes of a pipeline segment that may indicate that a leak has occurred. In order to classify as monitoring, a component should be actively "watching" for the formation of a leak, typically using real-time data or other means.

Examples of leak detection monitoring are shown in Table B.2.

Table B.2—Types of Leak Monitoring

One-call notifications
Public awareness capabilities
Rupture monitoring LDSs
Line patrol and surveillance leak monitoring
Pressure and flow monitoring
CPM LDSs
Externally based real-time LDSs
Real-time video feed that is continuously being analyzed
Visual detection by company employees or contractors

The likelihood of the success of the monitoring is a combination of the reliability and robustness. Leak detection surveillance examines the pipeline on a periodic basis in order to determine if a leak exists.

Examples of leak detection surveillance are shown in Table B.3.

Table B.3—Types of Surveillance

Leak surveys
Long-term inspections
Aerial surveillance
Foot patrol
Internal pipeline inspections
External pipeline inspections

Leak detection monitoring may be characterized using the following performance indicators of Table B.4.

Table B.4—Monitoring Performance Indicators

Sensitivity of threshold detection
Frequency of monitoring
Reliability of the LDS

There are typically multiple components of an LDP that work with each other to reduce the detection time. During the LDP design and management, it is useful to also evaluate the combined effects of the LDS components.

Annex C
(informative)

Factors Affecting Performance

Figure C.1 represents an example only of the effects of only seven of the various types of uncertainties in the leak detection inputs and illustrates how each affects performance in the various calculation windows that are used in this example LDS for a particular pipeline. In this figure: Scan Rate is the SCADA scan rate; dB loss is the signal-to-noise ratio of the sensing element; Joule–Thomp is the Joule–Thompson effect of the fluid temperature to soil/ambient temperature (typically applies to HVL lines); Man. Adj. is manual adjustment (a threshold factor utilized by the pipeline operator (in bbls); Repeat. is the repeatability of the meter (in bbls); dLP is the change in line pack error (in bbls); and Meter is the meter error (in bbls). It can be seen that in a short leak detection window, the meter accuracy has less impact on performance (less than 10 %0, the dLP has a large impact (about 36 %), the repeatability has a moderate impact (about 28 %), and the Man. Adj. has a moderate impact (about 15 %). For a 24-hour leak detection calculation window, almost all the performance uncertainty is attributable to the meter accuracy.

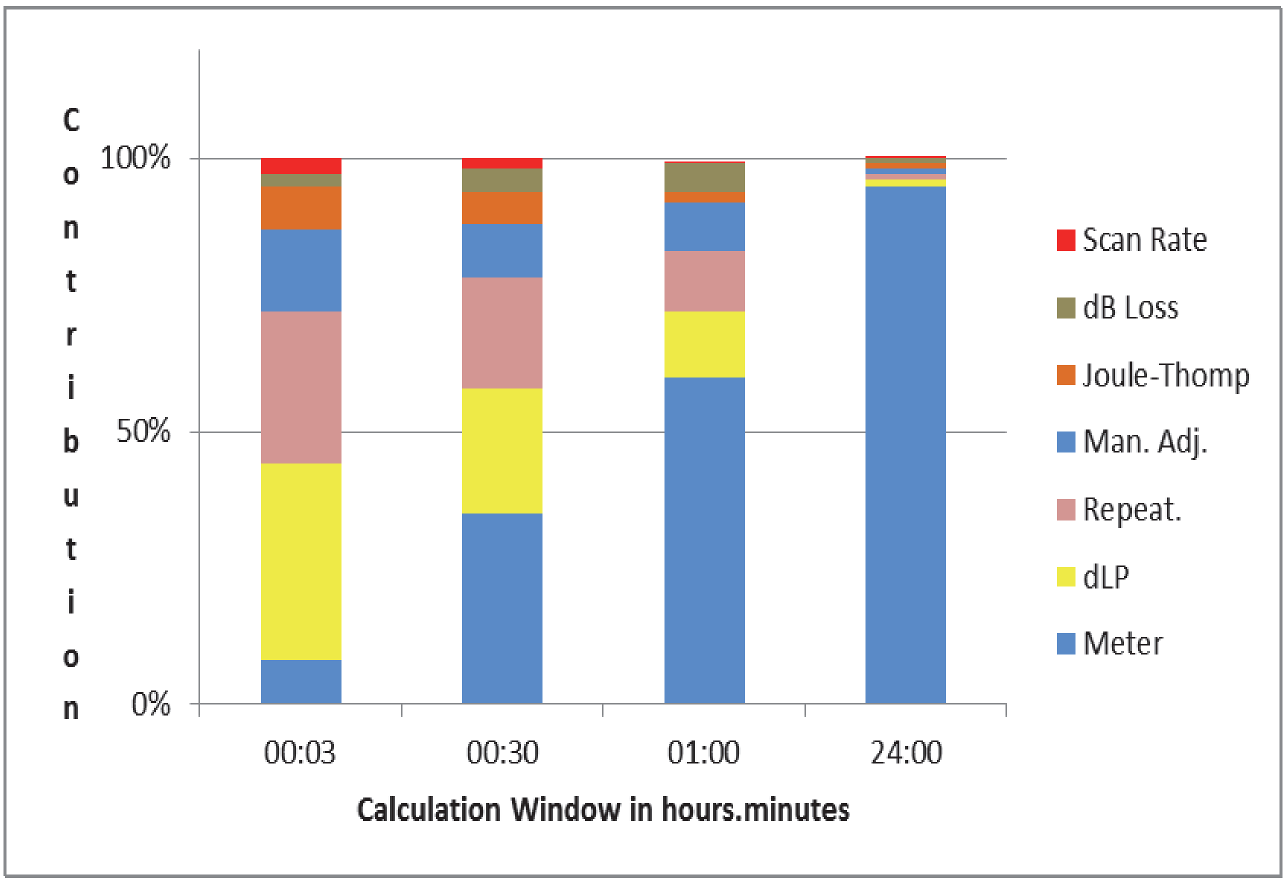

Figure C.1—Effects of Uncertainty Types

Annex D
(informative)

Example of Performance Metrics and Targets

Table D.1 indicates performance metrics and targets that a pipeline operator might apply to a pipeline with a CPM LDS. In the far left column are the leak detection goals. The second column gives the specific metrics or KPIs that are being tracked. Columns 3, 4, and 5 give the performance targets for each metric. There are three performance targets in recognition that the expected performance of a CPM LDS differs in different flow regimes. The last column indicates how the performance target was determined. The possibilities in the example are as follows.

— Observed/historical—the target was determined by analyzing historical data from the LDS during actual operations.

— Observed/testing—the target was determined by analyzing data obtained from a test of the LDS.

— Estimated/API 1149—the target was determined by using uncertainty analysis techniques as detailed in API 1149 to estimate the expected performance of the LDS.

Table D.1—Example Performance Metric/Target Table

Class	KPI	Operation			Notes
		Shut-in	Steady	Transient	
Reliability	Non-leak Alarms	< 1 per month for all operations			Obs./Historical
Sensitivity	Average Alarm Threshold	10 bbl/30 min	100 bbl/30 min	500 bbl/30 min	Obs./Historical
		20 bbl/1 hr	200 bbl/1 hr	1000 bbl/1 hr	Obs./Historical
		40 bbl/2 hrs	400 bbl/2 hrs	4000 bbl/2 hrs	Obs./Historical
Accuracy	Leak Flow Rate	No Target	± 20 bph	Not Determined	Obs/Testing
	Leak Location	No Target	± 5 miles	Not Determined	Obs/Testing
Robustness (Reliability)	Non-leak Alarms During Comm Fail	No Increase			Obs./Historical
Robustness (Sensitivity)	Degradation in Average Alarm Threshold due to Missing Pressure Measurement	100 %	0 %	25 %	Est/API 1149
	Degradation in Average Alarm Threshold due to Missing Flow Measurement	0 %	100 %	100 %	Est/API 1149
Robustness (Accuracy)	Degradation in Leak Flow Rate Accuracy due to Missing Flow Measurement	No Target	No Target	No Target	No Target
	Degradation in Leak Flow Rate Accuracy due to Missing Pressure Measurement	No Target	No Target	No Target	

NOTE The volumetric values listed in this table are for example only and may not have any physical reality to a particular pipeline.

Annex E
(informative)

Roles in the Use of the LDSs

E.1 General

Each pipeline operator may use different names or have different roles for the staff involved in use and support of the LDSs. This annex provides a brief description of roles and a list of common names used by pipeline operators.

E.2 Pipeline Controllers

A Pipeline Controller is a qualified individual whose function is to remotely monitor and control the operations of entire or multiple sections of pipeline systems via a SCADA system from a pipeline Control Room and who has operational authority and accountability for the daily remote operational functions of pipeline systems.

A Pipeline Controller may defer action to others, but is still the primary responsible individual monitoring and detecting abnormal conditions. The Pipeline Controller utilizes automation and tools to determine if a LOC is occurring. The Pipeline Controller communicates with and assists field personnel in response to an investigation of a leak indication. Pipeline Controllers have the authority to shut down any pipeline and/or device when they suspect a leak or there is an abnormal or emergency condition, without prior approval. They are the primary investigators of a leak alarm. They are also the primary recorders of information about leak alarms, although all staff have some role and responsibility for record-keeping and reporting requirements. Other commonly used names used for Pipeline Controllers are shown in Table E.1.

Table E.1—Other Commonly Used Names for Pipeline Controllers

Console Operator	Operator
Dispatcher	Controller

E.3 Leak Detection Analyst

Leak detection analysts analyze data provided by SCADA, leak detection software, and/or personnel to determine if there is a leak and work with the Pipeline Controller. Leak detection analysts provide procedures for pipeline operation as it relates to leak management and provide additional support to Pipeline Controllers who shut down pipelines when there is uncertainty. They also manage the development and maintenance of leak detection operating and maintenance practices and procedures. Other commonly used names for leak detection analysts are shown in Table E.2.

Table E.2—Other Commonly Used Names for Leak Detection Analysts

SMEs	Operation Center Analysts
On-call Support Staff	

E.4 Leak Detection Engineers

Leak detection engineers design and implement LDSs. They work with the Control Center, field operations, and SCADA support on maintenance and updates of the LDS and manage efforts to improve the LDS capabilities, including the evaluation and implementation of value-adding LDS improvements. Leak detection engineers also provide computerized LDSs in accordance with business and regulatory requirements. Other commonly used names for leak detection engineers are shown in Table E.3.

Table E.3—Other Commonly Used Names for Leak Detection Engineers

Hydraulic Engineer	SME
Project Managers	Metering Specialists
Measurement Engineers	Automation and Hydraulic Engineers
Measurements Specialists	Leak Detection Engineers
Leak Detection Architect	Measurement Staff
Measurement and Material Balance Specialists	Capital Project Engineers
Control Engineers	Control Specialists
System Planning Engineers	Engineering Staff
Technical Advisors	

E.5 Control Center Staff

Control Center staff communicate with and assist operational personnel. They work with engineering and SCADA support on maintenance and updates of the LDS and communicate with and assist operational personnel in responding to or investigating a leak, or any pipeline operator personnel who are involved in identifying, detecting, reacting to, or notifying of a leak. Other commonly used names for Control Center staff are shown in Table E.4.

Table E.4—Other Commonly Used Names for Control Center Staff

Supervisors	Shift Supervisors
Leads	Managers/Directors
Control Center or Operation Center Staff	Control Center Management
Control Center Supervisors	Operation Center Analysts
Operations Center Supervisors	Operations Center Specialists
Leak Detection Staff	Leak Detection Analysts
On-call Support Staff	
CPM Engineers	SMEs
Leak Detection Engineers	Asset Integrity Engineers
Surge Analysts	Schedulers
CPM Analysts (including Vendors or Consultants who fill the role or any individual in the decision loop)	

E.6 Field Operations

Field operations include all of the pipeline operator's staff who work at locations along the pipeline. This category may include the following: contractors, third party operators, or any other personnel not described as an operator or full-time personnel who share the same responsibility as the department and position they serve. They may be part of the team that approves pipeline re-start after a leak detection-related shutdown. Other commonly used names for field operations staff are shown in Table E.5.

Table E.5—Other Commonly Used Names for Field Operations Staff

Field Operations and Maintenance Personnel	Operations Technician
Operations Supervisor	Operations Superintendent
Area Manager	Regional Manager
Field Engineers	Electricians
Gaugers	Instrumentation Technicians
Tank Farm Staff	Surveillance Personnel
ROW staff	Internal Emergency Responders

E.7 Information Technology

Information technology provides support to leak detection equipment and some aspects of software such as computer equipment, corporate connections, databases, secure access, etc. Other commonly used names for IT staff are shown in Table E.6.:

Table E.6—Other Commonly Used Names for IT Staff

IT Staff	IT Support

E.8 Leak Detection Trainers

Leak detection trainers ensure that pipeline controllers are appropriately trained and qualified to operate the pipeline including operation of the LDS. They develop and execute an appropriate training and qualification program and ensure that leak detection analysts are appropriately trained and qualified to provide required Pipeline Controller support and required LDP management. Other commonly used names for trainers are shown in Table E.7.

Table E.7—Other Commonly Used Names for Trainers

Leak Detection Trainers	Control Center Trainers

E.9 Management

Management approves the pipeline operator’s leak detection strategy by providing leadership, support, and resources for achieving their organizational goals. It manages the definition and execution of required LDP system maintenance and management practices and procedures to maintain required levels of LDS performance and reliability. Management also defines LDP support personnel requirements and ensures appropriate availability of qualified LDS support personnel, as well as defining business requirements for LDSs. It maintains awareness of regulatory requirements for computerized LDSs and ensures that LDSs are managed to maintain compliance. Other commonly used names for management are shown in Table E.8.

Table E.8—Other Commonly Used Names for Management

Senior Management	Supervisors
Middle Management	

E.10 Leak Detection SCADA Support

Leak detection SCADA support staff implement automation of engineering design and communications to the leak detection hardware/software at operational locations. They work with engineering and operations on some aspects of the maintenance and updates of the LDS. Other commonly used names for leak detection support staff are shown in Table E.9.

Table E.9—Other Commonly Used Names for Leak Detection Support Staff

SCADA Support and Network Engineering Staff	SCADA Analyst
SCADA Engineer	Cyber Security Analyst
SCADA System Support Staff	

E.11 Other Stakeholders

There are many stakeholders for leak detection systems. Table E.10 provides categories and commonly used names for these other stakeholders.

Table E.10—Commonly Used Names for Other Stakeholders

Other Support Staff:
Commercial and Business Development Personnel
Contract or Pipeline Operator Emergency Environmental Staff:
External Responders:
External Emergency Responders
Local Public Safety Officials, First Responders:
The Public:
General Public
ROW Landowners
Third-party Landowners:
Government Agencies or Regulators:
PHMSA
State Regulators
NTSB
Connecting Facilities Staff:
Employees of other Companies Involved in the Injection or Delivery of the Hazardous Liquids Shipped

Annex F
(informative)

Example Training Program

F.1 General

Table F.1 and subsequent text describe an example of an LDP training program, with the exception of Team Training, which is covered in Section 11.

Table F.1—Roles and Level of Training

	Roles											
Level of Training	**Management**	**Control Center**	**Analyst: Leak Detection Staff**	**Engineering: Support Staff**	**IT Group**	**SCADA Support**	**Field Operations: Field Staff**	**Field Operations: ROW Staff**	**Field Operations: Connecting Facilities Staff**	**Public: External Response**	**Public: Government Agencies or Regulators**	**Public: Land Owners/ROW Users**
LDP Operational		X	X									
LDP Technical		X	X	X	X	X						
Internal LD Principles		X	X	X		X	X					
External LD Principles		X	X	X			X	X				
SCADA Deviation Alarms		X	X	X		X						
Pipeline Over/Short Calculations		X	X	X			X					
LDP Awareness		X					X	X	X			
LDP Basics		X					X	X		X	X	X
LDP Regulations/Standards	X	X	X	X								
LDP Strategy & Culture	X	X	X	X	X	X	X	X			X	
LDP Management	X	X	X									

F.2 Level of Training

F.2.1 General

Each level of training may consist of a set of modules appropriate to the role of the individual. For example, Control Center staff should have a basic understanding of internally based LD technique architecture but do not need the same depth of training on that subject as do leak detection staff. Recommended training content is in the following sections.

F.2.2 LDP Operational Training

LDP operational training is primarily for Pipeline Controllers and Control Center staff who directly respond to LDP alarms or indicators.

However, analysts from the leak detection staff should also understand the operational response to alarms or leak indicators. Content factors are as follows (also see API 1130, Section 6.5, Pipeline Controller Training and Retraining).

— Control Center procedures for leak detection and response. Pipeline Controller-specific procedures for response to leak detection alarms.

— Hydraulics. Physical principles of hydraulics and concepts of all pipeline operating regimes as they relate to LD techniques, including, for example, the variances of hydraulic pressure due to elevation profiles, batches of differing density (fluid properties), temperature effects, and effects due to DRA, column separation, scrapers, and ILI tools. In particular, the Pipeline Controller should be trained in the basic relationship of pressure and temperature during shut-in conditions. These may include an understanding of pressure tests and hydro tests.

— Alarming/Performance. All LD technique alarming and indicators of LD technique performance. Pipeline Controllers should be trained in definitions and the proper recognition and response to all LDS alarms. Such alarms include indications of leaks and of the health of the LDS.

— Data Presentation. Recognize of all LDS notifications or alarms and how to research the cause of the alarms (e.g. data failure, irregular operating condition, or possible leak). Other specifics regarding data presentation may be referred to in API 1165.

— Instrument Failure. Impact of an instrument failure on any LDS where the instrument is used.

— Validating LDS Alarms. The operator should undertake an evaluation of the LDS and operating conditions for validating or explaining the cause of an alarm. Pipeline Controllers should be capable of investigating all alarms, including non-leak alarms, and properly attributing them with assistance from LD staff if needed. Non-leak alarm attribution should be a defined set of causes, for example, data failure, irregular operating condition, or LDS error.

— Line-pack Change. Recognize hydraulic pressure changes due to varying line-pack, including column separation line conditions and their impact on the LDS. A fundamental element in the spectrum of inventory control is the calculation of mass or the comparison of barrels in vs. barrels out. This training would include the ability to recognize the compressibility behavior of the hazardous liquids that are transported.

— Trending. Trending analysis of pipeline variables from SCADA and the LDS.

— LDS Operation. Understand of all LDSs operations and the concept/theory of their operation, including statistical analysis. Interpret alarms correctly and in a timely manner or work with internal or external resources to evaluate the alarm.

— Abnormal Functions. Recognize and react to the abnormal function of an LDS as well as the abnormal function of the SCADA system. Recognize LDS malfunction and degradation due to field equipment or SCADA failure. Understand all failure modes identified through FMEA, RCM analysis, or other techniques and how to recognize and respond to them. For example, if an internally based LDS becomes non-functional or severely degraded due to field equipment or SCADA failure, the Pipeline Controller should be trained to employ other LDSs or methods to compensate for the loss or degradation of the internally based method.

— Other Leak Detection Techniques. How to employ the results of other LDSs such as reports from field or ROW staff, third-party reports, SCADA deviation alarms, externally based methods, etc., so that an internally based method is not the only means of detecting leaks.

— Basic SCADA / LDS Architecture, Including Networks and Peripheral Devices. Pipeline Controllers should have a basic understanding of the devices required for the LDS to receive data to function properly including PLCs, switches, routers, network routes, and redundancy of such devices.

— Leak detection staff should understand the limitations of the available LDSs.

F.2.3 LDP Technical Training

LDP technical training is primarily for analysts from the leak detection staff who analyze alarms and maintain internally based LD platforms. Control Center staff should be exposed to this training as well to assist them with initial analysis of alarms. Sections of this training are applicable to Engineering, IT, and SCADA support staff. Content may include:

— details of algorithms and configurations of all LDSs;

— details of computer equipment, including redundancy (architecture and peripherals) of all LDSs;

— details of inhibits, degradation;

— interpretation of in-line inspection (ILI) tool data;

— interpretation of pressure test and hydro test data.

F.2.4 Internally Based LDS Methods Training

Internally based LDS methods training is to familiarize the Control Center staff, analysts, and support staff with the inputs to internally based LDs methods. Content may include:

— basics of internally based LDS method tools and techniques;

— types of equipment used in internally based LDS methods, equipment characteristics, and maintenance effects on internally based LDS methods, including field instrumentation;

— engineering design of internally based LDS methods.

F.2.5 Externally Based LDS Method Training

Externally based LDS method training is for the Control Center staff and analysts who analyze alarms and for engineering support staff and field operations staff tasked with maintaining these LDSs on the pipelines. Content may include:

— types of LDSs installed and how they function;

— visualization of the LDS to the Control Center and locally (leak alarms, leak locations, and health alarms, for example);

— locations;

— sensitivity and interpretation of alarms;

— failure modes;

— pipeline operator's procedures for aerial and ground surveillance and reporting results.

F.2.6 SCADA Deviation Alarm Training

SCADA deviation alarm training is for both Control Center staff and other staff who analyze deviation alarms to understand their significance and the algorithms behind them. Content may include the following.

— Typically, a SCADA system-generated event alerts the Pipeline Controller to an analog data value that has been detected outside a pre-set range. Also called a threshold or range alarm.

— Pressure and flow deviation algorithms.

— Impact of transients on deviation algorithms and alarms.

— Failure modes.

F.2.7 Pipeline Over/Short Training

Pipeline over/short training is for the Control Center staff and analysts who analyze abnormalities and for engineering support and field staff who are tasked with measurement and metering accuracy. Content may include:

— components of over/short calculations and their signage,

— calibrations and uncertainties of instrumentation used,

— adjustment for line pack.

F.2.8 LDP Awareness Training

LDP awareness training is for support staff who do not need LDP technical training but should have an awareness of the various leak indications that are transmitted to the Control Center. The Control Center staff should receive this training so that they know what level of knowledge is expected from field operations staff with whom they interact. Content may include:

— basics of leak detection tools and techniques;

— recognition of a leak and who to call;

— who might call you to report a leak and how to respond;

— aerial appearance of leaks/ruptures and recognition of areas of developing soil instability, landslides, and subsidence;

— SA locations and characteristics.

F.2.9 LDP Basics Training

LDP basics training is primarily for field operations staff and public entities who may observe a leak. The Control Center staff should receive this training so that they know what level of knowledge is expected from field operations staff and public entities with whom they interact. The Control Center staff may work with the existing public awareness program and outreach efforts to ensure that leak detection is covered in those existing programs.

Training content may include:

— pipelines in the area and how to recognize their location,

— damage prevention when using the ROW,

— leak recognition and response,

— public awareness information in API 1162 including,

— sight, sound, and smell of a leak or the leaked fluid,

— National One Call (811) and state One Call Centers,

— National Pipeline Mapping System (NPMS).

F.2.10 LDP Regulations/Standards Training

LDP regulations/standards training are for the Control Center staff, analysts, engineering support, and management who are involved in specifying LDS requirements and reporting incidents.

— Federal regulations on LDP surveillance and release reporting, such as 49 *CFR* 195.2 (definitions), 195.50, 195.134, 195.412, 195.444, and 195.452(i)(3).

— Proper completion of form PHMSA F 7000-1, *Accident Report—Hazardous Liquid Pipeline Systems*

— State and local regulations on LDPs, surveillance, and release reporting.

— Agreements with citizen advisory councils related to LDPs.

— Proper data entry to API's PPTS (when used).

— Sections that pertain to leak detection in related API documents, including:

  — API 1130,

  — API Publication 1149,

  — API 1113,

  — API 1160,

  — API 1161,

  — API 1162,

  — API 1167,

  — API 1168,

  — API/AOPL White Paper, Liquid Pipeline Rupture Recognition and Response.

F.2.11 LDP Strategy and Culture Training

LDP strategy and culture training is to provide all staff and regulators with a firm understanding of the framework of the pipeline operator's LDP. Content may include:

— a broad overview of the pipeline operator's LDP, strategy, and culture;

— how the pipeline operator's LDP fits the overall pipeline operator culture;

— a brief history of significant historical events;

— promotion of safe operations of the pipeline with no negative repercussions on the staff who take actions during leak indications;

— recognition of the hazard of groupthink in leak alarm analysis and promotion of an open exchange of alarm assessments in the Control Room.

F.2.12 LDP Management Training

LDP management training is specifically for the Control Center staff, analysts, and management as the primary personnel responsible for leadership and successful implementation of the pipeline operator's LDP. Content may include:

— a detailed overview of the pipeline operator's LDP; the structure of this training should follow the outline of this RP for its content.

Particular emphasis should be placed on:

— pipeline operator's strategy and culture;

— overall performance of the LDP, including KPIs and performance targets;

— roles and responsibilities; and

— improvement planning and process.

F.3 Training Methods

F.3.1 General

Table F.2 and subsequent sections describe training roles and training methods.

F.3.2 Classroom

Classroom training should be done through formal, instructor-led, structured classes with verification testing.

Training may include externally based available courses offered by third parties. Testing may be used as a metric to determine effectiveness. This method may be used as a part of initial and refresher training on internally based LDS methods and architecture, externally based LDS methods, over/short analysis, and SCADA deviation alarms.

Table F.2—Roles and Methods of Training

Method of Training	Roles: Management	Control Center	Analyst: Leak Detection Staff	Engineering: Support Staff	IT Group	SCADA Support	Field Operations: Field Staff	Field Operations: ROW Staff	Field Operations: Connecting Facilities Staff	Public: External Response	Public: Government Agencies or Regulators	Public: Land Owners/ROW Users
Classroom (formal)	X	X	X	X	X	X	X	X	X			
Individual Self-Study (informal)		X	X	X	X	X	X					
Procedure Review		X	X									
Interactive Simulation		X										
Playback Simulation		X	X									
Live Simulation		X	X	X		X						
Real Leak Test		X	X				X					
Event Review	X	X	X				X					
On the Job Training		X	X	X	X	X	X	X	X			
Other: Public Awareness		X								X	X	X
Other: Site Visit		X							X	X	X	
Team Training (see Section 11.2.2)	X	X	X	X		X	X	X	X	X	X	X

NOTE Some of the training related to leak detection may be covered as a part of Emergency Response Training.

F.3.3 Individual Self-study

Individual self-study may be done through informal, interactive computer-based learning or a short course of reading material with validation testing.

Individual self-study training may be instructor-assisted, but does not have the formal syllabus of classroom training.

Testing should be used as a metric to determine effectiveness. This method should be used as a part of refresher training for Control Center and LD staff and may be effective as part of awareness-level training.

F.3.4 Procedure Review

The procedure review should consist of a one-on-one procedure review with stakeholders, inclusive of testing and validation of understanding of procedures and policies related to each individual's role.

F.3.5 Interactive Simulations

The interactive simulations may be computer-based, if available. The operator should validate that the simulator is accurate for leaks.

The more sophisticated a simulator is and the more available it is to the Pipeline Controller, the better. It may be able to simulate a sampling of representative lines.

F.3.6 Playback Simulations

SCADA playback simulations should show past alarms and behavior during a leak event or non-leak alarm.

Showing the alarms that happened in what sequence with the actual leak or non-leak alarm may help Pipeline Controllers learn what to look for. It is recommended that the pipeline operator's CPM LDP techniques be pre-configured to capture the data that would be needed to be in alignment with its protocols for conducting a root cause analysis of a real leak.

F.3.7 Live Simulations

For SCADA point analysis, this is primarily accomplished through SCADA data manipulation by modifying pressures, flows or other values used by the alarming logic and by manually overriding them in production to induce an alarm.

These simulations may be announced or unannounced to the Pipeline Controller. Announced drills typically focus on the LDS alarm and response. Unannounced drills include leak recognition by the Pipeline Controller as well.

F.3.8 Real Leak Test

The real leak test is similar to a live simulation, except conducted concurrently with a test of internally based LDS method performance by withdrawing liquid or other means.

For the Control Center staff, the test may be announced or unannounced. If unannounced, this test provides an opportunity to test the Control Center response.

F.3.9 Event Review

Event review and analysis may involve group or individual review of a previous leak event from the pipeline operator's history or from investigative documentation from another event in the pipeline industry.

This should focus on lessons learned and similarities and differences between the event and current operations. In addition, this method should include a review of any emergency response procedures that were used in a real event. This review should focus on how closely the procedures were followed and determining their effectiveness. This may provide an opportunity to discuss the team response to a leak or non-leak indication.

F.3.10 On-the-Job Training (OJT)

OJT may involve shadowing of a more experienced individual in the performance of routine and abnormal tasks.

This method is appropriate for all roles within the pipeline operator's organization.

F.3.11 Other

Other training opportunities are as follows.

— Public Awareness Campaign—Brochures, web sites, media advertisements, and presentations or booths at community forums designed to raise public awareness of the pipelines and commodities transported and how to report a leak. Feedback from landowners, public, and ROW users may be taken to measure effectiveness. The survey may be conducted using the survey questions that are in API 1162.

— Site Visits for Orientation—A walkabout of facilities and ROW features lead by knowledgeable field personnel. Pipeline operator's staff may visit representative pump stations, terminals, metering facilities, and remote valve sites. External first responders may be offered the opportunity to visit facilities and ROW in their areas of response and become familiar with hazards of the commodities that may be leaked. Connecting facility staff should be familiar with pipeline operator's facility at their connection point.

F.4 Testing/Verification of Training

Validating training effectiveness is achieved through testing and review of testing with the students. The type of test used should be appropriate to the method of delivery. These may be as follows.

— A written examination (knowledge test on paper or electronic format) may be used to evaluate student performance in classroom and individual self-study courses and during site visits.

— Student performance during simulations (interactive, playback, and live), real leak tests, and during on-the-job training may be evaluated similar to Operator Qualification (OQ) tasks. (Some may actually constitute an OQ task.) An evaluator assesses the student's skills based on a set of predetermined and documented criteria (such as a checklist).

— Event analysis and review, by their nature, are structured and should follow an existing process for abnormal events of all types and may include discussion and documentation of follow-up activity as the validation.

Evaluation of public awareness training is outlined in API 1162, *Public Awareness Programs for Pipeline Operators.*

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