Final Report

Cost-benefit Analysis of Deploying or Retrofitting External-based Leak Detection Sensors

C-FER Technologies
A SUBSIDIARY OF ALBERTA INNOVATES

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Prepared for the
Pipeline and Hazardous Materials Safety Administration

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November 2020
F226

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Confidential to
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PROJECT TEAM

Cost-benefit Analysis of Deploying or Retrofitting External-based Leak Detection Sensors	C-FER Project: F226	
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EXECUTIVE SUMMARY

External leak detection (ELD) systems are long-term investments having significant benefit potential but also significant costs that are incurred throughout the operational life of the asset. It is therefore reasonable to assume that technology selection should not be based solely on the expected benefits associated with deployment of the ELD technology. A more balanced decision making approach involves giving consideration to both the benefits and the costs of system deployment. Cost-benefit analysis (CBA) provides a systematic means of weighing the benefits of a course of action against the associated costs. If the benefits and costs can both be expressed in monetary terms, CBA provides an objective basis for determining if an investment is justifiable (by determining whether the benefits outweigh the costs). It also provides a basis for comparing or ranking investment options based on the value of one or more objective CBA evaluation metrics.

This project was carried out to develop a framework for conducting CBA on candidate ELD systems for use on hazardous liquid and natural gas transmission pipelines (i.e. the “CBA Framework”). The application of the CBA Framework developed in this project is illustrated via a demonstration exercise in which a CBA was performed to evaluate and compare three ELD systems for possible implementation on a hypothetical new construction pipeline (i.e. the “demonstration pipeline”). The main components of the CBA Framework, as well as an abbreviated summary of the CBA Framework demonstration exercise, are summarized below.

Framework Components

Deployment Configuration Identification

The first component of the CBA Framework provides guidance on identifying, characterizing and ranking viable ELD deployment configurations. In this study, deployment configuration refers to how a particular ELD system is both configured and installed. The primary purpose of this section is to manage the level of effort required to conduct the CBA by identifying deployment configurations with the most potential to generate favorable cost-benefit scores.

Cost Estimation

The second component of the CBA Framework discusses an approach for sourcing and consolidating the information required to accurately estimate life cycle costs of deploying and operating ELD systems. The approach assumes that costs are broken down into initial costs, which are associated with ELD system procurement and installation, and recurring costs, which are associated with the periodic operation and maintenance of the candidate ELD systems. In estimating initial costs, it is recommended that candidate ELD technology vendors be consulted. It is emphasized that the accuracy of the initial cost estimates provided by the technology vendors

will depend on the quality and completeness of the information provided to them, specifically, the amount of detail describing the deployment configurations and the performance requirements. Similarly, in estimating recurring costs, it is recommended that the ELD technology vendors be consulted to obtain a better understanding of what operation and maintenance expenditures can be expected over the operating life of the ELD system.

Benefit Characterization

The third component of the CBA Framework provides guidance for evaluating and quantifying the benefits that can be achieved by ELD implementation, the objective being to calculate quantified benefits (preferably in terms of equivalent dollars) for each of the preferred deployment configurations. This calculation differs according to which of the following principal benefit categories are being considered:

- Environmental protection enhancements (based on the potential reduction in the quantity released in the event of line failure); and
- Safety enhancements (based on the potential reduction in fatalities and injuries due to a reduction in failures).

Environmental protection and life safety benefits are calculated in similar ways, and are based on the following key model components:

- Baseline Estimate: The baseline release volume is the expected release volume that would result, given that a release has occurred, assuming no ELD systems are deployed. The baseline fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming no ELD systems are deployed.
- Reduced Estimate: The reduced release volume is the expected release volume that would result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest. The reduced fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
- Failure Rate Estimate: The failure rate represents the expected rate of occurrence of pipeline releases over a given time period (typically one year) and over a particular length of pipeline.
- Monetization Models: Monetization models are required to convert the calculated reduction in expected release volume into an equivalent dollar measure for the expected environmental impact reduction achieved. Monetization models are also required to convert the calculated reduction in expected fatalities and injuries into a dollar equivalent.

Different approaches can be used for combining the listed model components to estimate the environmental protection and life safety benefits. Most approaches can be classified as deterministic or probabilistic approaches, or hybrid approaches that combine elements of each of the deterministic and probabilistic approaches.

Cost-benefit Analysis

The fourth and final component of the CBA Framework provides guidance on combining the calculated costs and benefits into a meaningful evaluation metric that can be used to objectively compare different ELD deployment alternatives.

Benefits are realized and costs are incurred at different times throughout the ELD system's operational life. Therefore, it is critical to discount all benefits and costs to present-day dollars. Once all costs and benefits are discounted using an appropriate discount rate, they can be combined into the chosen evaluation metric to serve as a basis for decision making. The CBA Framework describes different methods that are available for combining the present-day costs and benefits into one or more useful cost-benefit measures:

- Net present value (NPV): Defined as the arithmetical difference between the present benefits and the present costs;
- Benefit-cost ratio (BCR): Defined as the ratio of the present benefits to the present costs; and
- Cost effectiveness ratio (CER): Defined as the ratio of the present value of costs (i.e. *PVC*) to the total benefits expressed in non-monetary units.

If the input parameters used in the calculation of the costs and/or the benefits are associated with a high degree of uncertainty, it is recommended these parameters be included in a single variable testing sensitivity analysis. The results of this analysis can be used to assess the degree to which the highly uncertain parameters can impact the adopted evaluation metric value or values. Input parameters with a high degree of uncertainty that are shown to have a significant impact on the resulting evaluation metric might warrant additional effort to reduce the parameter uncertainty by collecting additional data or making more informed assumptions.

The preferred deployment configurations serve as a basis for conducting a scenario analysis. The scenario analysis is central to objectively evaluating the possible alternatives in terms of their ability to generate a net positive value over the adopted evaluation timescale. The results of the scenario analysis could be used to simply compare different alternatives in relative terms, or to provide a quantitative measure of the expected overall value associated with different alternatives. The results of the scenario analysis could also provide a basis for narrowing down the deployment configurations prior to performing a second, more comprehensive iteration of the CBA.

Framework Demonstration

In the CBA Framework demonstration exercise, three hypothetical ELD systems were considered for possible deployment on the demonstration pipeline: a distributed acoustic sensing system, a vapor sensing tube system, and a distributed temperature sensing system. These systems are representative of commercial ELD systems that are typically installed on existing transmission pipelines and many pipeline operating companies are reasonably familiar with their capabilities.

The selection of the demonstration pipeline was guided by two primary considerations: to facilitate demonstration of selected key aspects of the CBA Framework, and to make the findings of the demonstration exercise as broadly applicable as possible. To this end, the demonstration pipeline was defined as a new-construction, subsurface pipeline, transporting crude oil, with a nominal operational life cycle of 50 years. ELD was considered for deployment on a 155-mile section of the demonstration pipeline.

The overall benefit resulting from ELD deployment was assumed to consist predominantly of environmental protection enhancements. Given the relatively low life safety risks associated with the transport of crude oil, especially compared to natural gas, life safety benefits were assumed not to be significant and were, therefore, not considered in the demonstration exercise.

The environmental protection benefits were calculated using a hybrid approach that is consistent with the guidance provided in the CBA Framework. This approach was selected because new-construction pipelines are assumed not to have in-line inspection data on damage features that can be leveraged in a full probabilistic analysis. In the adopted hybrid analysis approach, the baseline release volume, the reduced release volume and the failure rate were calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variable analysis input distributions.

The costs and monetized benefits were temporally distributed over the pipeline's operational life span and converted into present-day equivalent values using a nominal social discount rate of 3%. A single variable test was then carried out to identify input parameters with the greatest impact on the adopted evaluation metrics (i.e. NPV and BCR). These parameters were flagged and additional consideration was given to them in order to minimize the associated uncertainty to the extent possible. The NPVs and BCR values were then calculated for each of the preferred deployment configurations in both high consequence areas (HCAs) and non-HCAs. It was found that the candidate ELD systems, when deployed in HCA locations, are generally cost effective, whereas they are not cost effective when deployed in non-HCA locations. Selection of a preferred alternative was based on NPV. For expanded ELD deployment on other sections of the demonstration pipeline, including on non-HCA sections, it may be more appropriate to fix the ELD budget rather than the deployment length. In these cases, it would be more appropriate to select the preferred alternative based on BCR rather than NPV.

1. INTRODUCTION

1.1 Terms of Reference

This document is the primary deliverable for the project "Cost-benefit Analysis of Deploying or Retrofitting External-based Leak Detection Sensors" that was carried out by C-FER Technologies (1999) Inc. ("C-FER") for the US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). This project was carried out to develop a framework for conducting cost-benefit analysis (CBA) on candidate external leak detection (ELD) systems for use on hazardous liquid and natural gas transmission pipelines. The work was carried out under the guidance of a Technical Advisory Panel (TAP), consisting of experts from the pipeline industry, who provided input throughout the project.

1.2 Objective

The objective of this project was to generate and deliver new knowledge in the form of a document outlining a methodology (i.e. a 'framework') for performing CBA on candidate ELD systems for use on hazardous liquid and natural gas transmission pipelines. The output obtained from the application of this methodology will inform technology deployment decisions, and enable operators to tailor system requirements and deployment configurations to their pipeline systems.

A secondary project objective was to demonstrate and illustrate the application of the External Leak Detection Cost-benefit Analysis Framework developed in this project. This was achieved through a demonstration exercise in which a hypothetical CBA was performed to evaluate and compare three ELD systems for possible implementation on a hypothetical new construction pipeline (i.e. the "demonstration pipeline"). The demonstration exercise is documented and summarized in Appendix A.

1.3 Background

In recent years, pipeline leak detection has largely been achieved through computational pipeline monitoring (CPM) methods, which monitor and interpret internal operating parameters (e.g. pressure and flow) for the purpose of detecting conditions indicative of a leak. CPM is reasonably effective; however, it can only reliably detect leaks that are larger than about 1% of the normal pipeline flow rate. This limitation has prompted the development of a new generation of leak detection technologies consisting primarily of sensors that are installed outside the pipeline. These sensors are able to recognize leakage by interacting with the released fluid or the associated release energy (i.e. acoustic, thermal or mechanical). These technologies, collectively referred to as ELD systems, have the ability to detect leak rates that are much smaller in magnitude than 1% of the pipeline flow rate. When deployed alongside existing CPM systems, ELD systems have the potential to greatly improve overall leak detection capability by lowering the detection sensitivity floor to below that of current CPM systems.

ELD systems can be costly, especially when deployed retroactively and over significant distances. Therefore, when considering implementing an ELD system on a pipeline, it is important to understand and consider the trade-offs that exist between the cost of deploying a particular ELD system (or sensor) in a particular location and the associated performance that would be expected from that ELD system in that location (i.e. some deployment positions and ELD technologies might be more cost effective to procure and install, but might not perform as well and, therefore, might not provide as much benefit over the course of the asset's operational life). ELD systems are long-term investments with benefits and costs incurred throughout the operational life cycle of the asset. Technology selection should not be based solely on the expected performance of the ELD technology. Rather, consideration should be given to whether the overall benefits associated with ELD deployment justify the costs.

CBA provides a systematic means of weighing the benefits of a course of action against the associated costs. If the benefits and costs can both be expressed in monetary terms, CBA provides an objective basis for determining if an investment is justifiable (by determining whether the benefits outweigh the costs). It also provides a basis for comparing or ranking investment options based on the value of one or more objective evaluation metrics. Even if the benefits of a course of action are not expressed in monetary terms, CBA can still serve to objectively rank alternative actions and thereby identify preferred options.

The CBA methodology for evaluating ELD systems documented herein will provide operators with a framework for identifying, collecting and using relevant information for informed decision making regarding ELD technology selection and deployment.

1.4 Framework Outline

The developed CBA framework is comprised of four primary elements, each of which is discussed in a separate section of this document. A brief summary of the information covered in each of the four major report sections is provided below:

Deployment Configuration Identification

Section 2 provides guidance on identifying and characterizing viable ELD deployment configurations. It also provides a means by which to prioritize the identified deployment configurations such that only those with the most potential to generate favorable cost-benefit scores are carried forward (i.e. the preferred deployment configurations).

Cost Estimation

Section 3 provides guidance for sourcing and consolidating the information required to accurately estimate costs associated with ELD system procurement, installation and maintenance for each of the preferred deployment configurations that were identified in Section 2.

Benefit Characterization

Section 4 provides guidance on estimating the total benefit that can be achieved with ELD implementation, expressed in equivalent dollar terms, for each of the preferred deployment configurations that were identified in Section 2.

Cost-benefit Analysis

Section 5 provides guidance on combining the calculated costs and benefits, obtained in Sections 3 and 4, respectively, into a meaningful evaluation metric that can be used to objectively compare different ELD deployment alternatives.

1.5 Acronyms

ALARP	As Low As Reasonably Practicable
BCR	Benefit-cost Ratio
CBA	Cost-benefit Analysis
CER	Cost Effectiveness Ratio
CFD	Computational Fluid Dynamics
CPM	Computational Pipeline Monitoring
DAS	Distributed Acoustic Sensing
DOT	United States Department of Transportation
DTS	Distributed Temperature Sensing
ELD	External Leak Detection

EPA	United States Environmental Protection Agency
GDP	Gross Domestic Product
GHG	Green House Gas
GWP	Global Warming Potential
HDPE	High Density Polyethylene
HSC	Hydrocarbon Sensing Cable
HVP	High Vapor Pressure
IAM	Integrated Assessment Model
ILI	Inline Inspection
IWG	Interagency Working Group
LBB	Leak Before Break
LFL	Lower Flammability Limit
LVP	Low Vapor Pressure
MAIS	Maximum Abbreviated Injury Scale
NPV	Net Present Value
PIR	Potential Impact Radius
PVB	Present Value Benefits
PVC	Present Value Costs
ROW	Right-of-way
RP	Revealed Preference
SCADA	Supervisory Control and Data Acquisition

SCC	Social Cost of Carbon
SME	Subject Matter Expert
SP	Stated Preference
VOC	Volatile Organic Compound
VSL	Value of a Statistical Life
VST	Vapor Sensing Tube

2. DEPLOYMENT CONFIGURATION IDENTIFICATION

2.1 Overview

This section provides guidance for identifying and characterizing viable ELD deployment configurations. It also provides a means by which to prioritize the identified deployment configurations such that only those with the most potential to generate favorable cost-benefit scores are carried forward (i.e. the preferred deployment configurations).

ELD systems can be deployed in many different locations and orientations relative to the pipeline. They can also be deployed along with auxiliary components, such as conduit, straps or supports. The performance of, as well as the installation cost associated with, a given ELD system is significantly impacted by the way it is deployed in the field. It is, therefore, important to identify and characterize the possible deployment configurations for each ELD technology being considered in the CBA. In this study, deployment configuration refers to how a particular ELD system is both configured and installed. It describes the extrinsic parameters of an ELD system in its deployed state and, for the purpose of this framework, is limited to parameters that are known to, or that are likely to, impact the ELD system's performance.

Identifying and ranking candidate deployment configurations consists of the following key steps:

1. Identify candidate ELD technology vendors
2. Establish deployment configuration characteristics
3. Define deployment configurations
4. Rank deployment configurations

These steps are discussed individually in the following sections.

2.2 Identify Candidate ELD Technology Vendors

To obtain an initial list of vendors for consideration (i.e. candidate ELD technologies), a market survey should first be conducted. The purpose of the market survey is to identify viable technologies for consideration based on their perceived ability to meet performance requirements specific to the pipeline under consideration. Following the market survey, a vendor questionnaire, aimed at gathering pertinent information about the candidate technologies, should be generated and distributed. The purpose of the vendor questionnaire is to facilitate the collection of targeted information regarding the candidate vendors, their services and the performance of their systems as they relate to the specific performance requirements. Finally, a stepwise process should be followed for scoring the technologies, based on the responses obtained from the questionnaires, to ultimately arrive at a shortlist of vendors for further consideration in the CBA. A report prepared for PHMSA in 2018 provides detailed guidance for conducting an ELD technology market survey and for analyzing and interpreting the results (1).

Bussière et al. (1) suggest developing numerical scores for each of the candidate technologies. The proposed scores are developed by comparing the information obtained from the vendor questionnaire to the application environments and other project requirements. An overall technology score for each candidate technology can then be derived by developing an evaluation matrix. The evaluation matrix is a tool that allows for the systematic evaluation of specific performance requirements by comparing the vendors' responses to the questionnaire against well-defined criteria. The final scores then inform the identification of preferred candidate technologies.

2.3 Establish Deployment Configuration Characteristics

In identifying and prioritizing viable deployment configurations, it is first recommended that a consistent basis be established for characterizing the various deployment configurations that will be identified. To assist with this process, a set of basic characteristics, which can be used to define possible deployment configurations, should be established.

Deployment configuration characteristics are described, and guidance is provided below for determining which characteristics are most relevant given ELD technology type, sensor design and the asset being monitored. Note that the deployment configuration characteristics do not represent an exhaustive list. It is acknowledged that, in specific scenarios, additional or different characteristics might need to be considered; however, it is believed that, in most cases, the list provided is sufficient or, at the very least, it serves as a good starting point for understanding which characteristics are important.

Sensor Position

Sensor position refers to the sensor's location relative to the pipeline, as well as other relevant reference objects or reference locations (i.e. trench wall, soil surface, subsurface valves). At a minimum, it is recommended that a sensor's location be described in terms of its axial, radial and circumferential position relative to the pipeline.[1] Depending on the ELD system, it might also be necessary to characterize sensor position with reference to other reference locations, such as

[1] For distributed sensors (e.g. fiber optic cables), the placement position need only be described in terms of radial and circumferential location.

distance from pump/compressor stations or distance from the ground surface (i.e. amount of cover).

Sensor Orientation

Sensor orientation refers to the angular position of an ELD sensor relative to the reference frame that it is attached to. Together, the sensor position and sensor orientation fully describe how the ELD sensor is placed in space. Some ELD sensors are omnidirectional and their performance is relatively independent of sensor orientation. Others, such as geophones and accelerometers, are inherently directional and sensor orientation plays a significant role in system performance.

Placement Pattern

When multiple ELD sensors are deployed in a particular location, they are often arranged in a repeating array. The placement pattern describes the shape, as well as the spacing, and the total number of sensors in the array. When only a single continuous sensor is deployed, as is often the case with distributed sensing systems, placement pattern is not relevant.

Placement Environment

Placement environment describes the relevant physical characteristics of the environment surrounding a particular ELD sensor or group of sensors. ELD technologies are sensitive to different environmental characteristics and, therefore, the placement environment is defined differently depending on the ELD technology that is being considered. For example, the soil's thermal conductivity might be an important parameter for ELD systems relying on temperature measurement, but it is less relevant for ELD systems relying on acoustic measurement.

Use of Auxiliary Components

Auxiliary components include passive structures deployed along with the ELD sensor(s), such as conduit. It also describes the geometry of the components and the manner in which they interact with the ELD sensor. For example, a distributed fiber optic cable might be blown or pulled into a high density polyethylene (HDPE) conduit having a known outer diameter and thickness.

2.4 Define Deployment Configurations

Deployment configurations are identified by first considering all the unique combinations of viable deployment configuration characteristics that are possible for each of the candidate ELD technologies. Guidance from the candidate ELD technology vendors can then help identify which combinations are applicable to each ELD technology being considered. The ELD technology vendors might recommend multiple deployment options, or they may simply identify the deployment configuration with the best expected performance. Because different deployment configurations might be associated with different costs, it is important to consider all viable (or practical) deployment configurations in the CBA, even if they may not yield the best possible performance. If the ELD technology vendor is not able to estimate ELD system performance for all deployment configurations under consideration, it might be necessary to conduct additional testing or modeling. Bussière et al. (1) provide detailed guidance for experimentally evaluating ELD performance.

Because some deployment configuration parameters (e.g. sensor position and placement environment) might consist of one or more continuous variables[2], the number of unique combinations of deployment configuration parameters could be infinite. To address this, it is recommended that continuous deployment configuration parameters be categorized such that the subsequent categories result in distinct levels of perceived deployability and interference, where deployability and interference are defined as follows:

- <u>Deployability</u> - the ease of installation associated with a particular deployment configuration.
- <u>Interference</u> - the predicted level of impact that an ELD system (or sensor), associated with a particular deployment configuration, would have on the pipeline's operation (integrity digs, preventative maintenance, etc.).

In cases where considering deployability and interference only leads to discrete ranges of a particular deployment configuration parameter rather than discrete categorical values, it is recommended that the value within each range that is believed to yield the best relative performance only be considered. Here, relative performance is defined as an approximate aggregate measure of overall performance (i.e. sensitivity, robustness, accuracy and reliability)[3] for a given ELD technology.

Deployability, interference and relative performance are not only useful in categorizing continuous variables, they can also be used to reduce the number of categories associated with a particular categorized variable, thereby simplifying the deployment configuration identification process. Categorizing continuous deployment configuration parameters (or simplifying selected categorical deployment configuration parameters) will likely require consultation with the candidate ELD technology vendors, as well as an understanding of what key factors are capable of influencing deployability, interference, and relative performance. To this end, the following key

[2] Unlike discrete variables, continuous variables can take on an uncountable set of values. For example, any range of real numbers a and b with $a, b \in \mathbb{R}; a \neq b$ is infinite and uncountable.

[3] Relative performance should be based on, or align with, the performance metrics outlined in existing relevant recommended practice and standards, such as API 1130 (2) and API 1175 (3), to the extent possible.

factors should be considered when evaluating the degree of deployability, interference and relative performance of a potential deployment configuration:

Soil Properties

Soil properties are the mechanical properties of the native soil, backfill and bedding material (if applicable). They are limited to properties capable of impacting ELD sensor installation on new or existing pipelines. Accordingly, soil properties, as defined here, might include, but are not limited to: density, compaction, heterogeneity, moisture content and composition. Soil properties can affect ELD system performance and also impact the equipment usage costs.

Equipment Usage Costs

Equipment usage costs are the aggregated equipment costs of deploying a single sensor (or a unit length of sensor cable) in a particular setting (i.e. as characterized by the local soil properties). Equipment, in this context, refers to any drilling, plowing and/or excavation equipment (mechanical or otherwise) that might be used in the installation of candidate ELD sensors. The aggregated costs should include all expenses that are directly related to the ELD sensor deployment (equipment usage rates, transportation to and from the job site, operator compensation, etc.). Equipment usage costs alone cannot be used to define deployability and interference. Rather, this information is used in combination with other key considerations to inform the determination of deployability and interference.

Exclusion Zone Characterization

Exclusion zones are defined as the radial distance relative to an existing pipeline within which mechanical digging, plowing and or excavating is not permitted. Exclusion zones are typically on the order of 0.30 to 0.61 meters from the wall of the pipeline, but the exact value depends on the operator and on the environment surrounding the pipeline. A report prepared for Pipeline Research Council International, Inc. (PRCI) in 2015 provides a detailed discussion about exclusion zones and how they can affect retroactive deployment of cable-based ELD systems on existing pipelines (4). An understanding of exclusion zones, in combination with information about soil properties and equipment usage costs, can be used to establish areas with different relative ELD deployment costs. For example, a particular ELD sensor installed within the exclusion zone might be significantly more expensive to deploy compared to the same sensor installed outside the defined exclusion zone. In many cases, this is because only hydro-vac equipment, which tends to have a higher equipment usage cost compared to mechanical excavation equipment, is permitted within the exclusion zone.

Equipment Capabilities

Equipment capabilities are the physical capabilities of any drilling, plowing and/or excavation equipment (mechanical or otherwise) that might be used in the installation of candidate ELD sensors. Equipment capabilities might also specify different equipment usage costs depending on how the equipment is being used. For example, a directionally drilled hole might be associated with a higher equipment usage costs, compared to a straight hole of similar diameter and length. Examples of equipment capabilities might include, but aren't limited to: maximum drilling depth and diameter, maximum plowing depth and width, drilling directionality, and positional accuracy. An understanding of equipment capabilities, in combination with soil properties and equipment usage costs, can be used to establish areas with different relative deployment costs. For example, a particular ELD sensor installed underneath the pipeline might be significantly more expensive to deploy compared to the same ELD sensor installed at a similar depth (and, for the sake of comparison, within the same exclusion zone), but beside the pipeline rather than underneath it. This is because the sensor installed underneath the pipeline requires directional drilling capabilities, which are associated with higher equipment usage costs, whereas the sensor installed beside the pipeline does not.

In-situ Obstacles

In-situ obstacles are any object, equipment or infrastructure that resides near potential ELD deployment locations that could interfere with, or prevent, the installation of ELD sensors. Examples of in-situ obstacles include, but aren't limited to: communication cables, power cables, subsurface valves and known geological formations. An understanding of in-situ obstacles, in combination with soil properties and equipment usage costs, could be used to establish areas with different relative deployment costs and different degrees of operational interference potential. For example, communication cable on one side of the pipeline might lead to increased ELD deployment costs within a particular radius of the communication cable. It might also lead to increased operational interference because ELD sensors installed there could potentially interfere with maintenance procedures related to the subsurface communication cable.

Operational Activities

Operational activities are any anticipated activities or actions related to the pipeline's operation that might be impacted at some point by the presence of ELD sensors or associated infrastructure. An understanding of possible operational activities, including information about how such activities might be impacted by the presence of ELD systems, could be used to establish areas with different degrees of operational interference potential. For example, ELD sensors installed on the surface of the pipeline might interfere with future pipeline repair activities, thereby potentially incurring additional maintenance costs over the duration of the pipeline's life. In comparison, the same sensors installed away from the pipe surface might not be expected to interfere with repair activities and, therefore, would not be expected to incur additional maintenance costs.

Trench Characteristics

Trench characteristics are the characteristics of the open excavation (i.e. the trench) where the pipeline will be deployed. Trench characteristics are limited to characteristics that are capable of impacting ELD sensor installation and ELD system performance. Of particular importance in the current context are: the trench geometry (i.e. depth and width), the height of the bedding layer (if applicable) and the cover depth (i.e. the distance separating the top of the pipeline and the soil surface). Trench characteristics alone cannot be used to define deployability and interference. Rather, this information is used in combination with other key considerations to inform the characterization of deployability, interference and relative performance.

Construction Practices

Construction practices refer to the collection of procedures, processes and/or customs employed by the construction contractors during pipeline construction that are likely to impact ELD sensor installation. Of particular importance in the context of deployment zone selection are: sequencing scheme, safety requirements and use of auxiliary components. The sequencing scheme is the order in which major elements (e.g. pipe, bedding, backfill, ELD sensors) are installed. Safety requirements are any safety-related procedures that could impact the way ELD sensors are deployed or that could prevent deployment in specific areas. Finally, auxiliary components are any additional structures that might be required to support or house ELD sensors that are capable of impacting ELD sensor installation (e.g. pipe stands, conduit for ELD sensors, pipe straps for ELD sensors). An understanding of relevant construction practices, in combination with soil properties and trench characteristics, can be used to establish areas with different relative deployment costs and different degrees of operational interference potential. For example, a safety requirement might prevent workers from entering the trench, thereby preventing them from performing work of any nature, including installing ELD sensors in certain areas that are difficult to access from outside the trench. Such a restriction might mean that only certain ELD positions are possible without incurring additional expenses to ensure worker safety.

Ground Surface Properties

Ground surface properties are the characteristics of the ground surface that are likely to impact ELD sensor installation and relative performance. To this end, ground surface properties, as defined here, might include, but are not limited to: vegetation type, soil type or snow cover. An understanding of ground surface properties could inform how certain ELD systems are expected to perform, as well as how certain ELD sensors are to be installed.

Example deployment configurations for a hypothetical below-ground, new-construction pipeline are provided in the demonstration exercise outlined in Appendix A.

2.5 Rank Deployment Configurations

Once viable deployment configurations have been established and candidate ELD technology vendors have been identified, it is possible to characterize and rank the identified deployment configurations. The objective is to only carry forward the highest ranking and, therefore, the most promising deployment configurations. The recommended procedure involves assigning two relative scores to each of the identified deployment configuration for a given candidate ELD technology. The suggested scores are defined as follows:

- Relative Cost Score: The relative cost score is intended to reflect the lifetime cost of deploying and operating a given ELD system in a particular deployment configuration relative to that of all other candidate deployment configurations. It is obtained by considering the joint degree of deployability and interference associated with each of the candidate deployment configurations.
- Relative Benefit Score: The relative benefit score is intended to reflect the anticipated overall performance of a particular ELD system relative to that of all other candidate deployment configurations. The relative benefit score should be based on the relative performance defined previously (i.e. it represents an aggregate approximate measure of overall ELD performance for a given deployment configuration). Determining the benefit score will likely require consultation with the candidate ELD technology vendors and, possibly, independent testing and/or modeling.

It is acknowledged that the relative cost and benefit scores are, at this stage, only approximations. They are not intended to reflect precise, absolute costs or benefits (these will be evaluated in subsequent steps of the process). Accordingly, individual relative cost scores should be assigned based on the anticipated overall cost (as approximated by the relative degree of deployability and interference) relative to the perceived lowest and highest costs among the candidate deployment configurations. Similarly, individual relative benefit scores should be assigned based on the anticipated overall benefit (as approximated by the aggregated ELD system performance) relative to the perceived lowest and highest benefit values among the candidate deployment configurations. The recommendation is to use a simple scoring scale consisting of sequentially ranked integers ranging from 1 to 10 (other scale ranges can be used if more granularity is required), with 1 representing the deployment configurations associated with the highest cost or lowest benefit and 10 representing the deployment configurations with the lowest cost or highest benefit.

Once relative cost and benefit scores are developed for each of the identified deployment configurations, the next step is to combine the scores (through multiplication) to obtain an overall deployment ranking score. Only the deployment configurations with the highest overall scores (i.e. “the preferred deployment configurations”) will be considered in the full CBA. The final number of deployment configurations to carry forward will largely depend on the level of effort the operator is willing to devote to the CBA. It will also depend on the individual overall scores assigned to each deployment configuration. For example, suppose the operator wishes to carry forward three deployment configurations; however, the third and fourth ranked deployment configurations have very similar overall scores. In this case, and in acknowledgement of the uncertainty inherent in this preliminary ranking exercise, it might not be sensible to eliminate the fourth ranked deployment configuration in favor of the third. Provided there is sufficient separation between the scores of the fourth and fifth ranked deployment configurations, the recommendation would be to carry forward the first four deployment configurations instead of the first three. If resource constraints strictly prevent expanding the number of deployment configurations to carry forward, then the recommendation would be to return to the cost and benefit rankings to attempt to refine and improve the original estimates before finalizing the set of configurations to carry forward.

3. COST ESTIMATION

3.1 Overview

This section provides guidance for sourcing and consolidating the information required to accurately estimate the initial costs associated with ELD system procurement and installation, and the recurring costs associated with periodic maintenance expenditures required to ensure system functionality over the operating life of the pipeline. These cost estimates are required inputs for the CBA framework described in Section 5.

In estimating the costs associated with deploying a particular ELD system, it is important to acquire initial and recurring cost estimates for each of the preferred deployment configurations that were identified in Section 2. The following subsections provide guidance for obtaining cost estimates for the candidate ELD technologies given specific deployment configurations and performance requirements.

3.2 Initial Costs

Initial costs are comprised of procurement costs and installation costs. They are usually incurred concurrently with the pipeline construction, but might occur at different times throughout the pipeline's operational life cycle (e.g. retrofit or staged ELD deployments).

3.2.1 Procurement

Procurement costs are associated with the ELD equipment itself and might include such items as:

- ELD sensors (e.g. fiber optic cable);
- Data acquisition equipment (e.g. interrogator units);
- Power provisions (e.g. batteries, generators, solar panels);
- Communications equipment (e.g. cable/wire, wireless transmitters); and
- Design and consulting labor.

In estimating procurement costs, it is recommended that the candidate ELD technology vendors be consulted. The accuracy of the procurement cost estimates provided by the technology vendors will depend on the accuracy of the information they are provided, specifically, the amount of detail describing the deployment configurations and the performance requirements. Poorly defined deployment configurations and/or performance requirements could lead technology vendors to make incorrect assumptions, leading to inaccurate procurement cost estimates.

Therefore, it is recommended that a document be produced and disturbed to the candidate ELD technology vendors that contains a detailed description of the candidate deployment configurations, as well as the performance requirements (i.e. a procurement cost inquiry document). The document should provide the necessary background information describing the pipeline system for which the ELD is required, as well as a characterization of the pipeline right-of-way (ROW), including any data that is deemed to be pertinent given the technologies under consideration. Bussière et al. (1) provide guidance for identifying what information is important given different types of ELD technologies and can therefore serve as a useful reference for determining what information to include in the procurement cost inquiry document.

Lastly, it is recommended that accounting for depreciation expenses of the ELD asset be avoided. As a general principle, only real costs (i.e. changes in real resources) should be taken into account. The decreasing value of the asset is represented by the difference in the purchase price and the eventual disposal price at the end of the asset's life[4]; accounting for depreciation expenses would double-count the capital investment that has already been taken into account[5].

3.2.2 Installation

Installation costs are associated with the construction and commissioning of the ELD systems, and might include the following:

- Construction labor costs;
- Equipment rental costs (e.g. excavation equipment, transportation equipment);
- Material costs (e.g. conduit, backfill material, strapping); and
- Commissioning and calibration costs.

In estimating installation costs, it is recommended that construction contractors and technology vendors be consulted. The accuracy of the installation cost estimates will depend on the level of detail present in the preferred deployment configurations, as well as the level of detail present in the ROW characterization.

[4] Installation costs constitute a significant portion of the overall costs associated with ELD deployment. Because installation costs cannot be recovered at the end of the ELD system's life and it is not practical to remove buried sensors for re-sale, it is recommended that a disposal price of zero for most ELD systems be assumed.
[5] The tax effects of depreciation may be considered.

When ELD installation occurs concurrently with pipeline construction (i.e. new-construction ELD deployments as opposed to retrofit ELD deployments), it is also important to consider potential costs associated with the interference to the pipeline construction process. To minimize the interference with the pipeline's construction, it might be necessary to modify the ELD sensor deployment process. For example, to better align with the pipeline construction process, long, continuous ELD sensors, such as distributed cables (distributed acoustic sensing (DAS), distributed temperature sensing (DTS), hydrocarbon sensing cable (HSC), vapor sensing tube (VST), etc.), might require conduit to be deployed alongside the pipeline. The sensor cable is then pulled or blown in at a later date. Such a requirement would likely impact the installation costs and should be considered when estimating installation costs.

Some ELD systems require some degree of on-site tuning and/or calibration prior to operation. Direct costs associated with such activities should be provided by the ELD technology vendor. These activities might also be associated with other, indirect costs, examples of which include costs associated with supervising the calibration work and ensuring the safety of the third-party workers completing the work.

3.3 Recurring Costs

Recurring costs are those that are incurred periodically over the course of the ELD system's operational life. They are comprised of operation and maintenance costs, costs associated with responding to false alarms and cost of interference to pipeline operation.

3.3.1 Operation and Maintenance

Operation and maintenance costs are required to ensure adequate performance over the course of the ELD system's operational life. These could include the following:

- Repair costs,
- Scheduled preventative maintenance costs,
- Upgrade costs, and
- Alarm management and personnel training costs.

It is recommended that the ELD technology vendors be consulted to better understand what expenditures may result with regard to operation and maintenance over the operating life of the ELD system. Some technology vendors might have recurring service fees, such as an annual subscription, which might include additional services such as: an alarm management service, personnel training, maintenance activities and periodic software upgrades. Other technology vendors might simply have a one-time, up-front equipment charge, which doesn't include any additional services. It is important to know whether or not additional recurring fees are to be expected and, if so, what services they afford.

3.3.2 Responding to False Alarms

The annual cost associated with responding to false alarms is a function of the expected annual false alarm rate[6] per unit length of monitored pipeline, the average cost of excavation per unit length and the locational accuracy of the ELD system. It might be possible to have different false alarm rates or different locational accuracies for different parts of the pipeline. In this case, it is recommended that the contributions of each pipeline section for which a different false alarm rate, excavation cost and/or locational accuracy might exist be summed as follows[7]:

$$C_{FR} = \sum_{i=1}^{n} R_{FA_i} \times C_{E_i} \times A_{L_i} \times L_i \qquad [3.1]$$

In the expression above, C_{FR} is the expected annual cost of responding to false alarms, $R_{FA_i}$is the expected annual false alarm rate[8] per unit length of monitored pipeline for the i^{th} section of pipeline, C_{E_i} is the average cost of excavation per unit length for the i^{th} section of pipeline, $A_{L_i}$is the locational accuracy of the ELD system for the i^{th} section of pipeline and L_i is the length of the i^{th} section of pipeline. For above-ground pipelines, excavation costs are virtually zero; however, there are likely costs associate with mobilizing personnel and equipment to investigate the alarm. In the above expression, it is assumed that small leak alarms do not precipitate immediate line

[6] Not all false alarms precipitate excavation; some might be dismissed outright while others might only require a site investigation. The false alarm rate used in this calculation considers only false alarms which provoke excavation activities. False alarms that do not lead to excavation still have the capacity to invoke additional costs (i.e. costs associated with mobilizing personnel to the leak site to investigate the leak, as well as additional costs associated with purchasing and operating leak locating aids, such as ground penetrating radar or volatile organic compound (VOC) sensors); however, it is assumed that such costs are small in comparison to those associated with excavation activities.

[7] This expression represents a conservative approach to estimating the cost of responding to false alarms because it assumes that the linear length of any given excavation is equivalent to the ELD system's locational accuracy. In reality, upon excavating a suspected leak, the precise leak location is likely discovered before a length equivalent to the ELD system's locational accuracy has been excavated. If the leak is equally likely to be anywhere within the ELD system's locational accuracy interval, then the expected excavation length would be half of the ELD system's locational accuracy.

[8] Equation [3.1] conservatively assumes that all alarms precipitate excavation. A more realistic estimate would consider information concerning the proportion of leak alarms that precipitate excavation. This proportion would then multiply the terms in Equation [3.1].

isolation or shutdown. On that basis, there are no costs associated with lost production due to line isolation or shutdown. If small leak alarms do precipitate line isolation or shutdown, then the associated costs should be considered and the above expression should be modified to account for them.

The expected annual number of false alarms per unit length of monitored pipeline, as well as the expected locational accuracy of the candidate ELD systems, should be provided by the technology vendors. If they cannot provide reliable and relevant data to support their performance claims, it may be necessary to independently verify the claims through large-scale testing, bench-scale testing, field pilots and/or numerical modeling. Bussière et. al (1) provides a systematic methodology to facilitate the process of identifying information gaps in vendor performance claims.

The average cost of excavation per unit length is a function of environmental parameters such as soil properties, local climate and burial depth of the pipeline (refer to Section 2.4 for more detail regarding estimating excavation costs). It is recommended to consult with appropriate subcontractors in estimating these costs.

3.3.3 Interference with Pipeline Operations

Depending on the ELD system and the pipeline under consideration, ELD deployment might also lead to some degree of interference with the pipeline's typical operational activities. The annual cost associated with interference with pipeline operations is estimated by first considering possible operational activities that might be impacted by the physical presence of ELD sensors and any supporting ELD infrastructure (communication cables, solar panels, interrogator units, battery packs, etc.). Integrity digs and pipeline repairs are the most likely operational activity to be impacted by the presence of ELD; however, other operational activities are also possible.

4. BENEFIT CHARACTERIZATION

4.1 Overview

This section provides guidance on evaluating and quantifying the benefits that can be achieved by ELD implementation for each of the preferred deployment configurations that were identified in Section 2. A benefit characterization is a required input for the formal CBA described in Section 5.

ELD implementation has the potential to provide benefits in two ways:

1. By reducing the duration of pipeline releases, thereby reducing the amount of product that is lost to the environment in the event of a leak or break; and
2. By preventing pipeline leaks or breaks, thereby reducing the potential for product loss and associated fatalities or injuries.

Given the above, the following principal benefit categories have been identified:

- Environmental protection enhancements (based on the potential reduction in the quantity released in the event of line failure);
- Safety enhancements (based on the potential reduction in fatalities and injuries due to a reduction in failures); and
- Reputation enhancements (based on the potential increase in public and regulatory confidence resulting from improved levels of safety and/or environmental protection).

Provided that objectively determined, quantitative measures of the environmental, safety and reputational enhancements achieved by ELD deployment can be estimated, the potential exists to express those enhancement measures in monetary terms. While a reduction in the expected release volume or the expected number of casualties can serve as objective quantitative measures of environmental protection and safety enhancements, respectively, there is no obvious or established means to quantitively gauge the reputation enhancements afforded by improved levels of safety or environmental protection. In addition to being difficult to quantitively measure (and let alone monetize), reputational enhancements are not a significant public concern. On that basis, the guidance provided herein focuses primarily on environmental protection and safety benefits. There may be specific scenarios where one might wish to quantify reputation enhancements in non-monetary terms. For example, reputation enhancements could serve as an additional basis from which to compare multiple alternatives with similar rankings. The subject of using non-monetized benefits, including reputation enhancements, to compare different alternatives in relative terms is addressed in Section 5.

4.2 Environmental Protection Enhancements

4.2.1 Overview

Environmental protection enhancements are based on the expected reduction in release volume that would result from ELD implementation. Estimating the expected reduction in the volume released and converting the resulting value into an equivalent dollar measure of adverse environmental impact avoided requires the following:

- Baseline Release Volume Estimate: The baseline release volume is the expected release volume that would result, given that a release has occurred, assuming no ELD systems are deployed.
- Reduced Release Volume Estimate: The reduced release volume is the release volume that would be expected to result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
- Failure Rate Estimate: The failure rate represents the expected rate of occurrence of pipeline releases over a given time period (typically one year) and over a particular length of pipeline.
- Monetization Models: Monetization models are required to convert the calculated reduction in expected release volume into an equivalent dollar measure of the expected environmental impact reduction achieved.

The expected benefit (expressed in equivalent dollar terms) is obtained by multiplying the failure rate by the difference between the baseline and reduced release volumes, and monetizing the resulting value using the adopted monetization model. This can be expressed mathematically as follows, assuming a simple monetization model, which effectively acts as a constant multiplication factor[9]:

$$\mathrm{ENVIRONMENTAL\ PROTECTION\ BENEFIT} = (\mathrm{V_{BL}} - \mathrm{V_{RED}}) \times \mathrm{R_F} \times \mathrm{R_M} \qquad [4.1]$$

where the baseline and reduced release volume estimates are represented by V_{BL} and V_{RED}, respectively, the failure rate estimate is represented by R_F and the monetization factor is represented by R_M.

[9] In many scenarios, this is appropriate; however, some monetization models involve nonlinear transformations to the baseline and reduced release volumes. Refer to Section 4.2.5 for an example of a nonlinear monetization model.

The following subsections discuss each of these model components in detail and provide general methods for applying them in a benefit calculation. Depending on the benefit calculation approach used, the values obtained using Equation [4.1] might represent:

- Average, or expected, values;
- Individual stochastic realizations; or
- Weighted contributions of overall values.

Different benefit calculation approaches and their relation to the individual model components listed above are discussed at the end of this section (refer to Section 4.2.6).

4.2.2 Baseline Release Volume

The baseline release volume represents the expected release volume, given the occurrence of a pipeline release, absent deployment of the proposed ELD system(s). In the absence of an ELD system, it is assumed that all pipeline releases are eventually detected by either the public, a third-party contractor, a pipeline employee, a CPM system or some other source that is unrelated to the performance of an ELD system. The baseline release volume is estimated by determining the volume of product that will likely escape from a pipeline before it is detected by one of these means. Consistent with this, the two following methods have been identified as possible ways for estimating the baseline release volume, with the most appropriate method depending primarily on the information available and on the environmental benefit calculation approach used (refer to Section 4.2.6).

- Direct methods: With sufficiently detailed data, as well as the appropriate software tools and expertise, it is theoretically possible to directly calculate or model the baseline release volume for a representative range of release conditions. Specific models would be required to accurately predict fluid migration through soil and, if applicable, gas dispersion through the atmosphere. Several computer packages are currently available for predicting the fate and transport of hydrocarbons in soil (1,5). However, these models require specialized expertise and significant computational resources, making them impractical to use for many ELD applications. Further, to estimate baseline release volume, the results from these models would have to be combined with other information, such as expected population density, maintenance and inspection schedules, and CPM capabilities, to estimate at which point a given release is likely to be detected, and how much volume has escaped between that moment and the instant the release began. If performed correctly, this is the most accurate method; however, it requires precise data, and specialized modeling techniques and expertise.
- Inferred methods: Baseline release volume can also be inferred from historical incident data, provided the incident database is sufficiently large and that it is reasonably representative of the pipeline under consideration. This approach is simpler to implement than direct

approaches and doesn't require as much specialized data; however, it might not be as accurate as direct modeling.

Often, the information, the tools or the expertise required to effectively calculate baseline release volume directly is not available. Therefore, it may not always be practical or even possible to estimate baseline release volume using a direct approach. In many cases, the most appropriate approach for calculating baseline release volume will rely on historical incident data. Given this, the guidance provided in this section will focus primarily on estimating baseline release volume using inferred approaches, which rely on historical incident data.[10]

Baseline release volume can either be a random variable defined by a probability distribution or a deterministic single-valued estimate (e.g. the mean or most likely value). Whether to treat baseline release volume as a random variable or a deterministic value largely depends on the adopted benefit calculation approach (refer to Section 4.2.6). With inferred approaches, a random variable representing baseline release volume is obtained by fitting a statistical distribution to a representative sample of applicable incident reporting data. Similarly, a deterministic value representing the average baseline release volume is obtained by calculating a population statistic (mean, median, etc.) from a representative sample of applicable incident data. Whether fitting a statistical distribution or calculating a population statistic, such as the mean, it is important to ensure that the incident data used is reasonably representative of the pipeline under consideration. To this end, it is necessary to filter the incident data appropriately before fitting a distribution to it or calculating a statistic from it. However, it should be noted that excessive filtering could reduce the sample size to the point where it is no longer possible to achieve a good distribution fit or calculate a meaningful statistic. On that basis, it is recommended only to filter the incident data based on data fields that are expected to significantly impact the reported release volume. One approach for determining which data fields to consider is to perform correlation analysis between selected data fields and the reported release volume.[11] Data fields that are strongly correlated with the reported release volume should be filtered to only include entries that are consistent with the pipeline in question, whereas those that are weakly correlated should not be included so as to maximize the amount of available data from which to fit a distribution. To manage the level of effort, correlation analysis should only be performed on data fields that are known to influence or be capable of influencing the reported release volume. Generally, data fields that affect fluid migration and gas dispersion (cover depth, release pressure,

[10] Examples of relevant incident reporting databases, which could be used to inform baseline release volume, include, but aren't limited to, the following: EGIG - European Gas Pipeline Incident Report (6), UKOPA (7), PHMSA Gas Transmission and Gathering Incident Report (8), CONCAWE - Performance of European Cross-Country Oil Pipelines - Statistical Summary of Reported Pillages (9).

[11] More rigorous data exploration and data reduction techniques, such as principal component analysis and regression analysis, could be considered; however, it is important to ensure that the size of the dataset is sufficient to support the application of such methods.

soil properties, ambient meteorological conditions, release type/failure mode, etc.), and detection response time (remote vs. manual isolation valves, elevation profiles, class location, crossings, release type/failure mode, etc.) are expected to also affect reported release volume.

In some cases, it might be necessary to fit separate distributions or calculate separate population statistics for different values of a given data field. For example, if the incident data distinguishes breaks from other releases (leaks, punctures, etc.), and if there is a notable difference between the release volumes associated with breaks and other releases, then it might be important to separate the baseline release volume into two separate variables, one representing the release volume from leaks and another representing the release volume from breaks.[12]

In the absence of meaningful correlations, or in cases where correlation analysis cannot be performed due to resource or time constraints, it is recommended that the following important data fields be considered as these are likely to affect reported release volume to some degree:

- The transported substance type (crude oil, natural gas, gasoline, etc.);
- Whether the pipeline is deployed on-shore or off-shore;
- Whether the pipeline resides above or below ground; and
- The reported failure mode (i.e. leaks vs. breaks).

In addition to ensuring that the incident database is reasonably representative of the pipeline under consideration, it is also important to consider the possible effect of complementary leak detection systems, such as CPM. When considering the possible effects of CPM or other complementary leak detection systems, there are two possible approaches. The first approach is to account for the effect of CPM implicitly in the incident reporting data. This involves filtering the incident data according to whether a CPM system is, or is expected to be, installed on the pipeline under consideration. For instance, if the pipeline under consideration is not expected to have a CPM system deployed, then the incident data should be filtered such that it only reflects entries which were not confirmed to have been detected with CPM. Conversely, if the pipeline under consideration is expected to have CPM deployed, then the incident data should be filtered such that it reflects only entries which were confirmed to have a CPM system deployed. This approach requires the database to contain data fields indicating both whether CPM was deployed and, if so, whether it was the basis for detection. This approach is simple to implement; however, it makes the implicit assumption that CPM performance is representative of the aggregated performance

[12] Note that the criteria by which to distinguish leaks from breaks should be defined. The criteria could be based on the release rate (either absolute or relative to the pipeline flow rate), hole size and geometry, or some combination thereof.

of the CPM systems as reported in the incident database. It may not accurately reflect the true performance of the actual CPM system under consideration. If CPM performance is expected to differ significantly from that of typical CPM systems, as represented in the incident database, or if CPM performance is not accurately represented by the data contained within the database, then this approach may not be appropriate. It is also important to consider potential biases in the way CPM is reported in the incident database. For example, leaks caused by a third-party might have a higher probability of being detected by the third-party who caused the accident, rather than by a CPM system. This should not be interpreted to mean that CPM systems are not effective at detecting these releases. Drawing such conclusions from the incident data could potentially lead to inaccurate CPM performance estimates.

The other approach is to account for the effect of CPM explicitly by calculating the expected release volume for releases that exceed the CPM detection threshold based on the expected performance specifications of the CPM system being considered. This approach requires accurate information about the CPM system and its expected performance when it is deployed on the pipeline under consideration, as well as information about the pipeline's operation (i.e. the expected frequency and duration of shut-in events during which CPM is non-functional or has reduced performance). This approach also requires information about the release rates of the reported releases. If such information is not available, it may be necessary to make assumptions about the expected release rates or to obtain additional information (i.e. hole size distributions) from other information sources or incident databases. If properly executed, this approach tends to be more accurate than the first approach and is able to provide a more tailored representation of the true performance of the CPM system being considered. In applying the direct approach, it is important to first filter the incident database to only include releases that were not detected with CPM. The baseline release volume distribution can then be adjusted by considering a variety of representative releases and calculating the estimated reduction in release volume that would be expected if the CPM system in question were deployed and functional. It might be necessary to consult with the CPM technology vendor to acquire accurate performance data. Alternatively, for existing pipelines, it might also be possible to base future CPM performance on historical CPM performance data from the pipeline under consideration.

4.2.3 Reduced Release Volume

The reduced release volume represents the release volume that would arise, given a release has occurred, assuming a particular ELD system is installed in a particular deployment configuration. Because ELD systems are relatively new and pipeline releases relatively rare, historical incident data describing reduced release volumes either doesn't exist or is critically limited. Accordingly, reduced release volume cannot be reliably inferred from historical data. The only viable approach is to estimate it directly using appropriate models and assumptions.

ELD systems are able to alert pipeline operators of certain releases (i.e. those that fall within the ELD system's detection range) sooner than would otherwise be possible, thereby reducing the expected duration and volume of these releases. Reduced release volume is therefore based on an ELD technology's overall ability to reduce the time required to detect pipeline releases (i.e. reduced detection time).[13] On that basis, reduced release volume is quantified by first identifying releases (or the expected proportion of releases) that fall within the ELD system's detection range (i.e. detectable releases). The associated release rates of the detectable releases are then calculated and multiplied by the overall response time (i.e. the ELD response time plus the operator response time). Depending on the adopted benefit calculation approach, the resulting volumes are either averaged or aggregated and fit to an appropriate statistical distribution (refer to Section 4.2.6). Determining whether or not a release is detectable and calculating the expected release volume of detectable releases requires information about the release magnitude, the ELD detection threshold, the ELD response time, the operator response time and the release rate. These topics are addressed below:

ELD Response Time

The ELD response time is defined as the time between the onset of a leak, and the moment at which point the leak has been discovered by the ELD system and communicated to the pipeline operator. ELD response time is a function of the ELD system's sensing mechanism, as well as the relevant pipeline attributes along the pipeline section being evaluated.[14] ELD response time, therefore, varies along the pipeline and changes according to the ELD sensor deployment configuration (refer to Section 2). Depending on the information made available by the ELD technology vendor, it might be necessary to perform additional numerical modeling, bench-scale testing, full-scale testing or field-scale testing to properly characterize the ELD system's expected response time given specific pipeline attributes for each of the defined sensor deployment configurations and pipeline segments being evaluated. ELD response time is also a function of the leak characteristics (i.e. hole size and driving pressure). For example, consider an ELD system with a detection threshold of x defined in terms of minimum detectable leak rate. This system might be able to detect a leak that only narrowly exceeds the detection threshold in time, y; however, a larger leak, with a leak rate that greatly exceeds the detection threshold of say $2x$, could be detected in a shorter time of $y/2$. The exact mathematical relationship describing response time as a function of specific leak characteristics for a particular sensor deployment configuration and

[13] Environmental benefits resulting from encroachment detection contribute to a reduction in the assumed failure rate, rather than a reduction in the expected release volume, because encroachment detection tends to prevent breaks altogether, rather than reduce the volume released. Therefore, the benefits associated with encroachment detection are addressed in Section 4.2.4).

[14] Bussière et al. (1) provide a basis for determining which pipeline attributes are most relevant to ELD performance given a particular sensing mechanism.

in a particular application environment is not always known by the ELD technology vendor, and may need to be obtained through independent modeling or testing. In the absence of this information, an approximate, fixed response time could be used; however, to achieve the most representative results, a variable response time should be considered when the required information is available.

Operator Response Time

Operator response time is defined as the time it takes the operator to respond to an ELD leak alarm and effectively stop the leak. Accurately characterizing operator response time requires information about: the nature of the ELD alarm itself (degree of supervisory control and data acquisition (SCADA) integration, personnel alerted, communication protocol etc.); alarm management strategies employed by the operating company; and certain pipeline attributes, specifically whether or not sections can be remotely isolated (i.e. shut in), the pipeline elevation profile, and the proximity and the level of accessibility to responders.

ELD Detection Threshold

The ELD detection threshold represents the smallest detectable leak that an ELD system can reliably detect without exceeding a prescribed false alarm rate. It is often defined in terms of well-known flow parameters, such as leak rate, but it can also be defined in terms of some combination of parameters (e.g. $p^n \times d^m$ where p is the release pressure, d is the orifice diameter and n and m are exponents). ELD detection threshold depends on the technology type and should be provided by the ELD technology vendor. In the absence of accurate information describing the ELD system's detection threshold, it might be necessary to obtain it by through additional experimental evaluations or numerical modeling.

Release Rate

Release rate is the volumetric or mass flow rate of a given release. It is used in the calculation of the release volume for detectable releases. It can be expressed as a fixed value representing the average release rate over time or as a time varying value, which changes with evolving flaw geometry and pipeline operating conditions. Calculation of release rate requires representative distributions of expected hole sizes, driving pressures and other relevant parameters depending on the adopted leak rate expression.

Leak rate is primarily a function of the driving pressure, the hydraulic properties of the product, the orifice size and the orifice geometry. The exact relationship depends primarily on the phase composition of the product (i.e. single-phase liquid, single-phase gas, or two-phase), as well as the orifice shape (circular, rectangular etc.) (9,11,12,13). For example, a simplified expression for estimating the leak rate of single-phase liquid flow through a circular orifice is given by:

$$Q = \frac{\pi C_d d^2}{4}\sqrt{\frac{2p}{\rho}}$$

where C_d is the discharge coefficient, p is the driving pressure, d is the orifice diameter and ρ is the product density. Different leak rate expressions are required for characterizing different flow regimes and often multiple expressions (or variations of them) can be used for the same flow regime. There are several examples of widely accepted leak rate models for single- and multi-phase flow through cracks in the literature (9,12,13). Some leak rate models are deemed more accurate, but might require additional computational resources, whereas others might be less accurate, but more computationally efficient. Therefore, in identifying an appropriate expression to use for the leak rate calculation, it is important to consider not only the expected flow regime, but also the required level of accuracy and the available computational resources.

4.2.4 Failure Rate

Failure rate is the expected probability of a pipeline release (i.e. failure) occurring within a prescribed time period (typically one year) over some fixed length of pipeline. There are several approaches for estimating the expected failure rate of a pipeline. The different approaches are generally classified as being either qualitative or quantitative in nature, where the estimated failure rate is measured on subjective and objective scales, respectively. In estimating benefits for the purpose of conducting a CBA, the desire is to objectively characterize potential benefits in equivalent dollar terms. To this end, the guidance provided in this section will focus on quantitative approaches for estimating failure rate.

The catalogue of available, and generally accepted, quantitative approaches for estimating pipeline failure rates can be classified into the following three categories (14):

- Subject matter expert (SME) opinion: Failure rates are estimated by converting SME opinion into quantified probabilities. SME opinion is often used in qualitative approaches where the failure rates are expressed as index values rather than quantified probabilities. The accuracy of this approach depends on the experts chosen and the method used to elicit their input.

- Historical failure data: Failure rates are estimated based on available historical incident databases. In essence, the overall pipeline failure rate estimate is calculated by dividing the number of incidents occurring in a given time period (i.e. one year) by the exposure (i.e. the total mileage of pipeline over which the incidents are aggregated) and multiplying by some system-specific modifier to reflect system-specific attributes.

- Engineering models and reliability analysis methods: Failure rates are estimated based on detailed engineering models, as well as statistical data, to characterize the associated input parameters. This is the preferred failure rate estimation approach if the overall benefit calculation approach is probabilistic in nature (refer to Section 4.2.6.2).

With SME opinion and historical failure data approaches, it might be appropriate to estimate different failure rates for different sections of the pipeline if the sections are believed to have substantially different attributes. It might also be necessary to obtain separate failure rates for different failure modes (i.e. leak vs. break).

Failure rate is also affected by ELD technologies with the ability to prevent releases. Release frequency reduction is predominantly achieved through additional ELD system functionality, such as encroachment detection, whereby the ELD system notifies operators of potential unauthorized third-party encroachment activities that risk damaging the pipeline. For these scenarios, the potential benefit resulting from this added functionality is quantified by first estimating the expected proportion of releases, which are believed to be caused by encroachment activities, then estimating the expected proportion of encroachment activities that can be detected and prevented by the ELD system in question. The resulting environmental protection benefit is then quantified by considering the release volume that would result if the preventable, encroachment induced releases were to occur. The quantified (non-monetized) environmental benefit resulting from encroachment detection is expressed mathematically as follows:

$$\mathrm{ENCROACHEMENT\ DETECTION\ ENVIRONMENTAL\ BENEFIT} = \mathrm{R_{ENC}} \times \mathrm{V_{ENC}} \quad [4.2]$$

where R_{ENC} is the expected rate of release events that are likely to be prevented with encroachment detection (i.e. expressed in prevented breaks per mile-year), and V_{ENC} is the expected release volume that would result should the preventable releases occur. The encroachment detection benefit in Equation [4.2] can then be incorporated into the overall (non-monetized) environmental benefit by combining Equation [4.2] with selected terms from Equation [4.1] as follows[15]:

$$\mathrm{OVERALL\ ENVIRONMENTAL\ BENEFIT} = (\mathrm{V_{BL}} - \mathrm{V_{RED}}) \times \mathrm{R_F} + \mathrm{R_{ENC}} \times \mathrm{V_{ENC}} \quad [4.3]$$

Estimating the terms from Equation [4.2] requires information about the ELD system's encroachment detection capabilities in different soil environments, with different background noise levels and for different types of encroachment activities (human footsteps, mechanical digging, vehicle driving, etc.). This information can be supplied by the ELD technology vendor, provided they are able to provide documentation to support their performance claims. It could also be obtained through an appropriately designed field-scale testing program.

[15] It is important to note that, depending on the exact benefit calculation approach used, the values in Equation [4.3] might represent average, or expected, values; individual stochastic realizations; or weighted contributions of overall values (refer to Section 4.2.1).

It is acknowledged that breaks can also be prevented through the leak-before-break (LBB) concept whereby certain leaks are detected with ELD before they evolve into breaks. Quantifying the potential effect of LBB on break frequency reduction requires a probabilistic environmental benefit calculation approach (refer to Section 4.2.6), as well as structural reliability models and representative inline inspection (ILI) data. It may, therefore, not be possible to quantify break reduction via LBB in all cases. Quantifying the effect of LBB on break frequency reduction involves calculating the time to failure for each reported and assumed flaw from an ILI report. For each flaw, two time-to-failure values are calculated: 1) time to the first failure mode (i.e. leak); and 2) time to the second failure mode (i.e. break). A break is said to be preventable if the total volume released between the first and second failure modes[16] is less than the baseline release volume. The quantified (non-monetized) environmental benefit, resulting from LBB, is expressed mathematically as follows:

$$\mathrm{LBB\ ENVIRONMENTAL\ BENEFIT} = \mathrm{R_{LBB}} \times \mathrm{V_{LBB}} \qquad [4.4]$$

where R_{LBB} is the expected rate of break events that are likely to be prevented with LBB (i.e. expressed in prevented breaks per mile-year) and V_{LBB} is the expected release volume that would result should the preventable breaks occur. The LBB benefit in Equation [4.4] can then be incorporated into the overall (non-monetized) environmental benefit by combining Equation [4.4] with selected terms from Equation [4.1] as follows[17]:

$$\mathrm{OVERALL\ ENVIRONMENTAL\ BENEFIT} = (\mathrm{V_{BL}} - \mathrm{V_{RED}}) \times \mathrm{R_F} + \mathrm{R_{LBB}} \times \mathrm{V_{LBB}} \qquad [4.5]$$

The API standard, API 579-1/ASME FFS-1 Fitness-for-service, provides additional guidance for applying the LBB concept in fitness-for-service applications (15).

4.2.5 Monetization

This section provides guidance on converting the expected release volume reduction into an environmental protection enhancement measure that is expressed in equivalent dollar terms.

There are several well-established and widely accepted approaches for quantifying the environmental and socioeconomic impacts associated with greenhouse gas (GHG) emissions. In contrast, environmental and socioeconomic impacts associated with liquid spills from

[16] The volume released between failure modes should account for the ELD and operator response times.
[17] It is important to note that, depending on the exact benefit calculation approach used, the values in [4.5] might represent average, or expected, values; individual stochastic realizations; or, weighted contributions of overall values (refer to section 4.2.1).

hydrocarbon pipelines are less well understood and the approaches for quantifying such impacts differ significantly from those used for quantifying impacts associated with GHG emissions. In this light, different approaches are recommended depending on whether the dominant environmental threat associated with the transported substance relates to GHG emissions or environmental damage resulting from exposure to persistent liquids. The following subsections provide guidance on estimating environmental protection enhancement measures associated with these two categories of environmental impact.

4.2.5.1 Greenhouse Gas Emission Impacts

For transported substances that consist of known GHGs (i.e. carbon dioxide and methane), the recommended approach for calculating enhancement measures involves estimating the social cost of carbon (SCC). The SCC is intended to be a wide-ranging estimate of the net climate change damages likely to be caused by increased emissions of a particular GHG by some incremental amount (typically by one metric tonne). The damages may be related to changes in net agricultural productivity, human health, increased flood risk and the associated property damages, as well as changes in heating and air conditioning costs. The SCC is frequently used by many world governments and is required by the US federal government as part of CBA for significant regulations and other actions.

In 2009, the US government convened the Interagency Working Group on the Social Cost of Greenhouse Gasses (IWG) to develop SCC estimates for carbon dioxide (i.e. SC-CO2)[18] for use in federal regulatory analysis. The IWG SCC estimates were derived through the use of so-called integrated assessment models (IAMs). The IWG reportedly makes use of three widely cited and extensively peer-reviewed IAMs to make SCC estimates (DICE, FUND and PAGE). For specific details relating to the derivation of the IWG's 2010 SCC estimates, refer to the first IWG document titled: "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, 2010" (16). In the years since 2010, the IWG has updated their original SCC estimates a number of times to reflect improvements in the IAM models, as well as advancements in climate science research (17).

Carbon dioxide is the most prevalent GHG emitted into the atmosphere and, therefore, many SC-CO2 estimates can be found in climate economics literature. However, far fewer estimates of the social costs of other GHGs, such as CH_4 and NO_2, have been published. The global warming potential (GWP) approximation provides a means of converting a particular GHG into a CO_2

[18] To differentiate between the social cost of different GHGs, nomenclature of the form "SC-GHG" has been adopted, where GHG is replaced with the chemical symbol representing the specific greenhouse gas for which social costs are being considered (e.g. SC-CO2 represents the social cost of carbon dioxide, whereas SC-CH4 represents the social cost of methane).

equivalent, which can then be valued using available SC-CO2 estimates (18). However, using GWP to value the damages of non-CO_2 GHGs is not ideal because, while the GWP does characterize non-CO_2 GHGs by their potential to absorb infrared radiation over a given time frame (typically a 100-year period), it does not account for the temporal pathway of their impact on radiative forcing. Furthermore, GWP does not accurately capture physical impacts other than temperature change, which can also vary across different GHGs (19). In light of these limitations, an addendum to IWG document "Technical Support Document on Social Cost of Carbon for Regulatory Analysis under Executive Order 12866" was published in 2016, in which SC-CH4 and SC-N2O are estimated directly using IAMs (20).

In March of 2017, an executive order was signed which effectively disbanded the IWG and withdrew its guidance. However, the IWG addendum (20) is still believed to be the best source for up-to-date and broadly accepted SCC estimates. The 2016 IWG estimates were arrived at through a transparent, rigorous and peer-reviewed process and are the only estimates that are endorsed by the National Academy of Sciences, Engineering and Medicine (NAS). On that basis, until better SCC estimates are published, the recommended approach for estimating environmental enhancement measures associated with ELD implementation involves using the 2016 IWG SCC estimates.[19]

An important consideration when applying SCC values relates to the discount rate. IWG publishes average SCC values for 5%, 3% 2.5% discount rates, as well as a 95th-percentile estimate for the 3% discount rate, which is intended to represent costs associated with catastrophic but unlikely outcomes. Discounting is later applied to all benefits and costs (refer to Section 5); therefore, in order to avoid double discounting environmental benefits, it is recommended that non-discounted SCC values (i.e. SCC values with a discount rate of 0%) be used. However, IWG does not currently publish SCC estimates for a 0% discount rate; it might, therefore, be necessary to modify the published SCC values such that an effective discount rate of 0% is used. This can be accomplished by rearranging the discount rate expressions (see Equations [5.1] to [5.5] provided in Section 5.2.4).

Because SCC values tend to vary with time[20], the year in which potential releases are expected to occur should be taken into account if such information is available. However, depending on the approach used (refer to Section 4.2.6), information about when a release is expected to occur

[19] Note that the 2016 estimates are expressed in 2016 dollars. If used in the discussed CBA, the estimates should be inflated to present-day dollars.

[20] SCC estimates tend to increase over time for the following reasons: 1) future emissions contribute to larger incremental damages as the stress on physical and economic systems increases in response to increased climatic change; and 2) damages, and correspondingly SCC values, are proportional to gross domestic product (GDP), which increases over time.

might not be available and a temporal release distribution must be assumed. The topic of distributing benefits in time is addressed in detail in Section 5.2.3.

4.2.5.2 Other Environmental Impacts

For products that remain in a liquid state following release and which can persist in the environment, an alternative approach is required. While much work has been published on converting the impact of GHGs into equivalent dollar terms, there are limited credible measures of the environmental impact associated with liquid spills from hydrocarbon pipelines. One possible approach is based on previous work by Stephens and Etkin (21) in which a model capable of assessing the combined socioeconomic and environmental impact of low vapor pressure (LVP) hydrocarbon liquid product spills from onshore transmission pipelines was developed. In this model, the following spill impact formula is proposed:

$$C = \beta V^{\alpha} \qquad [4.6]$$

where β is a location factor[21] reflecting the damage sensitivity and importance of the environment affected by the release, V is the release volume and α is the so-called impact attenuation factor, which characterizes the degree of proportionality between the magnitude of the of spill impact and the total volume spilled. Stephens and Etkin propose an impact attenuation factor of 0.8, which indicates that the magnitude of release impact per unit volume released decreases with increasing release volume. Depending on the approach used (refer to Section 4.2.6), the use of an impact attenuation factor could potentially lead to artificially high monetized benefit values.[22]

The results obtained with Equation [4.6] are meant to reflect spill impacts in relative terms. Calculating the absolute spill impact therefore involves multiplying the relative spill impact obtained in Equation [4.6] by an additional factor, c_r, representing the dollar cost equivalent of the spill impact associated with a reference spill involving a specified release of a given product in a specific location.

[21] Recommended location factors for LVP hydrocarbon liquid pipelines are provided in Stephens and Etkin (21).

[22] Applying an impact attenuation factor to fixed-point average values, as would be done in a deterministic approach, risks overestimating the benefit, especially in cases where the variance of the underlying statistical distributions describing the population of release volumes is large. It is therefore recommended to limit the use of the impact attenuation factor to probabilistic and hybrid approaches only (refer to Section 4.2.6).

4.2.6 Environmental Benefit Calculation Approaches

Different approaches can be used for combining the listed model components (i.e. baseline release volume, reduced release volume, failure rate and monetization model) to estimate the environmental protection benefit. It is suggested that most approaches can be classified as deterministic or probabilistic approaches, or hybrid approaches that combine elements of the deterministic and probabilistic approaches. The following subsections discuss each type of approach.

4.2.6.1 Deterministic Approaches

In deterministic approaches, both the baseline release volume and the reduced release volume are treated as constant values. The release volume reduction is simply the arithmetical difference between these two quantities multiplied by the overall failure rate. It might be appropriate to divide the pipeline, or pipeline segment, of interest into discrete sections and to use different baseline release volumes, reduced release volumes and failure frequencies settings for each section.

With deterministic approaches, accounting for CPM performance is generally limited to methods in which the effects of CPM are implicitly accounted for in the incident reporting data. In this way, CPM performance is accounted for in the baseline release volume. If more accurate representations of CPM performance are required, it might be necessary to adopt a probabilistic or hybrid approach.

Implementation of deterministic approaches tend to be straightforward and only require relatively simple input data. However, approaches of this nature are generally perceived to be less accurate than comparable probabilistic approaches because they tend to make simplifying assumptions about certain, potentially important, parameters and are not well equipped to account for the uncertainty inherent in the input parameters. Furthermore, they are not well suited to nonlinear monetization models. Accordingly, caution should be exercised when using nonlinear monetization models, such as the one outlined in Section 4.2.5.2, with deterministic approaches. Such methods should, therefore, only be relied upon to make rough, order of magnitude estimates. Where more accuracy is required, a probabilistic or hybrid approach is generally more appropriate.

4.2.6.2 Probabilistic Approaches

With probabilistic approaches, potential releases are based on reported or assumed flaw measurements (i.e. from an ILI report). In essence, each reported or assumed flaw is assigned a baseline release volume, a reduced release volume value, an estimated failure time, failure mode (i.e. leak or break) and failure probability. These quantities are calculated by performing repeated deterministic calculations on a large number of random realizations from the baseline release volume distribution and other random variables. The deterministic calculations are based on the general methodologies outlined in the previous subsections, as well as other structural reliability models, to predict the evolution of the reported and assumed flaws in time.

The specific deterministic calculations and random variables considered might differ between probabilistic approaches; however, in all cases, a probability-weighted monetized-benefit value is calculated for each of the reported or assumed flaws with the overall monetized benefit being the sum of the of these individual values. Because failure probabilities are calculated for each of the reported or assumed flaws, the failure rate is implicitly accounted for and, therefore, does not need to be calculated or inferred, as is the case with deterministic and hybrid approaches.

If the ELD system in question affords the ability to detect encroachment events, then the reduced release volume associated with each flaw must be adjusted to account for the possible effect of release prevention via encroachment detection. Fundamentally, this consists of determining whether a given release is likely to be prevented by encroachment detection, then calculating the volume that would have been released had the event not been prevented with encroachment detection. This requires additional information about the ELD system's encroachment detection capabilities, as well as data describing the likelihood of a detected encroachment event being successfully prevented.

Probabilistic approaches use advanced structural reliability models and detailed ILI data to directly predict failure modes, time of failure, release rates and failure probabilities for reported or assumed flaws on the pipeline. Probabilistic approaches are generally more accurate than comparable deterministic approaches; however, they require more specialized data and the analysis tends to be more complex and computationally demanding.

4.2.6.3 Hybrid Approaches

Hybrid approaches combine elements of both the deterministic and probabilistic approaches. The baseline release volume, the reduced release volume and the failure rate are fixed-point constant values. However, unlike deterministic approaches, these values are calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variables. Hybrid approaches differ from probabilistic approaches in that the calculations are not based on reported or assumed flaws and, therefore, structural reliability models and ILI data are generally not required. Rather, they are based on assumed random variables (hole size distribution, release pressures, etc.) inferred from historical incident data. As a result, it is not possible to directly estimate the temporal distribution of failures; as with deterministic approaches, this must be assumed later for discounting purposes (refer to Section 5.2). Similarly, the failure rate is not implicitly accounted for and must be estimated later with a separate process (refer to Section 4.2.4).

If the ELD system in question affords the ability to detect encroachment events, then the reduced release volume must be adjusted to account for the possible effect of break prevention via encroachment detection. Fundamentally, this consists of determining whether a given release is likely to be prevented by encroachment detection, then calculating the volume that would have been released had the event not been prevented with encroachment detection. This requires additional information about the ELD system's encroachment detection capabilities, as well as data describing the likelihood of a detected encroachment event being successfully prevented.

Hybrid approaches are simpler to implement compared to probabilistic methods, but are not capable of directly predicting time of failure, failure modes and failure probabilities; these values must be calculated or inferred through a separate process later.

The benefit calculation approach used in the framework demonstration exercise employs a hybrid approach. Further details regarding implementing a hybrid approach for calculating environmental benefits are provided in the demonstration exercise outlined in Appendix A.

4.3 Life Safety Enhancements

4.3.1 Overview

Life safety enhancements are based on the expected reduction in fatalities and injuries that would result from ELD implementation. Estimating the expected reduction in fatalities and injuries, and converting those estimates into an equivalent dollar measure of the value of preventing these losses, requires the following:

- Baseline Fatality and Injury Estimate: The baseline fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming no ELD systems are deployed.
- Reduced Fatality and Injury Estimate: The reduced fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
- Failure Rate Estimate: The failure rate represents the expected rate of occurrence of pipeline releases over a given time period (typically one year) and over a particular length of pipeline.
- Monetization Models: Monetization models are required to convert the calculated reduction in expected fatalities and injuries into a dollar equivalent.

The expected benefit (expressed in equivalent dollar terms) is obtained by multiplying the failure rate by the difference between the baseline and reduced fatality and injury estimates, and monetizing the resulting value using the adopted monetization model. This can be expressed mathematically as follows, assuming a simple monetization model, which effectively acts as a constant multiplication factor[23]:

$$\text{LIFE SAFETY BENEFIT} = (FI_{\text{BL}} - FI_{\text{RED}}) \times \text{R}_{\text{F}} \times \text{R}_{\text{M}} \qquad [4.7]$$

where the baseline and reduced fatality and injury estimates are represented by FI_{BL} and FI_{RED}, respectively, the failure rate estimate is represented by R_F and the monetization factor is represented by R_M.

The following subsections discuss each of these model components in detail and provide general methods for applying them in a benefit calculation. Depending on the exact benefit calculation approach used, the values in Equation [4.7] might represent:

- Average, or expected, values;
- Individual stochastic realizations; or
- Weighted contributions of the overall values

Different benefit calculation approaches and their relation to the individual key components listed above are discussed at the end of this section (refer to Section 4.3.6).

4.3.2 Baseline Fatality and Injury Estimate

The baseline fatality and injury estimate represents the expected number of fatalities and injuries that would result from a pipeline release, absent deployment of the proposed ELD system. The recommended approach for estimating the baseline fatality and injury rate consists of using appropriate quantitative consequence models to estimate the expected life safety impact (i.e. number of fatalities and injuries) that would result from a given pipeline failure. Such models are used in quantitative pipeline risk assessments to quantify the expected life safety impact resulting from pipeline failures in specific areas.

The use of consequence models to estimate the baseline fatality and injury rate requires information about the expected releases, as well as the areas in which the releases are expected to occur. In addition to release-specific parameters, such as the expected release rate, driving pressure and orifice geometry (refer to Sections 4.2.2 and 4.2.3 for guidance on estimating these

[23] In many scenarios, this is appropriate; however, some monetization models involve nonlinear transformations to the baseline and reduced fatality and injury rates.

parameters), additional data might be required by the consequence models. Such data might include, but is not limited to, the following (14):

- Pipe geometry – e.g. wall thickness, diameter;
- Pipeline ROW attributes – e.g. population density, soil properties, location class, depth of cover, ROW activity level, crossings, elevation profile, local meteorological conditions; and
- Properties of the transported substance – e.g. specific heat ratio, molecular weight, temperature, sonic velocity, lower flammability limit (LFL).

Different consequence models are required depending on the underlying hazard categories and different hazard categories are associated with different pipeline substances. Therefore, to assist with the selection and implementation of appropriate consequence models, guidance is provided for identifying appropriate hazard categories depending on whether the substance is classified as a flammable gas, a high vapor pressure (HVP) liquid or a flammable LVP liquid. The key hazard categories being considered are as follows:

- Thermal radiation,
- Toxicity,
- Asphyxiation, and
- Overpressure.

Thermal radiation effects could occur due to the following: fireballs or jet fires resulting from the release of a flammable gas, such as natural gas; flash fires caused by the release of HVP liquids, such as liquified propane; and pool fires caused by the release of flammable LVP liquids, such as gasoline. The remaining hazard categories (i.e. toxicity, asphyxiation and overpressure), result from the release of HVP liquids.

Examples of widely used and generally accepted consequence models for each of the identified substance categories are summarized as follows (14):

- <u>Flammable gas - thermal radiation (jet fires):</u>
    - o The potential impact radius (PIR) model proposed by Stephens et al. (22) can be used to estimate the zone influenced by the thermal effects caused by jet fires. This model is simple to implement and is, therefore, well suited to probabilistic and hybrid benefit calculation approaches (refer to Section 4.3.6).
    - o Other models are available as proprietary software packages, e.g. PIPESAFE, referenced in BS PD 8010-3 (23); and DNV PHAST (24). These models are more detailed than the discussed PIR model and consider meteorological information. This potentially makes

them more accurate, but also more complicated to implement, and, therefore, not well suited to probabilistic and hybrid benefit calculation approaches.

- HVP liquids – thermal radiation (flash fires), toxicity and overpressure:
  - General purpose consequence modeling software recommended by the International Association of Oil and Gas Producers (25) include CANARY by Quest consultants, PHAST by DNV GL, EFFECTS by TNO, and TRACER by Safer Systems.
  - The International Association of Oil and Gas Producers (25), as well as the Norwegian Standard NORSOK Z-13 Annex F (26), provide detailed guidelines for numerical modeling with computational fluid dynamics (CFD).
- LVP liquids – Thermal radiation (pool fires):
  - Pool fires are also addressed by the proprietary software packages and CFD models listed above for HVP liquids.

Detailed examples illustrating the application of thermal radiation consequence models are provided in the literature. Stephens et. al. (27) outline an example application of quantitative risk assessment on an underground gas storage well subject to periodic well entry. In this example, the gas release rate was used in combination with a modified version of the PIR model proposed by Stephens et al. (22) to estimate the extent of the thermal radiation hazard zone that would result from an ignited gas release, as well as the chance of fatality as a function of distance from the leak source (i.e. the wellhead). In another example application, Nessim et. al. (28) calculate the number of fatalities resulting from exposure to heat emitted from a gas fire from a natural gas pipeline failure.

In calculating the baseline fatality and injury rate, it is important to consider the possible effect of complementary leak detection systems, such as CPM, specifically the effect they might have on the estimated baseline fatality and injury rate. Fatalities and injuries are relatively rare; therefore, the effect of CPM on the baseline fatality and injury rate is best estimated explicitly, as opposed to implicitly in the historical incident data (refer to Section 4.2.2). This requires accurate information about the CPM system and its expected performance when deployed on the pipeline under consideration, as well as information about the pipeline's operation (i.e. the expected frequency and duration of shut-in events during which CPM is non-functional or has reduced performance). It might be necessary to consult with the CPM technology vendor to acquire accurate performance data. Alternatively, for existing pipelines, it might also be possible to base future CPM performance on historical CPM performance data from the pipeline under consideration.

4.3.3 Reduced Fatality and Injury Estimate

The reduced fatality and injury estimate is the fatality and injury rate that would arise, given a release has occurred, assuming a particular ELD system is deployed at a particular sensor location. The recommended approach for estimating the reduced fatality and injury rate is fundamentally indistinguishable from that used in estimating the baseline fatality and injury rates, i.e. it consists of using appropriate consequence models to estimate the expected life safety impact resulting from representative, or expected, pipeline failures. The difference lies in the input data supplied to the relevant consequence models. Specifically, leak duration and release volume are modified to account for the effect of candidate ELD technologies.

To this end, consideration is again given to the ELD system's overall ability to reduce the time required to detect pipeline releases (i.e. reduced detection time).[24] Release duration is simply the combined ELD-operator response time (i.e. overall response time), whereas release volume is quantified by first identifying releases (or the expected proportion of releases) that fall within the ELD system's detection range (i.e. detectable releases). The associated release rates of the detectable releases are then calculated and multiplied by the overall response time (i.e. the ELD response time plus the operator response time). Determining whether a release is detectable and calculating the expected release volume of detectable releases requires information about the release magnitude, the ELD detection threshold, the ELD response time, the operator response time and the release rate. These topics are addressed in Section 4.2.3.

4.3.4 Failure Rate

Failure rate is the expected probability of a pipeline release (i.e. failure) occurring within a fixed time period (i.e. one year) over some fixed length of pipeline. There are several approaches for estimating the expected failure rate of a pipeline (refer to Section 4.2.4).

Failure rate is also affected by ELD technologies with the ability to prevent releases. Release frequency reduction is predominantly achieved through encroachment detection and the LBB concept (refer to Section 4.2.4). The quantified (non-monetized) life safety benefit, resulting from encroachment detection, is expressed mathematically as follows:

$$\text{ENCROACHEMENT DETECTION LIFE SAFETY BENEFIT} = \mathrm{R}_{\mathrm{ENC}} \times FI_{\mathrm{ENC}} \qquad [4.8]$$

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[24] Life safety benefits resulting from encroachment detection contribute to a reduction in the assumed failure rate, rather than a reduction in the expected release duration and volume, because encroachment detection tends to prevent breaks altogether, rather than reduce the release duration and volume. Therefore, the benefits associated with encroachment detection are addressed in Section 4.3.4.

where R_{ENC} is the expected rate of release events that are likely to be prevented with encroachment detection (i.e. expressed in prevented breaks per mile-year) and FI_{ENC} is the expected number of fatalities and injuries that would result should the preventable releases occur. The encroachment detection benefit in Equation [4.8] can then be incorporated into the overall (non-monetized) life safety benefit by combining Equation [4.8] with selected terms from Equation [4.7] as follows[25]:

$$\mathrm{OVERALL\ LIFE\ SAFETY\ BENEFIT} = (\mathrm{FI_{BL}} - \mathrm{FI_{RED}}) \times \mathrm{R_F} + \mathrm{R_{ENC}} \times \mathrm{FI_{ENC}} \qquad [4.9]$$

Estimating the terms from Equation [4.8] requires information about the ELD system's encroachment detection capabilities in different soil environments, with different background noise levels and for different types of encroachment activities (human footsteps, mechanical digging, vehicle driving, etc.). This information can be supplied by the ELD technology vendor, provided they are able to provide documentation to support their performance claims. It could also be obtained through an appropriately designed field-scale testing program.

The quantified (non-monetized) life safety benefit, resulting from LBB, is expressed mathematically as follows:

$$\mathrm{LBB\ LIFE\ SAFETY\ BENEFIT} = \mathrm{R_{LBB}} \times \mathrm{V_{LBB}} \qquad [4.10]$$

where R_{LBB} is the expected rate of break events that are likely to be prevented with LBB (i.e. expressed in prevented breaks per mile-year) and V_{LBB} is the expected release volume that would result should the preventable breaks occur. The LBB benefit in Equation [4.4] can then be incorporated into the overall (non-monetized) environmental benefit by combining Equation [4.10] with selected terms from Equation [4.7] as follows[26]:

$$\mathrm{OVERALL\ LIFE\ SAFETY\ BENEFIT} = (\mathrm{FI_{BL}} - \mathrm{FI_{RED}}) \times \mathrm{R_F} + \mathrm{R_{LBB}} \times \mathrm{FI_{LBB}} \qquad [4.11]$$

The API standard, API 579-1/ASME FFS-1 Fitness-for-service, provides additional guidance for applying the LBB concept in fitness-for-service applications (15).

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[25] It is important to note that, depending on the exact benefit calculation approach used, the values in Equation [4.9] might represent average, or expected, values; individual stochastic realizations; or weighted contributions of overall values (refer to Section 4.3.1).
[26] It is important to note that, depending on the exact benefit calculation approach used, the values in Equation [4.11] might represent average, or expected, values; individual stochastic realizations; or weighted contributions of overall values (refer to Section 4.3.1).

4.3.5 Monetization

This section provides guidance on converting the expected fatality and injury reduction into a life safety enhancement measure that is expressed in terms of equivalent dollars. In quantifying life safety enhancements, consideration is given to the following concepts:

- Value of a statistical life, and
- Value of preventing injuries.

The combined estimate of the value of injuries and fatalities prevented constitutes the overall monetized life safety benefit.

4.3.5.1 Value of a Statistical Life

The value of a statistical life (VSL) is commonly described as an estimate for how much people are willing to pay to reduce their risk of death. More specifically, the VSL reflects a population's average marginal rate of substitution between income and risk of death. Accordingly, VSL is a monetary metric of the mortality risk reduction, rather than the valuation of an identifiable life. VSL is well-known and widely used in CBA, including by various US government agencies that use this metric to evaluate the benefits associated with implementing a particular policy or regulation. It is recommended here as a basis for converting fatality reduction into an equivalent dollar benefit.

Methods to estimate the VSL can be broadly categorized into revealed preference (RP) and stated preference (SP) approaches. RP approaches are based on observing individuals' actual behavior, whereas SP approaches are based on survey techniques in which individuals are directly queried about their preferences (29,30,31).

Original research to determine VSL values is not usually practical (31). Therefore, analysts tend to draw from existing VSL values that have been previously estimated using well-established methods. Example sources of published VSL guidance from selected US federal agencies are listed below:

- United States Department of Transportation (DOT): Guidance on valuing the reduction of fatalities and injuries by regulations or investments has been published periodically by the DOT since 1993. In the years since, the DOT has periodically issued revisions, with the most recent revision to this guidance being issued as a memorandum in 2016 (32).
- The United States Environmental Protection Agency (EPA): EPA (33) and Chestnut et al. (34) did an extensive literature review of VSL studies in which EPA recommends a central risk VSL estimate based on 26 policy-relevant risk VSL studies.

In applying VSL, it is important to ensure that it is updated from the original base year (i.e. the year in which the VSL value was originally calculated or obtained) to a new base year (i.e. the current year or the year in which the CBA takes place). This involves adjusting for inflation and real income changes over the intervening years. Guidance for updating VSL values obtained in earlier years is provided by the DOT (32).

4.3.5.2 Value of Preventing Injuries

Unsurprisingly, the value associated with preventing nonfatal injuries is generally found to be lower than the value associated with preventing fatalities (i.e. VSL). However, nonfatal injuries are usually more common than fatalities and, therefore, should not be ignored if possible.

DOT guidance (32) has established a procedure for valuing prevented injuries based on the current VSL estimate and the maximum abbreviated injury scale (MAIS). The DOT guidance for valuing injuries involves first establishing injury severity levels. Each injury severity level is then assigned a coefficient representing a fraction of a fatality. These coefficients can then be multiplied by the adopted VSL value to obtain the values of preventing injuries associated with the defined injury severity levels.

Depending on the adopted consequence models, it might be more difficult to reliably estimate different injury severity levels. In these scenarios, injuries can be accounted for by pro-rating the expected number of fatalities based on an assumed injury-to-fatality ratio.

4.3.6 Life Safety Benefit Calculation Approaches

As with environmental benefits, different approaches can be used for combining the listed model components (i.e. baseline release volume, reduced release volume, failure rate and monetization model) to estimate the life safety enhancement benefit. Similar to environmental protection enhancements, most approaches can be classified as deterministic, probabilistic or hybrid approaches. The following subsections discuss each type of approach.

4.3.6.1 Deterministic Approaches

In deterministic approaches, both the baseline fatality and injury rate, and the reduced fatality and injury rate are treated as constant values. The fatality and injury rate reduction is simply the arithmetical difference between these two quantities, multiplied by the overall failure rate. It might be appropriate to divide the pipeline, or pipeline segment, of interest into discrete sections and to use different baseline release volumes, reduced release volumes, failure frequencies and monetization model settings for each section.

With deterministic approaches, accounting for CPM performance is generally limited to methods in which the effects of CPM are implicitly accounted for in the incident reporting data. In this way, CPM performance is accounted for in the baseline release volume. Where more accurate representations of CPM performance are required, it might be necessary to adopt a probabilistic or hybrid approach.

Implementation of deterministic approaches tend to be straightforward and only require relatively simple input data. However, approaches of this nature are generally perceived to be less accurate than comparable probabilistic approaches because they tend to make simplifying assumptions about certain, potentially important, parameters and are not well equipped to account for inherent uncertainty in the input parameters. Furthermore, they are not well suited to nonlinear monetization models. Accordingly, caution should be exercised when using nonlinear monetization models, such as the one outlined in Section 4.2.5.2, with deterministic approaches. Such methods should, therefore, only be relied upon to make rough, order of magnitude estimates. Where more accuracy is required, a probabilistic or hybrid approach is generally more appropriate.

4.3.6.2 Probabilistic Approaches

With probabilistic approaches, potential releases are based on reported or assumed flaw measurements (i.e. from an ILI report). In essence, each reported or assumed flaw is assigned a baseline fatality and injury rate, an improved baseline injury and fatality rate, an estimated failure time, failure mode (i.e. leak or break) and failure probability. These quantities are calculated by performing repeated deterministic calculations on a large number of random realizations from relevant random variables. The deterministic calculations are based on the general methodologies outlined in the previous subsections and the discussed consequence models. Probabilistic approaches also require appropriate structural reliability models to predict the evolution of the reported and assumed flaws in time (e.g. API 579).

The specific deterministic calculations and random variables considered might differ between probabilistic approaches, however, in all cases, a probability-weighted monetized-benefit value is calculated for each of the reported or assumed flaws with the overall monetized benefit being the sum of the of theses individual values. Because failure probabilities are calculated for each of the reported or assumed flaws, the failure rate is implicitly accounted for and, therefore, does not need to be calculated or inferred as is the case with deterministic and hybrid approaches.

If the ELD system in question affords the ability to detect encroachment events, then the improved failure and injury rates associated with each flaw must be adjusted to account for the possible effect of break prevention via encroachment detection. Fundamentally, this consists of determining whether a given release is likely to be prevented by encroachment detection, then calculating the number of fatalities and injuries that would have occurred had the event not been prevented with encroachment detection. This requires additional information about the ELD system's encroachment detection capabilities, as well as data describing the likelihood of a detected encroachment event being successfully prevented.

Probabilistic approaches use advanced structural reliability models and detailed ILI data to directly predict failure modes, time of failure, release rates and failure probabilities for reported or assumed flaws on the pipeline. Probabilistic approaches are generally more accurate than comparable deterministic approaches; however, they require more specialized data and the analysis tends to be more complex and computationally demanding.

4.3.6.3 Hybrid Approaches

Hybrid approaches combine selected elements of deterministic and probabilistic approaches. The baseline fatality and injury rate, the reduced fatality and injury rate, and the failure rate are fixed-point constant values. However, unlike deterministic approaches, these values are calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variables. Hybrid approaches differ from probabilistic approaches in that the calculations are not based on reported or assumed flaws and, therefore, structural reliability models and ILI data are generally not required. Rather, the calculations are based on assumed random variables (hole size distribution, release pressures, etc.) inferred from historical incident data. As a result, it is not possible to directly estimate the temporal distribution of failures; as with deterministic approaches, this must be assumed later for discounting purposes (refer to Section 5.2). Similarly, the failure rate is not implicitly accounted for and must be estimated later with a separate process (refer to Section 4.2.4).

If the ELD system in question affords the ability to detect encroachment events, then the reduced fatality and injury rate must be adjusted to account for the possible effect of break prevention via encroachment detection. Fundamentally, this consists of determining whether a given release is likely to be prevented by encroachment detection, then calculating the number of fatalities and injuries that would have occurred had the event not been prevented with encroachment detection. This requires additional information about the ELD system's encroachment detection capabilities, as well as data describing the likelihood of a detected encroachment event being successfully prevented.

Hybrid approaches are simpler to implement compared to probabilistic methods, but are not capable of directly predicting time of failure, failure modes and failure probabilities; these values must be calculated or inferred through a separate process later.

5. COST-BENEFIT ANALYSIS

5.1 Overview

This section provides guidance for combining the calculated costs and benefits into a meaningful evaluation metric, which can be used to objectively compare different ELD deployment alternatives. In performing a cost-benefit analysis, it is recommended that the present-day equivalent dollar value of both the benefits and costs be first calculated using an appropriate discount rate and discounting approach. Then, different methods can be considered for combining the present-day costs and benefits into a cost-benefit measure, which can serve as an objective basis for decision making and deployment configuration ranking. Lastly, it is recommended that a sensitivity analysis be performed to examine how the present-day costs and benefits and, ultimately, the adopted cost-benefit measure change with variations in inputs and assumptions.

5.2 Discounting

Discounting is a process that is used to compare costs and benefits that are incurred at different points in time. Costs and benefits occurring at different times should be adjusted so they reflect their value at a reference point in time, usually the present time. This is especially important if the analysis takes place over extensive time horizons, such as in the case of pipelines. The premise of discounting is based on the principle that people usually prefer to receive goods and services now rather than later (i.e. time preference). Generally, societies are assumed to grow wealthier over time; therefore, discounting also accounts for economic growth. Before discounting can be properly implemented in a CBA, it is important to first establish the following:

- The type of discount rate used (i.e. private or social);
- The temporal distribution of costs (i.e. placing the costs in time);
- The temporal distribution of benefits (i.e. placing the benefits in time); and
- The different discounting approaches.

Each of these topics are addressed in more detail in the following subsections.

5.2.1 Discount Rate

In discounting future costs and benefits, it is important to first determine whether it is more appropriate to use social or private discount rates. When the objective of a CBA is to consider the costs and benefits of a policy or project for society at large, then the social discount rate is the appropriate choice. If, however, the objective of a CBA is to justify an investment opportunity by simply estimating the private cost to the investment provider, then a private discount rate is perhaps more appropriate. While pipelines are typically owned and operated by private agents, it is important to recognize that there is a social cost associated with private agents whose operations have the potential to impact society at large. In the case of ELD implementation on a pipeline asset, most of the potential benefits can be expressed as an expected reduction in the undesirable burden on society (i.e. fatality, injury, environmental damage). In this light, social discounting is believed to be the most appropriate approach for the purpose of conducting CBA for ELD implementation on a pipeline.

5.2.2 Temporal Distribution of Costs

The various costs associated with ELD implementation tend to occur at different times throughout the operational life of the pipeline. It is important to properly place these costs in time with as much accuracy as possible to ensure that they can be properly discounted into present-day dollar equivalents. This section will address temporal placement for costs in each of the cost categories identified in Section 3.

Procurement and Installation

Procurement and installation costs are associated with the purchase of the ELD equipment, as well as the installation and commissioning of the ELD systems. Procurement and installation costs are usually incurred simultaneously; therefore, for the purpose of establishing a temporal distribution of costs, they will be addressed together.

In the case of new construction pipelines, these costs are typically incurred within the first few years (i.e. concurrent with pipeline construction). By contrast, with retrofit deployments (i.e. deployment on an existing pipeline), it might be appropriate to consider ELD deployment at different stages in the pipeline's operating life (e.g. to reduce installation costs, it might be preferred to install ELD only when maintenance or integrity activities are being performed on the pipeline). It is also possible to consider a combination of up-front and staged procurement and installation costs.

Procurement and installation costs represent significant capital investment, and it might be tempting to accrue the costs throughout time for accounting purposes. Accruals are an accounting method that records revenues and expenses when they are incurred, regardless of when the transaction occurs. In characterizing the temporal distribution of procurement and installation costs, it is recommended that accounting accruals be avoided. In CBA, costs and benefits are discounted into the future; therefore, moving costs to different time periods, compared to when the transaction actually occurred, risks misrepresenting the true net present value of that cost.

Operation and Maintenance

Operation and maintenance costs are required to ensure adequate performance over the course of the ELD system's operational life. For the purpose of defining the temporal distribution of these costs, they can be divided into two categories: periodic costs (e.g. scheduled preventative maintenance costs and expected operational costs); and episodic costs (e.g. corrective maintenance costs, repair costs and upgrade costs). Periodic costs occur at regular intervals and are generally easier to place in time compared to episodic costs, which occur at irregular and unpredictable times.

With regard to characterizing the temporal distribution of periodic costs, it is recommended to consult the ELD technology vendors. They should be able to provide guidance for estimating an anticipated preventative maintenance schedule for a given ELD system deployed in a particular location. They should also be able to provide guidance for estimating an anticipated temporal distribution of regular operational costs.

Because episodic costs are usually the result of some form of component or system failure, they cannot be easily anticipated and, therefore, it is more difficult to accurately place them in time. The ELD technology vendor may be able to provide guidance in estimating failure rate for a given ELD system deployed in a particular location. However, it might be necessary to make assumptions regarding the anticipated failure rate over the ELD system's operational life. For example, it might be appropriate to assume that, as the ELD system ages, it will experience more failures and require more repairs, thereby suggesting a higher concentration of episodic costs toward the end of the ELD system's lifespan.

Responding to False Alarms

Costs associated with responding to false alarms are expected to occur periodically over the course of the ELD system's operational life. The temporal distribution of such costs depends on the expected temporal distribution of false alarms. Such information is not usually known ahead of time, but technology vendors might be able to provide some guidance on this subject. Working with the technology vendors, it might be possible to make reasonable assumptions regarding the anticipated frequency of false alarms over the operating life of the pipeline. In certain cases, it might be reasonable to assume that false alarms occur less frequently over time as a result of the ELD system adapting and being better able to distinguish actual leaks from extraneous noise.

Interference with Pipeline Operations

ELD systems can lead to some degree of interference with the pipeline's typical operational activities, thereby incurring additional costs. Placing these costs in time requires information about the distribution of potential pipeline operational activities that might be impacted by either the physical presence of ELD sensors or activities related to the ELD system. Therefore, in addition to identifying these activities, it is also necessary to make assumptions about when they are expected to occur throughout the pipeline's operational life. For example, it might be appropriate to assume that the frequency of pipeline integrity digs will increase as the pipeline ages. Therefore, interference costs related to integrity activities might be distributed such that there is a higher concentration later in time.

If there is not enough information to inform a representative temporal distribution of a particular cost, then the recommendation is to simply assume a uniform cost distribution over the asset's remaining operational life. It should be noted, however, that assuming a uniform cost distribution could: overestimate the overall net present cost value if the expected costs are actually more concentrated later in time, and underestimate the overall net present cost value if the expected costs are actually more concentrated earlier in time.

5.2.3 Temporal Distribution of Benefits

As with costs, the benefits associated with ELD implementation tend to occur at different times throughout the operational life of the pipeline. It is important to properly place potential benefits in time with as much accuracy as possible to ensure that they can be properly discounted into present-day dollar equivalents. In this section, only monetary benefits will be addressed. Non-monetary benefits are not expressed in equivalent dollars and, therefore, are not subject to discounting. Characterizing the temporal distribution of expected benefits is based on the following key considerations:

Evolution of ELD System Performance

An ELD system can only begin to generate benefits once the system is installed and operational. There is likely a period of time during which the system is either being installed, commissioned or calibrated where it is not yet fully operational and, therefore, unable to generate any benefits. This should be considered when placing the expected benefits in time. In a similar vein, there may also be a start-up period during which the system is installed and operational, but its performance is not yet optimized. Depending on the ELD technology and its application environment, this start-up period may or may not exist, and its duration and characteristics might differ. It is recommended to consult with the ELD technology vendor for guidance on this subject. If such information is not available, it might be appropriate to conservatively assume that a start-up period does exist. It might simply be characterized as a period of time (i.e. 1 to 2 years) during which the ELD system's sensitivity is reduced in order to minimize false alarms while the system adapts to the application environment. Alternatively, the assumed start-up period might be characterized by a gradual increase in sensitivity and a corresponding decrease in false alarm rate during some finite time interval (i.e. 4 years). The choice to adopt an assumed start-up period depends on a number of factors, including the ELD system, the application environment and the operator's individual risk tolerance.

Pipeline Failure Rate

In Section 4, it was shown that pipeline failure frequencies, namely that of leaks and breaks, are a key element in quantifying potential benefits resulting from ELD implementation. Therefore, understanding the temporal distribution of pipeline leaks and breaks is required in order to accurately place expected benefits in time.

If ILI data is available and is used in the calculation of the expected benefits, then it is possible to use appropriate feature growth models (i.e. API 579) to predict the time period within which potential failures would occur. The associated benefits are then distributed throughout time on a per failure basis according to the respective leak or break that was used in the benefit calculation. For breaks or, more specifically, prevented breaks, the associated benefit (i.e. the reduction in fatalities, injuries, release volume or a combination thereof) is assumed to be incurred when the break is predicted to occur. Unlike breaks, leaks gradually evolve over extended time periods before being detected. Therefore, to ensure that the associated benefit is properly discounted, its temporal placement should be based on the baseline leak duration. For leaks, the expected benefit (i.e. the reduction in release volume) is therefore assumed to be incurred when the leak would eventually have been detected if ELD were not deployed (the guidance in Section 4.2.2 on establishing a baseline release volume can be useful in estimating a baseline release duration).

If ILI data is not used in the calculation of the expected benefits, then it is not possible to distribute benefits throughout time on a per-failure basis. Instead, it is recommended to assume a representative temporal distribution of leaks and breaks. This can then serve as a basis by which to place benefits in time. The required leak and break temporal distributions could be informed from historical incident data, whereby reported leaks and breaks from several different pipeline vintages are considered and compared to the date in which individual leaks or breaks were reported. The expected benefits associated with a particular failure mode (i.e. leak or break) can then be distributed in time according to the underlying temporal distribution of that failure mode. For example, suppose historical incident data is used to define the following simple temporal distribution of leaks for a given pipeline: $P_{leak} = f(t)$ where P_{leak} is the leak likelihood per mile-year and t is the time in years relative to the pipeline installation date. The pre-discounted expected benefits, which in this example would be based on the expected reduction in release volume for a random leak, can then be distributed in time by multiplying the dollar equivalent values by $f(t)$ for each year of operation.

If there is not enough information to develop a representative temporal distribution of a particular benefit, then the recommendation is to simply assume a uniform benefit distribution over the asset's remaining operational life. It should be noted, however, that assuming a uniform benefit distribution could: overestimate the overall net present benefit value if the expected benefits are actually more concentrated later in time, and underestimate the overall net present benefit value if the expected benefits are actually more concentrated earlier in time.

5.2.4 Discounting Approaches

There are a number of different approaches for discounting future costs and benefits to present-day equivalents. The various approaches do not represent different ways of calculating the benefits and costs; rather, they represent different ways to express and compare the calculated costs and benefits. Common discounting approaches are introduced and discussed below:

Present Value

The present value of an expected array of current and future benefits and costs is calculated by multiplying the benefits and costs in each year by a time-dependent weight, and adding all of the weighted values as follows[27]:

$$PVB = \sum_{t=0}^{n} B_t d_t \qquad [5.1]$$

$$PVC = \sum_{t=0}^{n} C_t d_t \qquad [5.2]$$

where the aggregated present value of current and future benefits is given by *PVB*, the aggregated present value of current and future costs is given by *PVC*, the current year is given by *t*, the duration of the analysis is given by *n*, the total benefit and total cost associated with year *t* is given by B_t and C_t, respectively, and the discounting weights for a given year, *t,* and discount rate, *r*, are given by:

$$d_t = \frac{1}{(1+r)^t} \qquad [5.3]$$

Discounting using the present values approach is likely to be the simplest and most informative discounting method for scenarios where CBA is used to evaluate an immediate investment that offers an array of highly variable future benefits. In many cases, ELD implementation on a pipeline closely resembles this description. However, rather than simply looking at the total present value of the costs and benefits, it may be required to evaluate them on an annualized basis.

[27] The following formulas assume that t=0 designates the beginning of the first period.

Annualized Values

Annualized values represent the non-discounted values at the end of each time period whose present value sum is equivalent to the present value sum of the original array of current and future values. It is calculated for benefits and costs as follows[28]:

$$AVB = PVB\frac{r(1+r)^n}{(1+r)^\alpha - 1} \tag{5.4}$$

$$AVC = PVC\frac{r(1+r)^n}{(1+r)^\alpha - 1} \tag{5.5}$$

where $\alpha = n$ if there are no initial costs at $t = 0$, and $\alpha = (n+1)$ if there are initial costs at $t = 0$.

Annualized values are useful when the alternatives being evaluated (different technologies, different deployment configurations, different pipelines, etc.) have different time horizons.[29] Comparing the net present value between two alternatives with vastly different time horizons could lead to faulty conclusions. However, if evaluated on an annual basis, alternatives with different time horizons can be compared more easily.

In calculating both present values and annualized values, it is important to choose an appropriate time period, t. Time periods are usually one year; however, alternative time periods can be justified if costs or benefits accrue at irregular intervals.

5.3 Evaluation Metric

Once the costs and benefits have been discounted into present-day dollars, it is possible to combine them into a cost-benefit measure that can serve as an objective basis for decision making and deployment configuration ranking. There are several approaches for deriving a suitable cost-benefit measure, with the most appropriate method (or methods) depending on the available information and the intended application. Relevant cost-benefit measures are discussed and compared in the following subsections.

[28] The calculated annualized values are constant across all time periods.

[29] Annualized values are sensitive to the annualization period, *n* (i.e. the duration of the analysis). Specifically, annualized values decrease with increasing annualization periods.

5.3.1 Cost-benefit Measures

Net Present Value

The net present value (NPV) is defined as the arithmetical difference between the present benefits and the present costs (i.e. $PVB - PVC$). It can also be calculated on an annualized basis (i.e. $AVB - AVC$) if alternatives with different time horizons are being considered (this is sometimes referred to as equivalent annual net benefits). A positive NPV indicates that, over time, a project (or a particular ELD deployment configuration) is cost effective, whereas a negative NPV is not. If multiple alternatives have positive NPVs, then the one with the higher value will generate a greater return and would be the preferred choice.

Benefit-cost Ratio

Another cost-benefit measure is the benefit-cost ratio (BCR), which is defined as the ratio of the present benefits over the present costs (i.e. PVB/PVC). It can also be calculated on an annualized basis (i.e. AVB/AVC) if alternatives with different time horizons are being considered. Alternatives with BCRs that are greater than unity can be interpreted to be cost effective, whereas those with BCRs that fail to exceed unity are not. If multiple alternatives have BCR that exceed unity, then the one with the largest value would be the most cost effective and, therefore, the preferred choice.

Cost Effectiveness Ratio

The cost effectiveness ratio (CER) is defined as the ratio of the present value of costs (i.e. *PVC*) to the total benefits, expressed in non-monetary units. Unlike NPV and BCR, which compare values in monetary units, CER compares monetary costs to non-monetary benefits, and is, therefore, not an absolute measure of cost effectiveness and should only be used to compare different alternatives. Essentially, alternatives with smaller CER values are preferred over alternatives with larger CER values. In general, CER should only be relied upon if a significant portion of the total benefits cannot be easily expressed in monetary terms. This is discussed in more detail in the following subsection.

5.3.2 Measures Comparison

Generally, alternatives with positive NPVs or with BCR values that exceed unity can be interpreted to be cost effective. For alternatives with negative NPVs or sub-unity BCR values, implementation may still be warranted on the basis that actions that afford enhanced safety and/or environmental protection are justifiable, provided that implementation costs do not grossly exceed the expected benefits.[30]

If multiple alternatives are shown to be cost effective, NPV is usually the most informative and, therefore, the recommended cost-benefit measure for identifying a preferred alternative because it measures the true contribution of a project to economic welfare (36,37,38). However, a potential limitation with NPV relates to its inability to express the relative magnitude between the benefits and the costs. This is important when alternatives with significantly different budgets are being compared (i.e. when the magnitude of the expenditures between two or more alternatives are significantly different) (38). This is especially problematic, when the resulting NPVs are similar in magnitude and when the uncertainty in the calculated present values is high. To illustrate this limitation, consider a hypothetical scenario in which two options are being evaluated. Option A has a relatively high budget and a total *PVC* of $500,000, whereas Option B has a much lower budget with a total *PVC* of only $50,000. Suppose the calculated *PVB* for Options A and B are $520,000 and $69,000, respectively, the resulting NPV for Options A and B are therefore $20,000 and $19,000, respectively. Based on NPV, the preferred alternative is Option A because it has the highest value of NPV. However, the difference between the NPVs is small (only $1,000) and this may not be enough to confidently select Option A as the preferred choice. Suppose now that the uncertainty on the estimated benefits for both options is ±10%. Taking the uncertainty into account, Option A is found to have a lower bound NPV of negative $32,000, whereas Option B has a lower bound NPV of positive $12,100. This would suggest that Option B, despite having a slightly lower expected NPV, would actually be preferred over Option A because it will always yield a positive NPV, whereas it is possible for Option A to yield a negative NPV. It is not possible to come to this conclusion by evaluating NPV alone. It required an accurate estimate of the uncertainty in the calculated benefits, and accurate uncertainty ranges are often not practical, or possible, to obtain in CBA.[31] Fortunately, BCR values can provide additional information that can help chose the appropriate alternative in such scenarios. The calculated BCRs for Options A and B are 1.04 and 1.38, respectively. The BCR for Option B is comfortably above unity (i.e. 1.38), whereas the BCR for Option A is only slightly above unity (i.e. 1.04). This reveals that there is a more substantial buffer separating the benefits and costs in Option B, and it is, therefore, more likely to remain profitable, or cost effective, despite uncertainty in the benefit calculation.

This example shows that, in the absence of accurate uncertainty ranges, as is often the case with CBA, BCR can be used to evaluate alternatives with similar NPVs when there are significant differences in their overall budgets. BCR does, however, suffer from its own limitations. For instance, because it does not consider the scale of the expenditures involved, a highly profitable,

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[30] This is effectively an application of the principal of As Low as Reasonably Practicable (ALARP) as it pertains to safety risk management (33).

[31] Uncertainty will be addressed in more detail in Section 5.4.

small venture might be preferred over a much larger venture that is less profitable per dollar spent, but that would produce far more absolute profit. Furthermore, BCR is also highly sensitive to the manner in which certain costs, particularly recurrent costs, are accounted for (38), specifically, whether they are subtracted from the benefits or added to the costs (NPV is unaffected by this decision and, therefore, more robust in this respect). Given the limitations associated with BCR, it is generally not recommended to use as the sole cost-benefit measure in a given analysis, but rather it is recommended to use it in addition to NPV in certain scenarios. There may, however, be specific scenarios where it is appropriate to use BCR alone (i.e. for scalable projects in which it can be assumed that the calculated present value costs and benefits scale linearly with the size of the project or, in the case of ELD implementation, the total mileage of deployed ELD). This could be useful in scenarios where the length of deployment is not known or is to be informed by the results of the CBA.

NPV and BCR are useful cost-benefit measures that, when used appropriately, can provide an objective and defensible basis for informed decision making. However, they require all benefits and costs to be expressed in equivalent dollar terms. This might not always be possible and, therefore, it might not always be practical to use them. For example, there might be scenarios where a significant proportion of the expected benefits, are non-monetary. Scenarios with significant non-monetary benefits are best evaluated through the use of CER. It is, however, important to highlight some key limitations associated with the application of CER. Firstly, CER is not an absolute measure of cost efficiency and can, therefore, only be used to compare different alternatives. It cannot be used as an absolute measure of expected cost efficiency as can NPV and BCR. Furthermore, the non-monetized benefits should all be expressed in similar units. CER is not recommended in scenarios where the benefits are comprised of monetary and non-monetary values, or non-monetary values with inconsistent units. CER can, therefore, only be used to compare alternatives on the basis of narrowly defined benefit categories. To this end, it is recommended to limit the application of CER to the following scenarios:

1. In simplified CBAs that are limited in scope, budget or available data for which it is not practical or possible to calculate benefits in monetary terms; and
2. When a significant portion of the overall benefits are non-monetary and are expressed in similar units.

In addition to these scenarios, CER could also be used to evaluate reputation enhancements. In certain scenarios, it might be beneficial to consider reputation enhancements as an additional basis from which to compare multiple alternatives with similar rankings (this is similar to how BCR is sometimes used as a complementary measure to NPV). In such cases, it might be appropriate to use CER as an additional evaluation criterion. However, this first requires some means of quantifying reputation enhancements. One approach is based on the assumption that reputation enhancements are loosely correlated to the calculated total monetary benefits (i.e. *PVB*). This is based on the notion that events that generate adverse effects, such as a significant spill in a high-consequence area, affect the pipeline operator's reputation to a degree that is proportional to the dollar equivalent value associated with that event. More complex relationships could also be explored. For instance, it might be appropriate to assume that only benefits exceeding a given monetary threshold contribute to reputation enhancements. Alternatively, one might wish to consider weighted contributions of different benefit categories (e.g. it might be believed that fatalities damage reputation more than environmental damages in a way that is not proportionate to the respective dollar equivalents).

5.4 Sensitivity Analysis

5.4.1 Overview

The primary purpose of the sensitivity analysis is to gain a better understanding of the effects of uncertain variables on the outcomes that are intended to inform decisions regarding ELD deployment. Sensitivity analysis involves changing selected variables and considering how the change affects the outcome (i.e. the adopted evaluation metric or metrics). The variables that are subject to being changed in a sensitivity analysis could include the input parameters themselves or the underlying assumptions upon which the input parameters are based (e.g. whether CPM is assumed to be deployed on the pipeline, whether the ELD system is subject to a performance ramp-up period, or whether maintenance costs are uniformly distributed in time).

5.4.2 Methodologies

Sensitivity analysis methods, for specific use in CBA for ELD deployment decision making, can be broadly categorized as follows:

<u>Single Variable Testing</u>

Single variable testing involves varying the input parameters, or analysis assumptions, one at a time while holding all other parameters and assumptions constant. Single variable testing is useful for rapidly identifying parameters with the greatest impact on the adopted evaluation metric. The results of this analysis could be used to inform which input parameters might require additional or more detailed information, as well as what assumptions might need to be revisited or assessed more critically.

Single variable testing is simple to implement and doesn't require as much effort as some of the other methods; however, it assumes that the input parameters are not correlated. If some parameters are believed to be correlated, it might be necessary to vary them together, rather than separately. Alternatively, if the degree of intercorrelation among input parameters is not well understood, it might be necessary to consider other methods or to supplement this method with others.

Scenario Analysis

Scenario analysis involves defining a number of alternative situations in which different combinations of input parameters and assumptions are evaluated. The different alternatives should be based on likely situations that may occur, such as: different deployment configurations, or deployment in a high-consequence area versus an area that is not deemed highly sensitive. Scenario analysis may also be used to evaluate best- and worst-case scenarios and to subsequently build an interval representing the extreme range of possible outcomes. The results of a single variable testing analysis could be used to inform which parameter values to use in the best- and worst-case scenarios.

Depending on the number of scenarios being explored and on the complexity of the overarching CBA, scenario analysis does not generally require excessive use of computational resources. Rather, it requires that careful and informed consideration be given to defining the alternative situations.

Monte Carlo Analysis

Single variable testing and scenario analysis aren't typically concerned with estimating the probability of occurrence associated with different outcomes. This requires more advanced and computationally demanding statistical techniques, such as Monte Carlo analysis, whereby statistical sampling and probability distributions are used to simulate the effects of uncertain variables. In a Monte Carlo analysis, the combined effects of many different combinations of input parameters are simultaneously considered, thereby accounting for intercorrelation between, and inherent uncertainty within, the input parameters. Possible outputs of such an analysis could provide operators with additional information beyond what is obtainable using the other more basic sensitivity analysis approaches, such as the mean or expected evaluation criteria value, as well as confidence intervals associated with prescribed confidence levels (i.e. 90% or 95%).

5.4.3 Comparison

With regard to CBA for ELD deployment decision making, a basic sensitivity analysis should include at least some form of scenario analysis. At the very least, the deployment configurations identified in Section 2 should serve as a basis for conducting a scenario analysis (refer to Section 6). Other scenarios, such as the best- and worst-case alternatives, could also be useful if a rough uncertainty interval is required. For more statistically robust and realistic uncertainty evaluations (i.e. confidence intervals), a Monte Carlo analysis should be performed. Finally, single variable testing is recommended if the degree of uncertainty associated with one or more input parameters or assumptions is high. In these cases, single variable testing can be performed on the suspect parameters to verify the extent of their influence on the model output (refer to Section 6).

6. SUMMARY

The developed CBA framework is comprised of four primary elements. A brief summary of the information covered in each of the four major report sections is provided below.

Deployment Configuration Identification

The first step in a CBA for evaluating pipeline ELD technologies consists of identifying, characterizing and ranking viable ELD deployment configurations. In this study, deployment configuration refers to how a particular ELD system is both configured and installed. The highest ranked deployment configurations are carried forward throughout the remainder of the CBA, ensuring that only those with the most potential to generate favorable cost-benefit scores are considered. Identifying and ranking candidate deployment configurations consists of the following key steps:

1. Identify candidate ELD technology vendors: A market survey should be conducted to identify viable technologies for consideration based on their perceived ability to meet performance requirements specific to the pipeline under consideration. Following the market survey, a vendor questionnaire, aimed at gathering pertinent information about the candidate technologies, should be generated and distributed. Finally, a stepwise process should be followed for scoring the technologies based on the responses obtained from the questionnaires to ultimately arrive at a shortlist of vendors for further consideration in the CBA.

2. Establish deployment configuration characteristics: A consistent basis should be established for characterizing the various deployment configurations that will be identified. Deployment configuration characteristics describes the extrinsic parameters of an ELD system in its deployed state and, for the purpose of this framework, is limited to parameters that are known to, or that are likely to, impact the ELD system's performance.

3. Define deployment configurations: Deployment configurations are identified by first considering all the unique combinations of viable deployment configuration characteristics that are possible for each of the candidate ELD technologies. Because different deployment configurations might be associated with different costs, it is important to consider all viable (or practical) deployment configurations in the CBA, even if they may not yield the best possible performance.

4. Rank deployment configurations: The identified deployment configurations are ranked by assigning two relative scores to each of the identified deployment configuration for a given candidate ELD technology: 1) the relative cost score, which is intended to reflect the lifetime cost of deploying and operating a given ELD system in a particular deployment configuration relative to that of all other candidate deployment configurations; and 2) the relative benefit

score, which is intended to reflect the anticipated overall performance of a particular ELD system relative to that of all other candidate deployment configurations.

Cost Estimation

The second step in a CBA involves sourcing and consolidating the information required to accurately estimate the initial costs associated with ELD system procurement and installation, and the recurring costs associated with periodic operation and maintenance for each of the preferred deployment configurations. In estimating initial costs (i.e. procurement and installation costs), it is recommended that the candidate ELD technology vendors be consulted. The accuracy of the initial cost estimates provided by the technology vendors will depend on the accuracy of the information they are provided, specifically, the amount of detail describing the deployment configurations and the performance requirements. Similarly, in estimating recurring costs (i.e. operation and maintenance costs), it is recommended that the ELD technology vendors be consulted to better understand what expenditures are expected with regard to operation and maintenance over the operating life of the ELD system. Some technology vendors might have recurring service fees, such as an annual subscription, which might include additional services such as: an alarm management service, personnel training, maintenance activities and periodic software upgrades. Other technology vendors might simply have a one-time, up-front equipment charge, which doesn’t include any additional services. It is important to know whether or not additional recurring fees are to be expected and, if so, what services they afford.

Benefit Characterization

The third step involves evaluating and quantifying the benefits that can be achieved by ELD implementation for each of the preferred deployment configurations. The following principal benefit categories have been identified:

- Environmental protection enhancements (based on the potential reduction in the quantity released in the event of line failure);
- Safety enhancements (based on the potential reduction in fatalities and injuries due to a reduction in failures); and
- Reputation enhancements (based on the potential increase in public and regulatory confidence resulting from improved levels of safety and/or environmental protection).

There are no obvious or established means to quantitively gauge the reputation enhancements afforded by improved levels of safety or environmental protection. In addition to being difficult to quantitively measure, reputational enhancements are not a significant public concern. On that basis, the guidance provided focuses primarily on environmental protection and life safety benefits.

Environmental protection and life safety benefits are calculated in similar ways and are based on the following key model components:

- Baseline Estimate:
  - The baseline release volume is the expected release volume that would result, given that a release has occurred, assuming no ELD systems are deployed.
  - The baseline fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming no ELD systems are deployed.
- Reduced Estimate:
  - The reduced release volume is the release volume that would be expected to result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
  - The reduced fatality and injury estimate is the expected number of fatalities and injuries that would result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
- Failure Rate Estimate:
  - The failure rate represents the expected rate of occurrence of pipeline releases over a given time period (typically one year) and over a particular length of pipeline.
- Monetization Models:
  - Monetization models are required to convert the calculated reduction in expected release volume into an equivalent dollar measure of the expected environmental impact reduction achieved.
  - Monetization models are required to convert the calculated reduction in expected fatalities and injuries into a dollar equivalent.

Different approaches can be used for combining the listed model components to estimate the environmental protection and life safety benefits. It is suggested that most approaches can be classified as deterministic or probabilistic approaches, or hybrid approaches that combine elements of the deterministic and probabilistic approaches.

Implementation of deterministic approaches tends to be straightforward and only requires relatively simple input data. However, approaches of this nature are generally perceived to be less accurate than comparable probabilistic approaches because they tend to make simplifying assumptions about certain, potentially important, parameters and are not well equipped to account for the uncertainty inherent in the input parameters. Furthermore, they are not well suited to nonlinear monetization models.

Probabilistic approaches use advanced structural reliability models and detailed ILI data to directly predict failure modes, time of failure, release rates and failure probabilities for reported or assumed flaws on the pipeline. Probabilistic approaches are generally more accurate than comparable deterministic approaches; however, they require more specialized data and the analysis tends to be more complex and computationally demanding.

Hybrid approaches combine elements of both the deterministic and probabilistic approaches. The baseline release volume, the reduced release volume and the failure rate are fixed-point constant values. However, unlike deterministic approaches, these values are calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variables. Hybrid approaches differ from probabilistic approaches in that the calculations are not based on reported or assumed flaws and, therefore, structural reliability models and ILI data are generally not required. Rather, they are based on assumed random variables (i.e. hole size distribution, release pressures, etc.) inferred from historical incident data. As a result, hybrid approaches are simpler to implement compared to probabilistic methods, but are not capable of directly predicting time of failure, failure modes and failure probabilities; these values must be calculated or inferred through a separate process later.

Cost-benefit Analysis

The final step in a CBA involves combining the calculated costs and benefits into a meaningful evaluation metric that can be used to objectively compare different ELD deployment alternatives.

The calculated benefits and costs tend to occur at different times throughout the ELD system’s operational life cycle. Therefore, it is critical to discount all benefits and costs into present-day dollars before they can be combined into a meaningful evaluation metric. Selection of an appropriate discount rate, as well as the act of properly distributing benefits and costs throughout time, are therefore critical steps in any CBA.

Different methods are considered for combining the present-day costs and benefits into a cost-benefit measure that can serve as an objective basis for decision making and deployment configuration ranking:

- NPV: Defined as the arithmetical difference between the present benefits and the present costs;
- BCR: Defined as the ratio of the present benefits to the present costs; and

- CER: Defined as the ratio of the present value of costs (i.e. *PVC*) to the total benefits, expressed in non-monetary units.

For most applications, NPV was shown to be the preferred evaluation measure. However, in specific scenarios, BCR and CER can also be used solely or in combination with NPV. For example, BCR might be more appropriate if comparing alternatives that are scalable and for which the total budget is unknown. Similarly, BCR or CER can be used to compare two or more alternatives with similar NPV values. Finally, in scenarios where it is not possible or practical to convert the benefits into dollar equivalents, CER may be used to compare different alternatives in relative terms.

If the input parameters used in the calculation of the costs and/or the benefits are associated with a high degree of uncertainty, it is recommended that these parameters be included in a single variable testing sensitivity analysis. The results of the single variable test can be used to assess the degree to which these suspect parameters are capable of impacting the adopted evaluation metric value or values. Input parameters with a high degree of uncertainty and that have a significant impact on the resulting evaluation metric might warrant additional attention. If possible, it is recommended that additional effort be invested in reducing the uncertainty by collecting additional data or making more informed assumptions. If it is not possible or practical to reduce the degree of uncertainty associated with the suspect input parameters, then it is recommended that the uncertainty be carried forward by calculating upper and lower evaluation metric values for each alternative in the scenario analysis. For more statistically robust and realistic uncertainty intervals (i.e. confidence intervals with prescribed confidence levels), a Monte Carlo analysis could be performed. Monte Carlo analysis requires more detailed information about the input parameter uncertainty and is more computationally taxing than other, more basic methods.

The preferred deployment configurations serve as a basis for conducting a scenario analysis. The scenario analysis is central to objectively evaluating the possible alternatives in terms of their ability to generate positive economic value over the adopted evaluation timescale. The results of the scenario analysis could be used to simply compare different alternatives in relative terms or to provide a quantitative measure of the expected profit associated with different alternatives. The distinction largely depends on the adopted evaluation metric (i.e. NPV or BCR vs. CER) and on the estimated width of the evaluation metric uncertainty intervals associated with the various alternatives. The results of the scenario analysis could also provide a basis for narrowing down the deployment configurations prior to performing a subsequent, more comprehensive iteration of the CBA.

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APPENDIX A - FRAMEWORK DEMONSTRATION

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A.1. INTRODUCTION

A.1.1 Objective

This appendix documents a demonstration exercise in which a hypothetical cost-benefit analysis (CBA) was performed to evaluate and compare three external leak detection (ELD) systems for possible implementation on a hypothetical new-construction pipeline (i.e. the "demonstration pipeline"). The objective of the exercise is to demonstrate and illustrate the application of the External Leak Detection Cost-benefit Analysis Framework developed in this project (i.e. the main body of this report, hereafter referred to as the "CBA Framework").

A.1.2 Framework Demonstration Outline

The demonstration exercise described in this document steps through the various sections of the CBA Framework and makes reference to the guidance and methodologies outlined in the CBA Framework. The following is a list of the main sections of the demonstration document, which mirror the main sections from the CBA Framework:

- Deployment Configuration Identification: This section demonstrates application of the process outlined in the CBA Framework for identifying and characterizing viable ELD deployment configurations for consideration in the CBA.
- Cost Estimation: This section demonstrates application of the process outlined in the CBA Framework for estimating the lifetime costs associated with ELD deployment and operation.
- Benefit Characterization: This section demonstrates the process outlined in the CBA Framework for quantifying the benefits that can be achieved with ELD.
- Cost-benefit Analysis: This section demonstrates the process outlined in the CBA Framework for combining the calculated costs and benefits into an evaluation metric which can be used to objectively compare different ELD deployment alternatives for the purpose of decision making.

To facilitate understanding of the linkage between this process demonstration document and the associated CBA Framework, frequent quotations are included herein from relevant sections of the CBA Framework.

A.1.3 Demonstration Pipeline Selection Considerations

The selection of the demonstration pipeline was guided by two primary considerations: to provide a clear and practical demonstration of selected key aspects of the CBA Framework; and to make the findings of the demonstration exercise as broadly applicable as possible. To this end, the demonstration pipeline's key attributes were informed through discussions and consultation with the project Technical Advisory Panel (TAP), as well as through relevant public domain literature.

Key attributes of the demonstration pipeline, as they relate to the demonstration exercise, are summarized as follows:

- The demonstration pipeline is assumed to be a new-construction pipeline. Accordingly, the ELD systems are assumed to be installed simultaneously with the construction of the pipeline. Further, the ELD systems are assumed to be deployed in an existing open trench.
- Crude oil and natural gas represent the substances most commonly transported by pipelines in the United States[1] and, for demonstration purposes, consideration was therefore given to analyzing either a crude oil or natural gas pipeline. Life safety benefits associated with natural gas pipeline releases are believed to be achieved predominantly through break prevention (i.e. via encroachment detection), rather than reduced detection time.[2] However, not all ELD systems are equipped with encroachment detection functionality and, therefore, might not be effective at generating significant life safety benefits for natural gas pipelines. Further, the environmental benefits to be achieved from reducing the expected release volume of natural gas is assumed to be small compared to that of crude oil. Crude oil is therefore believed to be better suited to demonstrating the capabilities of most commercially available ELD systems and, on that basis, a crude oil pipeline was chosen for demonstration purposes.
- The majority (72%) of reported incidents on onshore, crude oil pipelines occurred on subsurface pipelines or pipeline segments (2). On this basis, the demonstration pipeline is assumed to be a buried pipeline.
- A computational pipeline monitoring (CPM) system is assumed to be installed and operational on the demonstration pipeline. It is further assumed that the candidate ELD systems will operate in parallel with, but independently of, the CPM system and, therefore, will not influence the CPM system's performance and vice versa. The performance characteristics of the deployed CPM system are assumed to be consistent with typical systems installed on similar pipelines (refer to Section A.4.2.2 for additional details on the assumed performance of the demonstration pipeline's CPM system).
- A nominal operational life cycle of 50 years was assumed for the demonstration pipeline. It was further assumed that the candidate ELD systems have an equivalent operational life and that they will begin operating in the same year as the pipeline begins operation (i.e. Year 1).

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[1] In 2019, crude oil pipelines were found to have the highest total mileage (36% of total mileage) among hazardous liquid pipelines in the United States (1). Similarly, natural gas pipelines were found to have the highest total mileage (99% of total mileage) among gas pipelines in the United States (1).

[2] Life safety consequences associated with natural gas releases are based predominantly on thermal radiation caused by jet fires. Further, natural gas is less dense than air and is odorized; therefore, the possibility of delayed or remote ignition is small compared to the possibility of immediate ignition. Therefore, an ELD system's ability to enhance the detection time of an existing jet fire is not expected to contribute significantly to life safety benefits compared to an ELD system's ability to potentially prevent the jet fire via encroachment detection.

- The ELD system is assumed to be deployed along a 155-mile section of the demonstration pipeline. This length is sufficiently long to require multiple ELD interrogator units (assuming a nominal interrogator range of 30 to 60 miles), thereby ensuring that the resulting performance of the candidate ELD technologies reflects typical long range ELD deployments. This length is also believed to take advantage of the volume pricing offered by many commercially available ELD technologies, thereby ensuring that the assumed ELD costs are representative. It is further assumed that the 155-mile section traverses relatively low population areas.
- A nominal operator response time of 2 hours was assumed in the benefit modeling section. Operator response time is defined and discussed in more detail in Section A.4.2.3.
- Crude oil pipeline releases (excluding breaks[3]) reported on PHMSA-regulated pipelines between 2010 and 2019 occurred at an average pressure of 305 psi, with a majority of the releases occurring at pressures between 100 and 500 psi (2). On that basis, leak simulations over operating pressures ranging from 100 to 500 psi were considered reasonable and appropriate for the demonstration pipeline.
- An evaluation of soil types encountered by existing liquid hydrocarbon pipelines in the continental United States, shown graphically in Figure A.1.1[4], found that significant mileage traverses sandy soils mixed with relatively small proportions of silt and/or clay. On this basis, a sandy soil with minimal amounts of silt and clay was assumed to apply to the demonstration pipeline at locations where ELD system deployment is contemplated. This information was provided to the ELD technology vendor consultants to assist with their predictions of the performance and deployment costs associated with their respective technologies.

[3] It was assumed that the candidate ELD systems are not likely capable of offering significant improvements over existing CPM systems with regard to break detection. It was therefore decided that the most practical way of accounting for CPM performance would be to assume that breaks are readily detectable by the demonstration pipeline's CPM system, while other, smaller magnitude release events are not. Refer to Section A.4.2.2 for more detail on this topic.

[4] The map was developed from Pennsylvania State University's soil information for environmental modeling and ecosystem management website (3).

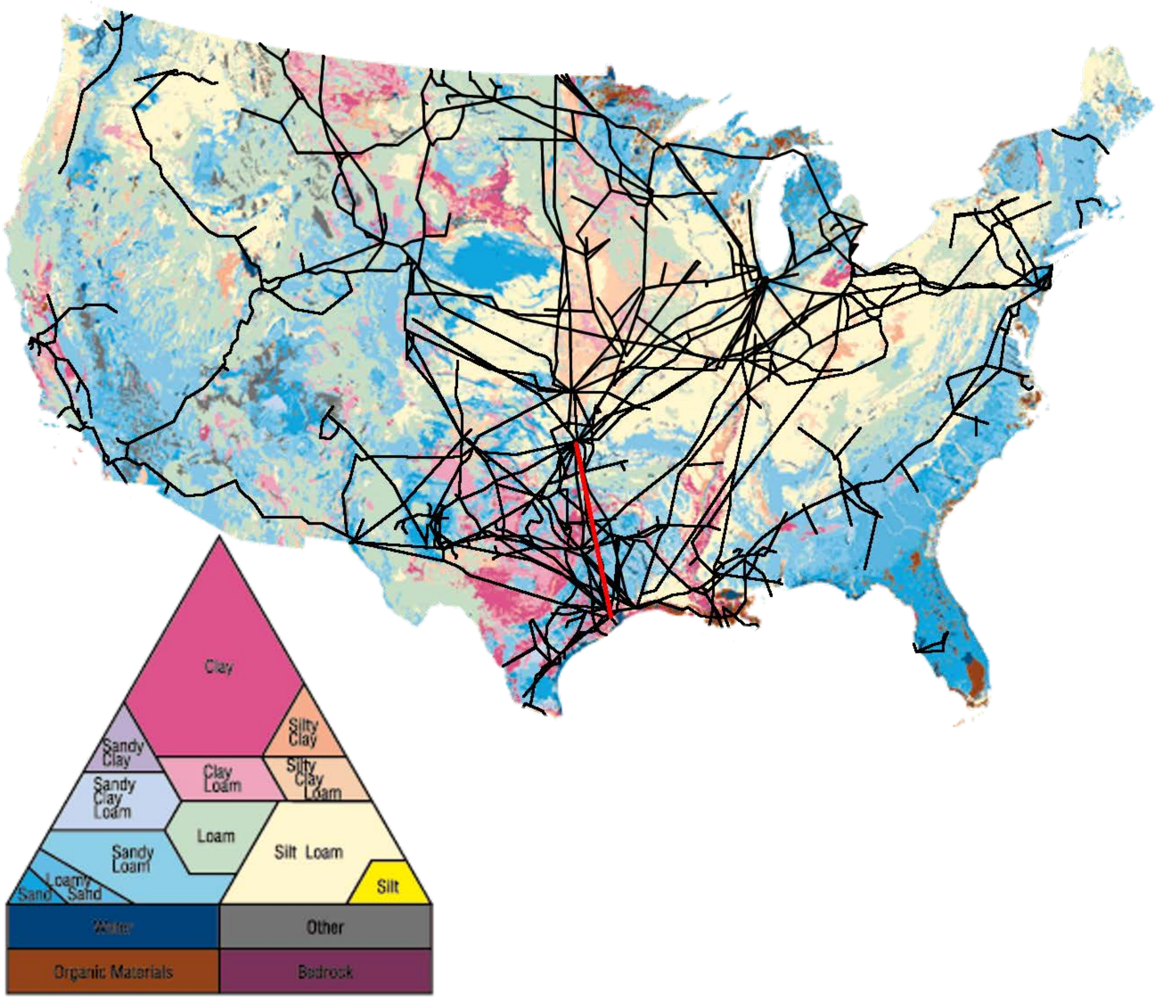

Figure A.1.1 Soil Textures for the Continental United Sates and Routing of Major Existing Hydrocarbon Liquid Pipelines

A.2. DEPLOYMENT CONFIGURATION IDENTIFICATION

A.2.1 Overview

The objective of this section is to identify and characterize viable ELD deployment configurations for consideration in the CBA. The CBA Framework defines deployment configurations as follows (refer to Section 2.1 in the CBA Framework):

> *ELD systems can be deployed in many different locations and orientations relative to the pipeline. They can also be deployed along with auxiliary components, such as conduit, straps or supports. The performance of, as well as the installation cost associated with, a given ELD system is significantly impacted by the way it is deployed in the field. It is therefore important to identify and characterize the possible deployment configurations for each ELD technology being considered in the CBA. In this study, deployment configuration refers to how a particular ELD system is both configured and installed. It describes the extrinsic parameters of an ELD system in its deployed state and, for the purpose of this framework, is limited to parameters that are known to, or that are likely to, impact the ELD system's performance.*

This step in the demonstration exercise consists of first identifying candidate ELD technologies and viable deployment configurations, then prioritizing the identified deployment configurations such that only those with the most potential to generate favorable cost-benefit scores are carried forward (i.e. the preferred deployment configurations).

In the following subsections, the process and methodology used in identifying and ranking the deployment configurations is reviewed and a brief summary of the identified preferred deployment configurations is provided.

A.2.2 Process and Methodology

A.2.2.1 Overview

Consistent with the guidance provided in the CBA Framework, identifying and ranking candidate deployment configurations consists of the following key steps:

1. Identify candidate ELD technology vendors

2. Establish deployment configuration characteristics

3. Define deployment configurations

4. Rank deployment configurations

Each of the listed steps are discussed in detail in the following subsections:

A.2.2.2 Identify Candidate ELD Technology Vendors

The CBA Framework provides the following guidance with regard to identifying candidate ELD technology vendors (refer to Section 2.2 in the CBA Framework):

> *To obtain an initial list of vendors for consideration (i.e. candidate ELD technologies), a market survey should first be conducted. The purpose of the market survey is to identify viable technologies for consideration based on their perceived ability to meet performance requirements specific to the pipeline under consideration. Following the market survey, a vendor questionnaire, aimed at gathering pertinent information about the candidate technologies, should be generated and distributed. The purpose of the vendor questionnaire is to facilitate the collection of targeted information regarding the candidate vendors, their services and the performance of their systems as they relate to the specific performance requirements. Finally, a stepwise process should be followed for scoring the technologies, based on the responses obtained from the questionnaires, to ultimately arrive at a shortlist of vendors for further consideration in the CBA.*

A comprehensive market survey, as described in the CBA Framework, for real ELD technologies can be expensive and time consuming. The concepts and guidance provided in the CBA Framework can be demonstrated effectively with hypothetical ELD technologies, provided their performance and costs are reasonably representative of commercially available ELD technologies. On that basis, and because a detailed demonstration of an ELD market survey with real ELD technologies is already outlined in a 2018 report prepared for PHMSA (4), it was decided to simply select hypothetical ELD technologies that are reasonably representative (in terms of cost and performance) of commercially available ELD technologies. This allowed for efforts to be focused on demonstrating the other elements of the CBA Framework. Accordingly, three candidate, hypothetical ELD technologies were defined for evaluation in the demonstration exercise:

- Distributed acoustic sensing (DAS): DAS systems are able to measure and interpret vibrations caused by fluid escaping from the release point (i.e. leak noise).
- Vapor sensing tubes (VST): VST systems are able to infer releases by measuring the concentration of hydrocarbon vapors in the soil along a pipeline. Conventional technologies are sensitive to vapors from light-end liquid hydrocarbons and heavier crude oil.
- Distributed temperature sensing (DTS): DTS systems are able to infer releases by measuring local temperature changes resulting from either direct contact with released product or conductive heating of the soil surrounding the sensor.

These technologies are considered representative of commercial ELD systems that have been installed on existing long-distance pipelines. The performance and costs of these systems were determined through a combination of TAP member guidance, discussions with representative ELD technology vendors and available public domain literature. Specific details regarding the costs and anticipated performance of the candidate ELD technologies are provided in subsequent sections.

It is noted that other technology types exist (hydrocarbon sensing cables, point sensor arrays, hybrid systems, etc.). However, the selected technologies are well established, and many pipeline operating companies are reasonably familiar with them. Further, they are believed to adequately capture the range of performance capabilities of existing commercial systems in terms of leak detection sensitivity and response time.

A.2.2.3 Establish Deployment Configuration Characteristics

In identifying and prioritizing viable deployment configurations, the CBA Framework recommends first establishing a consistent basis by which to characterize the various deployment configurations. To assist with this process, the CBA Framework proposes the following set of basic characteristics[5]:

- Sensor Position: the sensor's location relative to the pipeline, as well as other relevant references objects or reference geometries.
- Sensor Orientation: the angular position of an ELD sensor relative to the reference frame that is assigned to it.
- Placement Pattern: the shape, as well as the spacing and the total number, of sensors in the array in cases where multiple sensors are deployed together.
- Placement Environment: relevant physical characteristics of the environment surrounding a particular ELD sensor or group of sensors.
- Use of Auxiliary Structures: whether or not the ELD sensor is to be installed with a passive structure, such as conduit.

The candidate ELD technologies are all distributed, cable-based technologies with assumed omnidirectional (i.e. axisymmetric) sensitivity profiles. As such, sensor orientation and placement patterns are not relevant and will not be considered in the characterization of deployment configurations. The remaining deployment configuration characteristics (i.e. sensor position, placement environment and use of auxiliary structures) will, therefore, form the basis for the deployment configuration identification demonstration.

The sensor position characteristics consists of two continuous variables: one describing the radial distance from the sensor to the pipeline surface with values ranging from zero (i.e. on the pipe surface) to the boundary of the pipeline right-of-way (ROW); and the other describing the

[5] Cursory descriptions are provided here for convenience. For more detailed descriptions of the deployment configuration characteristics, refer to the CBA Framework.

circumferential, or clock, position of the sensor relative to the top dead center (TDC) of the pipeline.

Placement environment is comprised of several individual continuous variables describing relevant soil properties. The soil properties assumed to most strongly influence the performance and placement of the candidate ELD systems are porosity, permeability, thermal conductivity and density.

Finally, all sensor positions were considered for placement both inside and outside of a conduit structure. No other auxiliary structures were considered.

A.2.2.4 Define Deployment Configurations

Based on the identified deployment configuration characteristics, the CBA Framework provides the following guidance with regard to defining deployment configurations for each of the candidate ELD systems (refer to Section 2.4 in the CBA Framework):

> *Deployment configurations are identified by first considering all the unique combinations of viable deployment configuration characteristics that are possible for each of the candidate ELD technologies. Guidance from the candidate ELD technology vendors can then help identify which combinations are applicable to each ELD technology being considered.*

Because the sensor position and placement environment characteristics involve continuous variables, the number of unique combinations of deployment configuration parameters is infinite. To address this, the CBA Framework recommends categorizing continuous deployment configuration parameters such that the subsequent categories result in distinct degrees of perceived deployability and interference, where deployability and interference are defined as follows:

- Deployability is defined as the ease of installation associated with a particular deployment configuration.
- Interference is defined as the predicted level of impact that an ELD system (or sensor) associated with a particular deployment configuration would have on the pipeline's operation.

The CBA Framework further recommends the following (refer to Section 2.4 in the CBA Framework):

> *In cases where considering deployability and interference only leads to discrete ranges of a particular deployment configuration parameter rather than discrete categorical values, it is recommended that the value within each range that is believed to yield the best relative performance only be considered. Here, relative performance is defined as*

an approximate aggregate measure of overall performance (i.e. sensitivity, robustness, accuracy and reliability) for a given ELD technology.

Consistent with the guidance provided in the CBA Framework, the following key elements were considered in evaluating the degree of deployability, interference and relative performance for the purpose of categorizing the deployment configuration characteristics comprising of continuous variables:

Soil Properties

The demonstration pipeline is a new-construction pipeline; accordingly, it is assumed that a trench has already been excavated; therefore, soil properties are only assumed to affect the relative performance and not the deployability or interference. On that basis, only soil properties believed to affect relative performance are considered in the categorization exercise. The identified relevant soil properties are assumed to differ significantly in the following locations:

- Backfill: defined as the region that is within the trench boundary, but above the pipe bottom plane (i.e. the horizontal plane that is tangent to the pipe bottom). Soil used for backfill is assumed to have relatively high porosity and permeability, and relatively low thermal conductivity and placement density.
- Bedding: defined as the region that is within the trench boundaries, but below the pipe bottom plane. Soil used for bedding are assumed to have medium-to-low porosity and permeability, and medium thermal conductivity and placement density.
- Native Soil: defined as the region that is outside the trench boundaries, but below the soil surface. Native soils are assumed to have medium porosity, low permeability, and relatively high thermal conductivity and density.
- Soil Surface: defined as the region that is adjacent to the free surface of the soil (i.e. top of ground). Soil properties here are taken to be similar to those of the backfill soil; however, sensors located here are assumed not to be surrounded by as much soil and, therefore, are potentially subjected to higher degrees of environmental, thermal and acoustic noise.

Equipment Usage Costs

The demonstration pipeline is assumed to be a new-construction pipeline with an existing open trench. Accordingly, excavation equipment (beyond what is already required for installing the pipeline) is only required for sensors that are deployed outside the trench boundaries. Equipment usage costs are therefore assumed to be minimal for deployment positions that are located within the trench boundaries and more significant for deployment locations that are outside the trench boundaries (excluding those that are on the soil surface).

Operational Activities

The potential for operational activities being adversely affected by the presence of ELD sensors is assumed to depend on the proximity of potential ELD sensors to the pipe surface. ELD sensors deployed on the pipe surface are assumed to interfere more with operational activities compared to those deployed off the pipe surface, and sensors deployed outside the trench boundaries are assumed to have minimal interference potential.

Construction Practices

Construction practices assumed to influence the deployability and interference potential of candidate deployment configurations consist primarily of safety restrictions preventing or limiting the work that can be safely conducted within the trench, and the adopted construction sequencing scheme, which refers to the order in which major elements (pipe, bedding, backfill, ELD sensors, etc.) must be installed. With regard to safety restrictions, it is assumed that workers are not permitted within the boundaries of the trench once the pipe has been lowered into the trench. This means that ELD sensors that cannot simply be lowered into the trench from above may require additional tools, equipment, and/or procedures to ensure they are deployed correctly. Specifically, sensors deployed on the pipe surface are assumed to require the greatest amount of additional tools and procedures and, therefore, are assumed to have low deployability relative to other deployment configurations that involve placement in the backfill region. Similarly, sensors deployed in the so-called shadow region (i.e. the area defined as being within the shadow that would be cast on the trench floor if a light were shone on the pipe from directly above) are assumed to have low-to-medium deployability because they cannot simply be lowered into the trench from above, but are assumed to require less additional effort and equipment compared to sensors deployed on the pipe surface.

With regard to the construction sequencing scheme, it is assumed that the pipeline is constructed in discrete sections; while these sections will eventually all be connected, they are not necessarily built in order of adjacency. On that basis, it is assumed that ELD sensors that can be blown or pulled through conduit are less disruptive and, therefore, associated with higher deployability compared to those that cannot be deployed in conduit (despite having slightly higher material costs due to the conduit itself). Further, it is assumed that sensors deployed in the bedding or at intermediate heights within the backfill are assumed to be more disruptive and, therefore, have lower deployability compared to sensors that are not deployed in the bedding or that are intended to reside on top of the bedding layer.

Based on the above considerations and on the anticipated relative ELD performance as a function of the previously discussed deployment configuration characteristics (refer to Section A.2.2.3), a total of 14 deployment configurations for each of the three candidate ELD technologies were identified. These configurations are listed and described in Table A.2.1, and shown schematically in Figure A.2.1.

Deployment Configuration Number	Sensor Position	Placement Environment	Auxiliary Structures
1	On soil surface, 12 o'clock	Surface	Bare cable
2	On soil surface, 12 o'clock	Surface	In conduit
3	In trench, above bedding, 12 o'clock	Unconsolidated backfill	Bare cable
4	In trench, above bedding, 12 o'clock	Unconsolidated backfill	In conduit
5	In native soil, 10 or 2 o'clock	Native soil	Bare cable
6	In native soil, 10 or 2 o'clock	Native soil	In conduit
7	On pipe surface, 12 o'clock	Unconsolidated backfill	Bare cable
8	On pipe surface, 12 o'clock	Unconsolidated backfill	In conduit
9	On bedding layer, 8 or 4 o'clock	Unconsolidated backfill	Bare cable
10	On bedding layer, 8 or 4 o'clock	Unconsolidated backfill	In conduit
11	On bedding layer, 5 or 7 o'clock (shadow)	Unconsolidated backfill	Bare cable
12	On bedding layer, 5 or 7 o'clock (shadow)	Unconsolidated backfill	In conduit
13	Bottom of bedding, 6 o'clock	Bedding	Bare cable
14	Bottom of bedding, 6 o'clock	Bedding	In conduit

Table A.2.1 Characteristics of Candidate Deployment Configurations

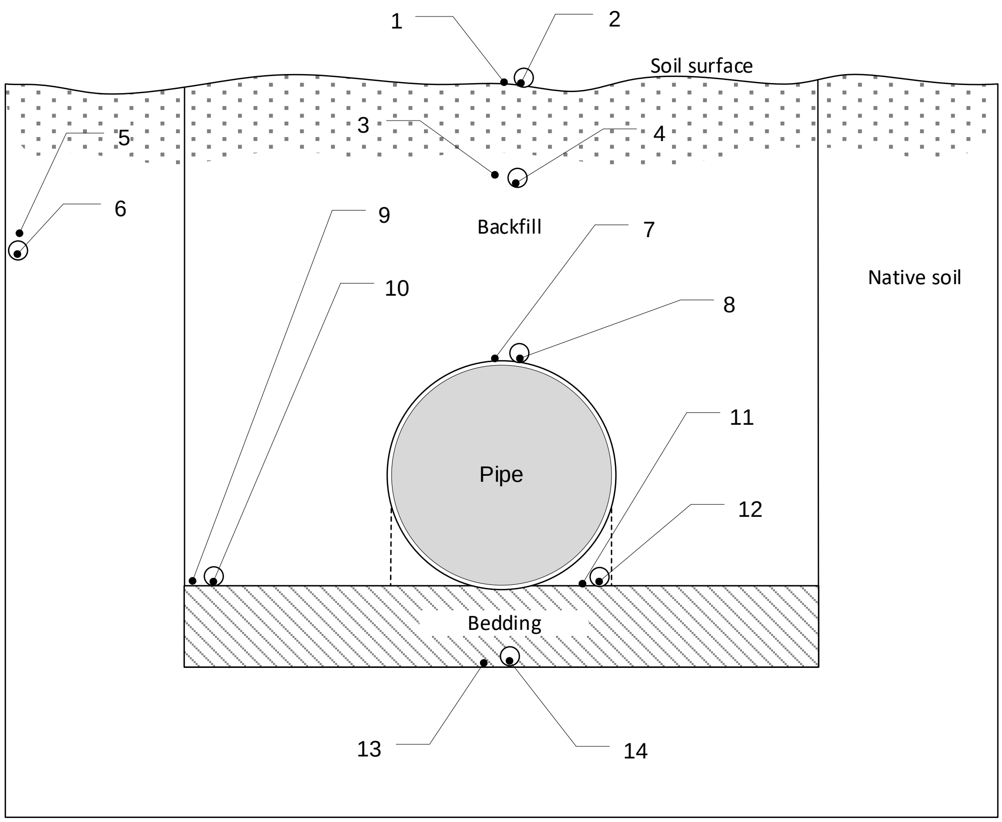

Figure A.2.1 Candidate Deployment Configuration Schematic

A.2.2.5 Rank Deployment Configurations

Once viable deployment configurations have been established, and candidate ELD technology vendors have been identified, it is necessary to characterize and rank the identified deployment configurations, with the objective being to only carry forward the highest ranking, and therefore most promising, deployment configurations. To this end, the CBA Framework recommends assigning two scores to each of the identified deployment configuration for a given candidate ELD technology. The two scores are defined in the CBA Framework as follows (refer to Section 2.5 of the CBA Framework):

- Relative Cost Score:

  The relative cost score is intended to reflect the lifetime cost of deploying and operating a given ELD system in a particular deployment configuration relative to that of all other candidate deployment configurations. It is obtained by considering the joint degree of deployability and interference associated with each of the candidate deployment configurations.

- Relative Benefit Score:

  The relative benefit score is intended to reflect the anticipated overall performance of a particular ELD system relative to that of all other candidate deployment configurations. The relative benefit score should be based on the relative performance defined previously (i.e. it represents an aggregate approximate measure of overall ELD performance for a given deployment configuration). Determining the benefit score will likely require consultation with the candidate ELD technology vendors and, possibly, independent testing and/or modeling.

Consistent with the guidance provided in the CBA Framework, each of the candidate deployment configurations was assigned a relative cost and benefit score. The relative cost and benefit scores were based on simple scoring scales consisting of sequentially ranked integers ranging from 1 to 10, with 1 representing the deployment configuration (or configurations) associated with the highest costs or lowest relative benefits and 10 representing the deployment configuration (or configurations) with the lowest costs or highest relative benefits.

Once relative rankings are developed for each of the identified deployment configurations, the CBA Framework recommends the following (refer to Section 2.5 of the CBA Framework):

> *…[T]he next step is to combine the scores (through multiplication) to obtain an overall deployment ranking score. Only the deployment configurations with the highest overall scores (i.e. "the preferred deployment configurations") will be considered in the full CBA. The final number of deployment configurations to carry forward will largely depend on the level of effort the operator is willing to devote to the CBA. It will also depend on the individual overall scores assigned to each deployment configuration.*

Consistent with the guidance provided in the CBA Framework, the relative cost and benefit scores were multiplied to obtain an overall score. The relative cost and benefit scores, as well as the overall scores, for each of the candidate deployment configurations are summarized in Table A.2.2 and the deployment configurations with three highest overall scores for each of the candidate ELD technologies are highlighted in green.

Deployment Configuration Number	DAS			VST			DTS		
	Cost Score	Benefit Score	Overall Score	Cost Score	Benefit Score	Overall Score	Cost Score	Benefit Score	Overall Score
1	7	1	7	7	1	7	10	1	10
2	10	1	10	10	1	10	7	1	7
3	3	6	18	3	8	24	6	8	48
4	6	6	36	6	8	48	3	8	24
5	1	2	2	1	2	2	4	2	8
6	4	2	8	4	2	8	1	2	2
7	4	10	40	4	8	32	7	8	56
8	7	10	70	7	8	56	4	8	32
9	6	6	36	6	8	48	9	8	72
10	9	6	54	9	8	72	6	8	48
11	5	8	40	5	10	50	8	10	80
12	8	8	64	8	10	80	5	10	50
13	2	6	12	2	6	12	5	6	30
14	5	6	30	5	6	30	2	6	12

Table A.2.2 Relative Cost and Benefit Scores and Overall Scores for the Candidate Deployment Configurations

A.2.3 Results and Conclusions

Consistent with the guidance provided in the CBA Framework, the three deployment configurations with the highest overall scores for each of the candidate ELD technology vendors were carried forward. These nine deployment configurations (i.e. three for each of the candidate ELD technologies) are renamed according to their relative position in the trench for convenience and are hence forth referred to as the preferred deployment configurations. The preferred deployment configurations are listed and described in Table A.2.3, and shown schematically in Figure A.2.2.

Deployment Configuration	Sensor Position	Placement Environment	Auxiliary Structures
DAS - On Pipe	On pipe surface, 12 o'clock	Unconsolidated backfill	In conduit
VST - On Pipe	On pipe surface, 12 o'clock	Unconsolidated backfill	Bare cable
DTS - On Pipe	On pipe surface, 12 o'clock	Unconsolidated backfill	In conduit
DAS - Near Field	On bedding layer, 5 or 7 o'clock (shadow)	Unconsolidated backfill	In conduit
VST - Near Field	On bedding layer, 5 or 7 o'clock (shadow)	Unconsolidated backfill	Bare cable
DTS - Near Field	On bedding layer, 5 or 7 o'clock (shadow)	Unconsolidated backfill	In conduit
DAS - Far Field	On bedding layer, 8 or 4 o'clock	Unconsolidated backfill	In conduit
VST - Far Field	On bedding layer, 8 or 4 o'clock	Unconsolidated backfill	Bare cable
DTS - Far Field	On bedding layer, 8 or 4 o'clock	Unconsolidated backfill	In conduit

Table A.2.3 Characteristics of Preferred Deployment Configurations

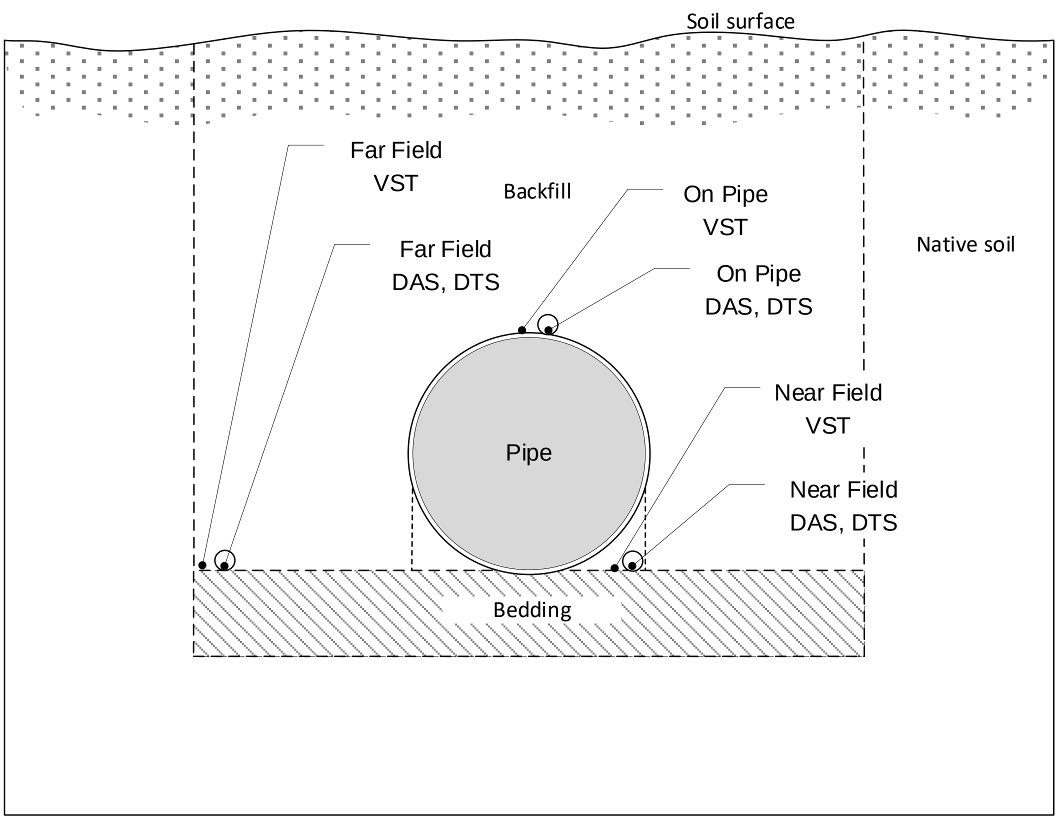

Figure A.2.2 Preferred Deployment Configurations Schematic

A.3. COST ESTIMATION

A.3.1 Overview

The objective of this section is to estimate the lifetime costs associated with ELD deployment and operation. The CBA Framework provides guidance for sourcing and consolidating the information required to accurately estimate the initial costs associated with ELD system procurement and installation, and the recurring costs associated with periodic maintenance expenditures required to ensure system functionality over the operating lifecycle of the pipeline.

In the following subsections, the process and methodology used in estimating ELD costs are reviewed and a summary of the costs associated with each of the preferred deployment configurations is provided.

A.3.2 Process and Methodology

A.3.2.1 Overview

Consistent with the guidance provided in the CBA Framework, costs were arranged into two main categories: initial costs and recurring costs. The following subsections demonstrate the process followed for obtaining initial and recurring cost estimates for each of the preferred deployment configurations identified in Section A.2.

A.3.2.2 Initial Costs

The CBA Framework defines initial costs as follows (refer to Section 3.2 in the CBA Framework):

> *Initial costs are comprised of procurement costs and installation costs. They are usually incurred concurrently with the pipeline construction, but might occur at different times throughout the pipeline's operational life cycle (e.g. retrofit or staged ELD deployments).*

Procurement and installation costs for the candidate ELD technologies for each of the preferred deployment configurations were determined through a combination of TAP member guidance, discussions with representative ELD technology vendors and available public domain literature.

Procurement costs are associated with the ELD equipment itself, whereas installation costs are associated with the construction and commissioning of the ELD systems. Procurement costs are broken down into sensor costs and equipment costs. Sensor costs include the sensor cable (i.e. proprietary tube for VST, and generic telecom optical fiber cable for DAS and DTS), as well as the required connectors and auxiliary structures (i.e. conduit). The equipment costs include the interrogator units, the required power provisions and the communication equipment required to interface with the demonstration pipeline's supervisory control and data acquisition (SCADA) system. Installation costs are broken down into construction costs and commissioning costs. Construction costs include labor, equipment rental material and consumables; commissioning costs include ELD commissioning and calibration, as well as costs associated with training and technology integration.

A.3.2.3 Recurring Costs

The CBA Framework defines recurring costs as follows (refer to Section 3.3 in the CBA Framework):

> *Recurring costs are those that are incurred periodically over the course of the ELD system's operational life. They are comprised of operation and maintenance costs, costs associated with responding to false alarms and cost of interference to pipeline operation.*

Guidance from ELD technology vendors suggests that false alarms for ELD systems in the preferred deployment configurations, as described in Section A.2, are exceedingly rare and, therefore, costs associated with responding to false alarms are assumed to be insignificant and were not considered in the demonstration exercise.[6] Similarly, the costs of interference with pipeline operation are assumed to be low compared to the maintenance costs and, therefore, were also not considered in the demonstration exercise. Accordingly, operation and maintenance costs were assumed to represent the majority of the recurring costs and were, therefore, the basis for estimating the recurring costs for each of the preferred deployment configurations.

Operation and maintenance costs for the candidate ELD technologies for each of the preferred deployment configurations were determined through a combination of TAP member guidance, discussions with representative ELD technology vendors and available public domain literature.

A.3.3 Results and Conclusions

The initial and recurring costs, broken down as described in the previous subsection, are summarized for each of the preferred deployment configurations in Table A.3.1.

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[6] ELD systems (either the candidate technologies or others) deployed in different deployment configurations and/or on a pipeline with different attributes might have a non-zero false alarm rate.

Deployment Configuration	Initial Costs			Recurring Costs
	Procurement (USD/mile)	Installation (USD/mile)	Total Initial Costs (USD/mile)	Operation and Maintenance (USD/mile-year)
DAS - On Pipe	40,234	96,561	136,794	2,414
VST - On Pipe	20,117	120,701	140,818	32
DTS - On Pipe	43,452	96,561	140,013	1,609
DAS - Near Field	40,234	64,374	104,607	2,414
VST - Near Field	20,117	80,467	100,584	32
DTS - Near Field	43,452	64,374	107,826	1,609
DAS - Far Field	40,234	32,187	72,421	2,414
VST - Far Field	20,117	40,234	60,350	32
DTS - Far Field	43,452	32,187	75,639	1,609

Table A.3.1 Estimated ELD Costs for Preferred Deployment Configurations

Guidance provided by the TAP and ELD vendors revealed that a relatively wide range of deployment costs are possible. The cost range provided by the TAP and ELD vendors are largely based on pilot project installations and, therefore, do not necessarily reflect the true costs of deploying similar ELD systems on larger scales. Pilot installations are assumed to be less cost effective than actual deployments because the construction practices and deployment processes are assumed not to be fully optimized. Installation costs associated with ELD deployment are expected to lessen with time as better practices are developed and as the existing processes are improved. The costs listed in Table A.3.1 are meant to represent actual deployments rather than pilot installations and, on that basis, are on the lower range of the costs range provided by the TAP and ELD vendors.

A.4. BENEFIT CHARACTERIZATION

A.4.1 Overview

The objective of this section is to quantify the benefits that can be achieved with ELD implementation for each of the preferred deployment configurations that were identified in Section A.2.

The CBA Framework suggests that ELD implementation has the potential to provide benefits in two ways:

1. By reducing the duration of pipeline releases, thereby reducing the amount of product that is lost to the environment in the event of a leak or break; and

2. By preventing pipeline leaks or breaks, thereby reducing the potential for product loss and associated fatalities or injuries.

Based on the above, the CBA Framework identifies the following principal benefit categories:

- Environmental protection enhancements (based on the potential reduction in the quantity released in the event of line failure);

- Safety enhancements (based on the potential reduction in fatalities and injuries due to a reduction in failures); and

- Reputation enhancements (based on the potential increase in public and regulatory confidence resulting from improved levels of safety and/or environmental protection).

The applicable benefit categories are case-specific and depend on the attributes of the demonstration pipeline. Because the demonstration pipeline is assumed to transport crude oil, it is assumed to have a relatively low ignition likelihood compared to that of a natural gas pipeline. Furthermore, the pipeline section, along which ELD deployment being considered, is assumed to traverse low population areas. Lastly, the candidate ELD systems are assumed not to have encroachment detection capabilities. Therefore, potential for break prevention is assumed to be minimal. Given the relatively low life safety risks associated with the transport of crude oil in the demonstration pipeline, especially compared to natural gas, life safety benefits are assumed not to be significant and are, therefore, not considered in the benefit characterization exercise. As outlined in the CBA Framework document, there is no obvious or established means to quantitively gauge the reputation enhancements afforded by improved levels of safety or environmental protection, and since reputational enhancements are not a significant public concern they were not considered in the demonstration CBA.

Based on the above, the overall benefit was assumed to involve environmental protection enhancements. More specifically, it was assumed that the overall benefit is based wholly on the environmental impact reduction afforded by the reduction in release volume that would be the expected result of ELD implementation.

In the following subsections, the process and methodology used in calculating the environmental enhancement benefit associated with the preferred deployment configurations are reviewed, and a brief summary of the results is provided.

A.4.2 Process and Methodology

A.4.2.1 Overview

The CBA Framework identifies the following required components for estimating environmental benefits based on release volume reduction:

- Baseline Release Volume Estimate: the expected release volume that would result, given that a release has occurred, assuming no ELD systems are deployed.
- Reduced Release Volume Estimate: the release volume that would be expected to result, given that a release has occurred, assuming a particular ELD system is deployed at the location of interest.
- Failure Rate Estimate: the expected rate of occurrence of pipeline releases over a given time period (typically one year) and over a particular length of pipeline.
- Monetization Models: required to convert the calculated reduction in expected release volume into an equivalent dollar measure of the expected environmental impact reduction achieved.

The CBA Framework discusses each of these model components in detail and provides general methods for applying them in a benefit calculation. The guidance provided in the CBA Framework focuses on the following general modeling methods:

- Deterministic approaches
- Probabilistic approaches
- Hybrid approaches

The demonstration pipeline is a new build pipeline and therefore it is assumed that there is no inline inspection (ILI) data from which to leverage a full probabilistic analysis (refer to Section 4 in the CBA Framework for details pertaining to the use of ILI data in a probabilistic benefit characterization approach). Based on the information available and on the stated assumptions, it was determined that a hybrid approach would provide the most practical means of calculating the required estimates, while also accounting for the inherent uncertainty in some of the input data.

The CBA Framework defines hybrid approaches as follows (refer to Section 4.2.6 in the CBA Framework):

> *Hybrid approaches combine elements of both the deterministic and probabilistic approaches. The baseline release volume, the reduced release volume and the failure rate are fixed-point constant values. However, unlike deterministic approaches, these values are calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variables. Hybrid approaches differ from probabilistic approaches in that the calculations are not based on reported or assumed flaws and, therefore, structural reliability models and ILI data are generally not required. Rather, they are based on assumed random variables (hole size distribution, release pressures, etc.) inferred from historical incident data. As a result, it is not possible to directly estimate the temporal distribution of failures; as with deterministic approaches, this must be assumed later for discounting purposes. Similarly, the failure rate is not implicitly accounted for and must be estimated later with a separate process.*

The adopted process and methods used in calculating, and later combining, each of the identified key components using the hybrid approach are discussed in detail in the following subsections:

A.4.2.2 Baseline Release Volume

The CBA Framework defines baseline release volume as follows (refer to Section 4.2.2. in the CBA Framework):

> *The baseline release volume represents the expected release volume, given the occurrence of a pipeline release, absent deployment of the proposed ELD system(s). In the absence of an ELD system, it is assumed that all pipeline releases are eventually detected by either the public, a third-party contractor, a pipeline employee, a CPM system or some other source that is unrelated to the performance of an ELD system. The baseline release volume is estimated by determining the volume of product that will likely escape from a pipeline before it is detected by one of these means.*

Methods

The CBA Framework has identified two methods for estimating the baseline release volume. The first method, referred to in the CBA Framework as "direct method", consists of directly calculating or modeling the baseline release volume for a representative range of release conditions. With direct methods, specific models are required to accurately predict fluid migration through soil. The output from these models would then have to be combined with other information, such as expected population density, maintenance and inspection schedules, and CPM capabilities, to estimate at which point a given release is likely to be detected and how much volume has escaped between that moment and the instant the release began.

The second method, referred to in the CBA Framework as "inferred method", consists of inferring the baseline release volume from historical incident data, provided the incident database is sufficiently large and that it is reasonably representative of the pipeline under consideration. This approach is much simpler to implement than a direct approach, and doesn't require specialized data and models; however, the results obtained will not be as line-specific and/or accurate as those obtained by direct modeling.

In the absence of a well-established approach for directly calculating the subsurface fluid propagation and, therefore, the expected release volume for the demonstration analysis, the baseline release volume was estimated based on historical incident data (i.e. the inferred method).

Historical Incident Data

The historical incident data used in calculating the baseline release volume database comes from the 2010 to 2019 PHMSA Hazardous Liquid Pipeline Systems Accident Report (2). To ensure the calculated baseline release volume is reasonably representative of the demonstration pipeline, the database was filtered based on selected data fields, in accordance with the guidance provided in the CBA Framework. The resulting database was limited to release events originating from onshore pipelines that are deployed below ground and are transporting crude oil.

CPM Performance

A CPM system is assumed to be installed and operational on the demonstration pipeline. It is further assumed that the candidate ELD systems will operate in parallel with, but independently of, the CPM system and, therefore, will not influence the CPM system's performance and vice versa. The performance characteristics of the deployed CPM system are assumed to be consistent with typical systems installed on similar pipelines (i.e. underground, onshore, crude oil).

Consistent with the guidance provided in the CBA Framework, it is important to consider the possible effect of CPM systems when calculating the baseline release volume. In this regard, the CBA Framework provides the following guidance (refer to Section 4.2.2 in the CBA Framework):

> *When considering the possible effects of CPM or other complementary leak detection systems, there are two possible approaches. The first approach is to account for the effect of CPM implicitly in the incident reporting data. This involves filtering the incident data according to whether a CPM system is, or is expected to be, installed on the pipeline under consideration. For instance, if the pipeline under consideration is not expected to have a CPM system deployed, then the incident data should be filtered such that it only*

> *reflects entries which were not confirmed to have been detected with CPM. Conversely, if the pipeline under consideration is expected to have CPM deployed, then the incident data should be filtered such that it reflects only entries which were confirmed to have a CPM system deployed. This approach requires the database to contain data fields indicating both whether CPM was deployed and, if so, whether it was the basis for detection. This approach is simple to implement; however, it makes the implicit assumption that CPM performance is representative of the aggregated performance of the CPM systems as reported in the incident database…The other approach is to account for the effect of CPM explicitly by calculating the expected release volume for releases that exceed the CPM detection threshold based on the expected performance specifications of the CPM system being considered. This approach requires accurate information about the CPM system and its expected performance when it is deployed on the pipeline under consideration, as well as information about the pipeline's operation (i.e. the expected frequency and duration of shut-in events during which CPM is non-functional or has reduced performance).*

Given the stated assumptions and available data, it was decided that the best avenue by which to account for the performance of a CPM system is via the first approach as outlined in the CBA Framework.

In interpreting the incident data to assess CPM performance, consideration was given to three data fields: the first data field indicating whether or not CPM was confirmed to have been installed and functional at the time of the reported incident, the second data field indicating whether or not the reported incident was detected with CPM, and the third data field indicating the failure mode (i.e. leak or break). It was found that the proportion of reported releases that were detected by CPM, given CPM was confirmed to have been installed and functional at the time of the incident, is 4% for leaks and 67% for breaks[7] (or ruptures, as they are referred to in the PHMSA incident reporting database). This suggests that CPM, as portrayed in the PHMSA incident reporting database and subject to the adopted data field filters, is reasonably effective at detecting breaks but not leaks. Breaks are typically associated with large release rates, often on the order of the pipeline flow rate. Therefore, it was assumed that ELD systems are unlikely to be capable of offering significant improvements over existing CPM systems with regard to break detection. It was therefore decided that the most practical way of accounting for CPM performance would be to assume that breaks are readily detectable by the demonstration pipeline's CPM system, while other, smaller magnitude release events are not (i.e. CPM is 100% effective at identifying breaks

[7] In addition to leaks and ruptures, the PHMSA incident reporting database also reports mechanical punctures. It was assumed that the mechanical puncture label is usually assigned by operators to describe the initiating event and not necessarily to distinguish releases on the basis of hole size. The equivalent hole sizes (i.e. the diameter of a circular orifice having the same area as that of the reported mechanical puncture orifice) associated with mechanical punctures range from 0.3 to 26.7 inches with an average value of 4.2 inches. On that basis, it was assumed that mechanical punctures, like breaks, have a high likelihood of being detected by the demonstration pipeline's CPM system.

and 0% effective at identifying other smaller release events).[8] The baseline release volume is therefore based on incident data that excludes breaks (i.e. the PHMSA incident reporting database is further filtered to only include leaks, as defined in the PHMSA incident reporting database).

Distribution Fitting

Depending on the adopted general approach (i.e. deterministic, probabilistic or hybrid), the baseline release volume can either be a random variable following some statistical distribution or a deterministic value representing an average quantity. Calculation of the reduced release volume and the use of an impact attenuation factor in the adopted monetization model require the baseline release volume to be a random variable (the reduced release volume calculation approach is discussed in Section A.4.2.3 and the impact attenuation factor is introduced and discussed in more detail in Section A.4.2.5). An exponential distribution was found to fit the filtered incident data best and was, therefore, used to characterize the baseline release volume random variable. Normalized probability density functions (PDFs) comparing the historical baseline release volume data and the adopted exponential distribution function are shown in Figure A.4.1.

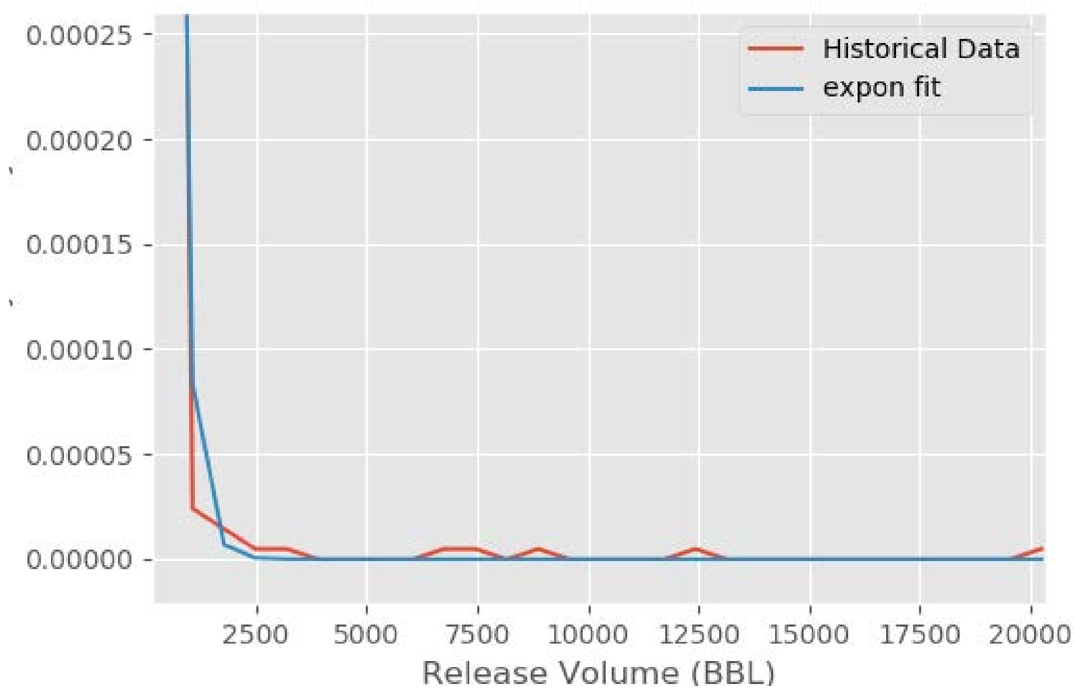

Figure A.4.1 Baseline Release Volume Distribution Fit

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[8] Note that this is not necessarily representative of current commercial CPM systems. Rather, given the information available and the interpretation of the incident reporting database, it represents the most practical way of accounting for CPM for the purpose of demonstrating the CBA Framework.

A.4.2.3 Reduced Release Volume

The CBA Framework defines reduced release volume as follows (refer to Section 4.2.3 in the CBA Framework):

> *The reduced release volume represents the release volume that would arise, given a release has occurred, assuming a particular ELD system were installed in a particular deployment configuration. Because ELD systems are relatively new and pipeline releases relatively rare, historical incident data describing reduced release volumes either doesn't exist or is critically limited. Accordingly, reduced release volume cannot be reliably inferred from historical data. The only viable approach is to estimate it directly using appropriate models and assumptions.*

The CBA Framework identifies two possible mechanisms by which ELD systems are able to reduce the expected release volume relative to the baseline release volume: reduced detection time and release frequency reduction. Release frequency reduction is predominantly achieved through additional ELD system functionality, such as encroachment detection, whereby the ELD system notifies operators of potential unauthorized third-party encroachment activities that risk damaging the pipeline. Since the candidate ELD systems are assumed not to have encroachment detection capabilities, reduced release volume is calculated by considering reduced detection time only.

In estimating the reduced release volume based on reduced detection time (or, more specifically, on an ELD system's ability to reduce the detection time of certain releases), the CBA Framework provides the following general guidance (refer to Section 4.2.3 in the CBA Framework):

> *ELD systems are able to alert pipeline operators of certain releases (i.e. those that fall within the ELD system's detection range) sooner than would otherwise be possible, thereby reducing the expected duration and volume of these releases. Reduced release volume is therefore based on an ELD technology's overall ability to reduce the time required to detect pipeline releases (i.e. reduced detection time). On that basis, reduced release volume is quantified by first identifying releases (or the expected proportion of releases) that fall within the ELD system's detection range (i.e. detectable releases). The associated release rates of the detectable releases are then calculated and multiplied by the overall response time (i.e. the ELD response time plus the operator response time). Depending on the adopted benefit calculation approach, the resulting volumes are either averaged or aggregated and fit to an appropriate statistical distribution.*

Determining whether or not a release is detectable and calculating the expected release volume of detectable releases requires information about the release magnitude, the ELD detection threshold, the ELD response time, the operator response time and the release rate. These topics are addressed in the following subsections.

ELD Response Time

The ELD system response time is defined in the CBA Framework as (refer to Section 4.2.3 in the CBA Framework):

> *…the time between the onset of a leak, and the moment at which point the leak has been discovered by the ELD system and communicated to the pipeline operator. ELD response time is a function of the ELD system's sensing mechanism, as well as the relevant pipeline attributes along the pipeline section being evaluated.*

The response time is assumed to be a fixed value independent of the releases rate or other release parameters, such as release pressure, orifice size, etc. The ELD vendors that provided guidance in establishing representative performance specifications reported their performance in this way. For the purpose of the demonstration exercise, the vendor performance was accepted at face value. In a real analysis, it might be prudent to obtain supporting data for the reported performance, and it might also be desirable to perform additional testing and evaluations if the supporting data has information gaps. A report prepared for PHMSA in 2018 provides detailed guidance for conducting an ELD technology market survey and for analyzing and interpreting the results (4).

Based on the stated assumptions, the assumed ELD response time is fixed for each combination of ELD technology and deployment configuration. The assumed values are provided in Table A.4.1.

Operator Response Time

Operator response time is defined in the CBA Framework as (refer to Section 4.2.3 in the CBA Framework):

> *…the time it takes the operator to respond to an ELD leak alarm and effectively stop the leak. Accurately characterizing operator response time requires information about: the nature of the ELD alarm itself (degree of supervisory control and data acquisition (SCADA) integration, personnel alerted, communication protocol etc.); alarm management strategies employed by the operating company; and certain pipeline attributes, specifically whether or not sections can be remotely isolated (i.e. shut in), the pipeline elevation profile, and the proximity and the level of accessibility to responders.*

With TAP guidance, a fixed operator response time of 2 hours was assumed for all releases. A more detailed analysis might consider a range of possible operator response times. Alternatively, the operator might choose to treat operator response time as a random variable following some underlying statistical distribution (i.e. similar to the orifice size, operating pressure and baseline release volume variables). However, for the purpose of demonstration, a fixed value was believed to be appropriate as it allowed for the operator response time variable to be more readily and intuitively evaluated in a sensitivity analysis (refer to Section A.5.2.4.1).

ELD Detection Threshold

The ELD detection threshold is defined in the CBA Framework as (refer to Section 4.2.3 in the CBA Framework):

> *…the smallest detectable leak that an ELD system can reliably detect without exceeding a prescribed false alarm rate. It is often defined in terms of well-known flow parameters, such as leak rate, but it can also be defined in terms of some combination of parameters… ELD detection threshold depends on the technology type and should be provided by the ELD technology vendor. In the absence of accurate information describing the ELD system's detection threshold, it might be necessary to obtain it by through additional experimental evaluations or numerical modeling.*

The detection threshold of the candidate ELD technologies is assumed to be a fixed value defined in terms of a release rate. Release rate is a common metric for describing the detection threshold of ELD systems and the ELD vendors that provided guidance in establishing representative performance specifications reported their performance in this way. Again, in a real analysis, it might be prudent to obtain supporting data for the reported performance and it might also be desirable to perform additional testing and evaluations if the supporting data has information gaps. A report prepared for PHMSA in 2018 provides detailed guidance for conducting an ELD technology market survey and for analyzing and interpreting the results (4).

Based on the stated assumptions, the assumed ELD detection threshold is fixed for each combination of ELD technology and deployment configuration. The assumed values are shown in Table A.4.1.

ELD Technology Type	Deployment Configuration	Detection Threshold (GPM)	Response Time
DAS	On Pipe	0.264	1 minute
	Near Field	1.321	1 minute
	Far Field	3.963	1 minute
VST	On Pipe	0.005	48 hours
	Near Field	0.005	24 hours
	Far Field	0.005	48 hours
DTS	On Pipe	3.963	3 minutes
	Near Field	2.642	6 minutes
	Far Field	6.604	10 minutes

Table A.4.1 ELD Performance by Technology Type and Deployment Configuration

Release Rate

Release rate is defined in the CBA Framework as (refer to Section 4.2.3 in the CBA Framework):

> *…the volumetric or mass flow rate of a given release. It is used in the calculation of the release volume for detectable releases. It can be expressed as a fixed value representing the average release rate over time or as a time varying value, which changes with evolving flaw geometry and pipeline operating conditions. Calculation of release rate requires representative distributions of expected hole sizes, driving pressures and other relevant parameters depending on the adopted leak rate expression.*

For the demonstration analysis the following simple expression for estimating the leak rate of single-phase liquid flow through a circular orifice was adopted:

$$Q = \frac{\pi C_d d^2}{4}\sqrt{\frac{2p}{\rho}} \qquad \text{[A.4.1]}$$

where C_d is the discharge coefficient, p is the driving pressure, d is the equivalent[9] orifice diameter and ρ is the product density.

The demonstration pipeline has the potential to generate a number of releases, ranging in size (i.e. d in Equation [A.4.1]) and driving pressure, over the course of its operational life span. Therefore, to account for the inherent uncertainty in the release rate of a given release event, it was decided to model orifice diameter and driving pressure as random variables following appropriate statistical distributions.[10]

The driving pressure was assumed to be equivalent to the internal pipeline pressure at the release location. Release pressure was assumed to follow a uniform distribution with values ranging from 100 to 500 psi, representing the range of operating pressures on the demonstration pipeline expected during normal operating conditions (refer to Section A.1 for details regarding the selection of the adopted operating pressure range).

The orifice size distribution was based on the historical incident data from the 2019 Performance of European cross-country oil pipelines report by Conservation of Clean Air and Water in Europe (CONCAWE) (5). The CONCAWE report by Cech et al. (5) was chosen because, compared to similar

[9] An equivalent orifice diameter is the diameter of a circular hole having the same surface area as that of a rectangular opening defined by a given length and width.

[10] Other parameters, namely product density and orifice discharge coefficient, are assumed not to vary as much as pressure and orifice diameter, and are, therefore, treated as fixed point values rather than random variables.

incident reporting databases, it was found to provide the most granularity in terms of orifice dimensions, specifically in the smaller ranges.[11]

It is important to note that only small leaks are considered in the benefit quantification exercise (i.e. ELD is not believed to offer significant opportunities to reduce break volume compared to what is already possible with the assumed CPM system—refer to Section A.4.2.2). Therefore, the following criteria for distinguishing small leaks from other releases were adopted:

- Orifice size threshold: Orifices having dimensions exceeding the width and length thresholds for pinholes and fissures as defined in the CONCAWE report by Cech et al. (5) are not considered in the simulation; and
- Release rate threshold: Releases with release rates exceeding 10%[12] of the assumed flow rate of the demonstration pipeline are not considered in the simulation.

Analysis Procedure

Consistent with the guidance provided in the CBA Framework and with the adopted hybrid approach, the above listed parameters and release categorization thresholds were used in the following stepwise procedure[13] to estimate the expected reduced release volume for each ELD technology and deployment configuration under consideration:

1. Generate a random realization consisting of random selections from the baseline release volume distribution, the orifice size distribution and the release pressure distribution.
2. Calculate the leak rate using the simplified leak rate expression and appropriate input parameters from the current realization (driving pressure, orifice diameter, fluid properties, etc.).
3. Compare the orifice dimensions and release rate of the current realization to the adopted break criteria.
    a. If the release rate exceeds the break release rate threshold, or if the orifice dimensions exceed the break orifice size threshold, then the current realization is assumed to be a break and, therefore, is not considered in the reduced release volume calculation (refer to Section A.4.2.2). Ignore this realization and return to Step 1 for a subsequent iteration.

[11] Lognormal distributions representing orifice width and length were fit to the hole size data from Cech et al. (6) via a numerically solved quantile-matching estimation approach.
[12] Other flow rate cutoffs are possible and may be more appropriate depending on the circumstances; however, a value of 10% was adopted for the purpose of demonstration.
[13] The calculation was performed programmatically using custom developed Python script.

b. If the release rate does not exceed the break release rate criteria, and the orifice dimensions do not exceed the break orifice size criteria, the release is assumed not to be a break and will, therefore, be used in the reduced release volume calculation. Proceed to the next step.

4. Compare the calculated leak rate to the ELD detection threshold.

   a. If the calculated leak rate is larger than the ELD detection threshold, the leak is considered to have gone undetected. The reduced release volume for the current realization is equivalent to the baseline release volume for the current realization. Record the reduced release volume and return to Step 1 for a subsequent iteration.

   b. If the calculated leak rate is greater than the ELD detection threshold, the leak is considered to have been detected by the ELD system. Calculate the reduced release volume for the current realization as follows:

$$V_{RED} = \min\left[V_{BL_i}, \left(Q_i \times t_{resp}\right)\right] \quad \text{[A.4.2]}$$

   where, V_{BL_i} is the baseline release volume for the i^{th} realization, Q_i is the leak rate for the i^{th} realization, and t_{resp} is the overall response time (i.e. the combined ELD response time and the operator reaction time).

   The presence of an ELD system is assumed not to negatively impact the natural, unassisted detection of leaks. In acknowledgement of this, a value of $Q_i \times t_{resp}$ that is larger than V_{BL_i} would indicate that ELD (or at least the ELD system under consideration) would not offer any significant advantage over the already existing passive leak detection strategies that are, or that are assumed to be, in place. The minimum function in Equation [A.4.2] is therefore necessary because it ensures that the reduced release volume never exceeds the associated baseline release volume for a given realization.

   Once the reduced release volume and associated baseline release volume for the current realization have been calculated, return to Step 1 for a subsequent iteration.

This procedure was repeated until 100,000 values of V_{RED_i} and V_{BL_i} were calculated (i.e. $\max(i) = 100{,}000$) for each of the candidate ELD technologies and identified deployment configurations. (The array of values comprising V_{RED} and V_{BL} are later used in combination with other parameters to estimate the expected monetized benefit per mile-year.) The required number of simulations (i.e. the simulation count) was determined by running a convergence test whereby various monetized benefit values were calculated (refer to Section A.4.3) using different simulation counts. Simulation counts in the range of 100,000 are associated with an average relative change in the monetized benefit value of only 0.4% with a maximum value of only 2%. This was deemed acceptable and, therefore, a target simulation count of 100,000 was used.

A.4.2.4 Failure Rate Estimate

Failure rate is defined in the CBA Framework as follows (refer to Section 4.2.4 in the CBA Framework):

> *Failure rate is the expected probability of a pipeline release (i.e. failure) occurring within a prescribed time period (typically one year) over some fixed length of pipeline. There are several approaches for estimating the expected failure rate of a pipeline. The different approaches are generally classified as being either qualitative or quantitative in nature, where the estimated failure rate is measured on subjective and objective scales, respectively. In estimating benefits for the purpose of conducting a CBA, the desire is to objectively characterize potential benefits in equivalent dollar terms. To this end, the guidance provided in this section will focus on quantitative approaches for estimating failure rate.*

The CBA Framework recognizes three general approach categories for quantitatively estimating pipeline failure rates: SME opinion, historical failure data, and engineering models and reliability analysis methods. Given the available information for the demonstration pipeline, it was decided that the best avenue for calculating the expected failure rate is through historical failure data. In estimating the failure rate from historical incident data, the overall pipeline failure rate estimate is calculated by dividing the number of incidents occurring in a given time period (i.e. one year) by the annual exposure (i.e. the total mileage of pipeline over which the incidents are aggregated), and finally averaging this outcome over several years as follows:

$$F = \left[\sum_{N_{years}}^{i=1} \left[\frac{N_{leaks_i}}{m_i}\right]\right] \frac{1}{N_{years}} \qquad \text{[A.4.3]}$$

where F is the expected failure rate expressed in units of leaks per unit length per year (i.e. leaks/mile-year), N_{leaks_i} is the total number of releases occurring in the i^{th} year, m_i is the total pipeline mileage in the i^{th} year and N_{years} is the total number of years over which the leak frequency calculation is averaged. In determining N_{leaks_i} and m_i, the following databases were used:

- 2010 to 2019 PHMSA Hazardous Liquid Pipeline Systems Accident Report (2)—used in the calculation of N_{leaks_i}
- Annual Report for Calendar Year 2019 Hazardous Liquid Pipeline Systems (1)—used in the calculation of m_i

Given the stated assumptions, the expected failure frequency of 6.4×10^{-4} leaks per mile-year is calculated by substituting the values for N_{leaks_i} and m_i for years 2010 to 2019 into Equation [A.4.3] as follows:

$$F = \left[\frac{31}{49{,}460} + \frac{29}{51{,}051} + \frac{30}{52{,}657} + \frac{57}{56{,}170} + \frac{60}{61{,}888} + \frac{45}{67{,}895} + \frac{49}{70{,}610} + \frac{37}{74{,}071} + \frac{36}{74{,}742} + \frac{25}{78{,}460}\right] \times \frac{1}{10} = 6.4 \times 10^{-4}$$

The expected failure frequency calculated in Equation [A.4.3] excludes breaks (refer to Section A.4.2.2).

A.4.2.5 Monetization Model

The purpose of the monetization model is to provide a means by which to convert the expected release volume reduction into an environmental protection enhancement measure that is expressed in equivalent dollar terms. The CBA Framework provides the following general guidance in selecting and applying an appropriate monetization model (refer to Section 4.2.5 in the CBA Framework):

> *…different approaches are recommended depending on whether the dominant environmental threat associated with the transported substance relates to GHG emissions or environmental damage resulting from exposure to persistent liquids…*

The substance transported by the demonstration pipeline is assumed not to contribute significantly to global warming; however, it is assumed to remain in a liquid state following release and to persist in the environment if it is not recovered. The adopted approach for calculating enhancement measures is based on previous work in which a model capable of assessing the combined socioeconomic and environmental impact of low vapor pressure (LVP) hydrocarbon liquid product spills from onshore pipelines was developed (6). This spill impact formula takes the following form:

$$C = \beta V^{\alpha} \qquad \text{[A.4.4]}$$

where β is a location factor reflecting the relative damage sensitivity and importance of the environment affected by the release, V is the release volume and α is the so-called impact attenuation factor, which characterizes the degree of proportionality between the magnitude of the of spill impact and the total volume spilled. Based on the analysis described in Stephens and Etkin (6), an impact attenuation factor of 0.8 is recommended.

The results obtained using Equation [A.4.4] are meant to reflect spill impacts in relative terms. Calculating the absolute spill impact therefore involves multiplying the relative spill impact obtained using Equation [A.4.4] by an additional factor, c_r, representing the spill impact associated with a reference spill involving a specified release of a given product in a specific location.

For the purpose of monetizing the impact of a hydrocarbon liquid release, it can be assumed that the aggregated costs associated with spill clean-up, site restoration and compensation paid to parties experiencing financial losses because of the spill serves as a reasonable proxy for the dollar cost equivalent of the environmental damage and any associated socioeconomic impact caused by a spill. Based on regression analysis of the equivalent dollar cost of a range of hypothetical and real hydrocarbon liquid spills (6,7,8), a unit cost in the range of $200,000 to $300,000 per cubic meter (or in the range of $30,000 to $50,000 per bbl) is suggested for use as the unit cost of a spill at the reference location, defined as a location with a beta factor of 1.0. An assumed reference spill impact value of 40,000 USD/bbl was therefore used in the simulation.[14]

The assumed locations traversed by the demonstration pipeline are broadly categorized as either high consequence areas (HCAs) or non-HCAs. HCAs are assumed to consist primarily of designated high population areas, areas associated with designated drinking water resources, or areas associated with designated ecological resources. Non-HCAs are assumed to consist primarily of forested areas, grassland or rangeland, and agricultural areas. Each of the listed location sub-categories were assigned a location factor,[15] as well as a percentage of total pipeline mileage within each respective location category. The assumed mileage percentages are based on USDA land use data for dominant land uses in the continental US (9) and US hazardous liquid pipeline mileage statistics for 2010 provided by PHMSA through NPMS (10). Mileage-weighted, average location factors for both location categories were calculated and are summarized, along with the assumed mileage percentages and sub-category location factors, in Table A.4.2.

[14] It is acknowledged that a unit cost range using a higher estimate of the equivalent dollar cost of a liquid hydrocarbon release may be appropriate for releases that could impact culturally significant areas.

[15] These factors were developed using the categorization model developed by Stephens and Etkin (6). They are based on regression analysis of cost data obtained from detailed impact cost studies for a large number of real and hypothetical spills on land and water.

Location Category	Location Sub-category	Location Factor	Percentage of Mileage Within Respective Location Category	Mileage-weighted Location Factor
Non-HCA	Forest	1.3	36%*	1.5
	Grassland/rangeland	1.3	37%*	
	Agricultural	2.0	27%*	
HCA	High Population Area	4.2	47%†	4.5
	USA – drinking water resource	4.2	30%†	
	USA – ecological resource	5.4	23%†	

* USDA (9)
† NPMS-PHMSA (10)

Table A.4.2 Assumed Location Factors for Demonstration Pipeline

Annual monetized benefit values, assuming ELD deployment in both HCA and non-HCA locations, were calculated using Equation [A.4.4]. Per Table A.4.2, an average location factor of 4.5 was assumed for HCA locations, and an average location factor of 1.5 was assumed for non-HCA locations. These results were later used in the scenario sensitivity analysis outlined in Section A.5.

A.4.3 Results and Conclusions

Figure A.4.2, Figure A.4.3 and Figure A.4.4 represent histograms comparing the baseline and reduced release volumes associated with the best performing (i.e. highest expected annual benefit) deployment configurations for the candidate DAS, VST and DTS technology vendors, respectively. The baseline release volumes (plotted in blue) consist of N random samples taken from the baseline release volume distribution function (refer to Section A.4.2.2), where N is the total number of realizations used in the discussed hybrid approach. The reduced release volumes (plotted in orange) consist of the calculated reduced release volumes for each of the N realizations.

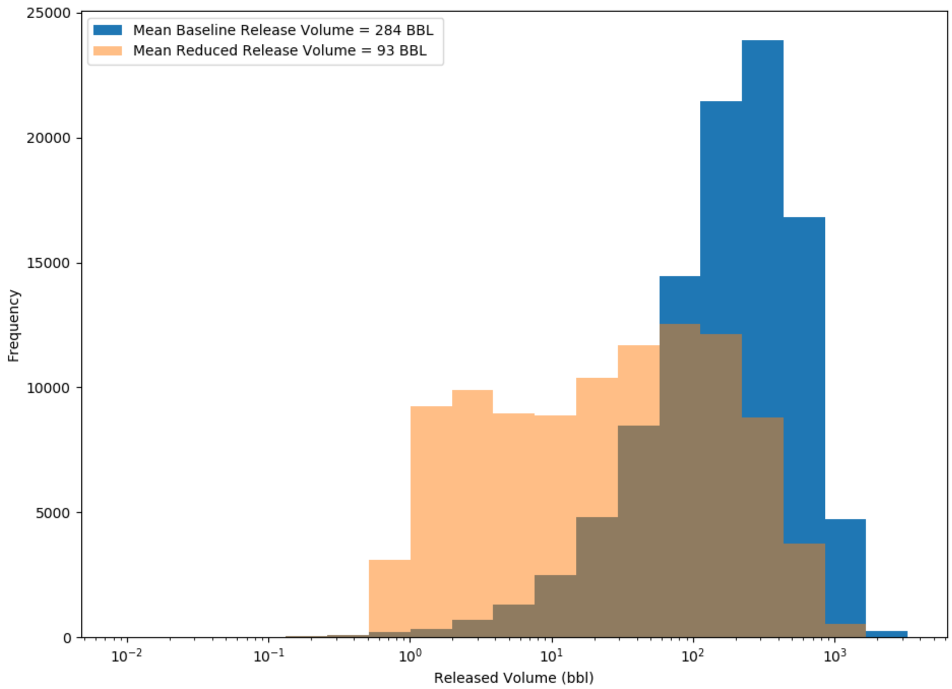

Figure A.4.2 Histogram of Baseline and Reduced Release Volumes for DAS – On Pipe Deployment Configuration

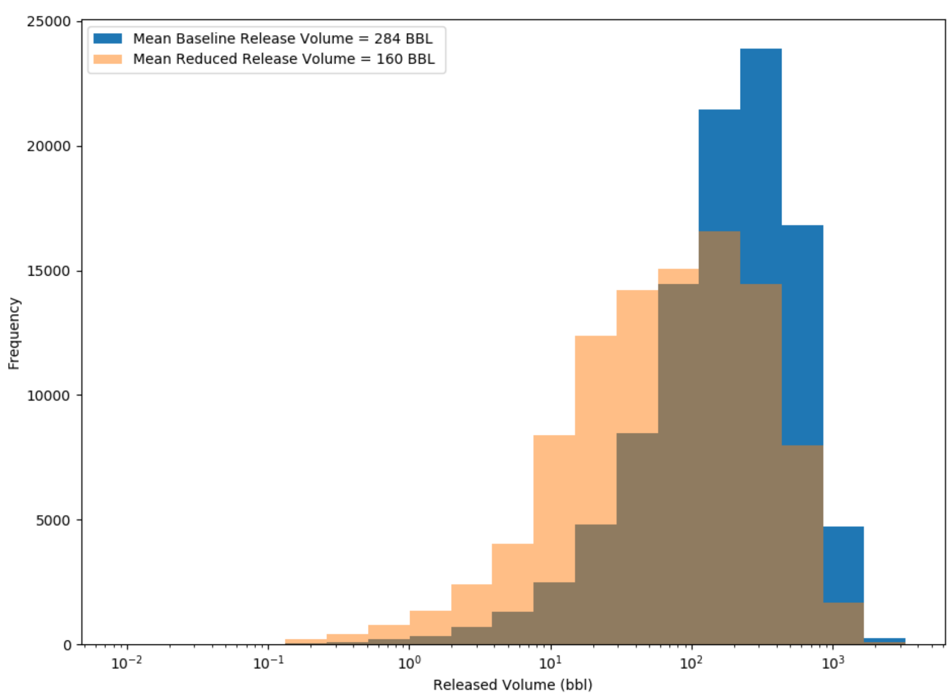

Figure A.4.3 Histogram of Baseline and Reduced Release Volumes for VST – Near Field Deployment Configuration

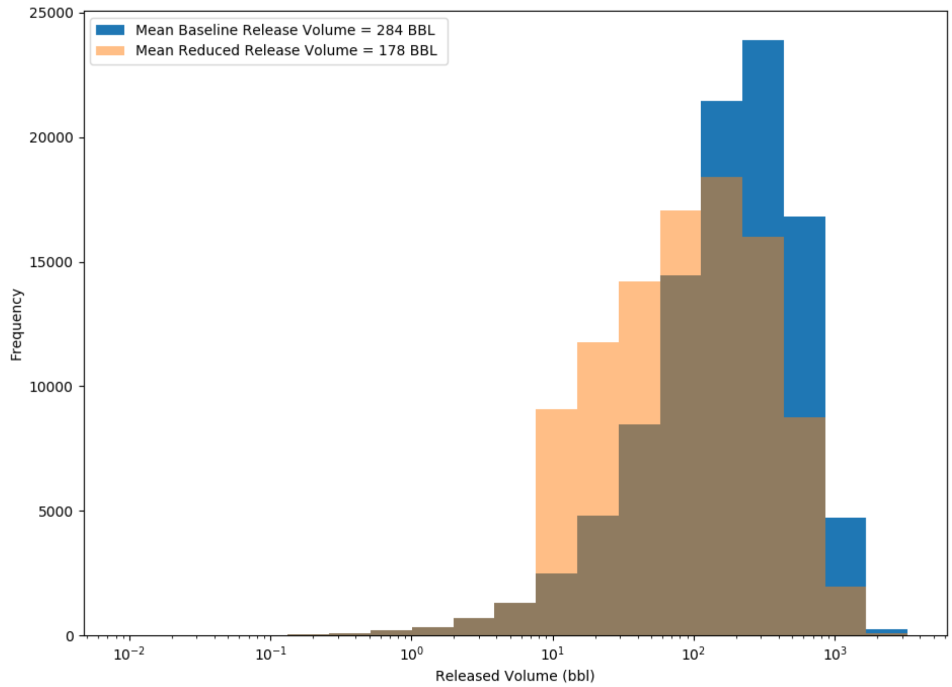

Figure A.4.4 Histogram of Baseline and Reduced Release Volumes for DTS – Near Field Deployment Configuration

These histograms help to show how ELD implementation is expected to alter the release volume distribution and lead to an overall reduction in release volume. Higher release volume reductions correspond to reduced release volume distributions with values that are more concentrated to the left of the figure (i.e. Figure A.4.2), whereas less significant release volume reductions are associated with reduced release volume distributions that more closely resemble the baseline release volume distribution (i.e. Figure A.4.3).

To express the benefit of the environmental impact reduction afforded by reduced spill volumes in monetary terms using the adopted monetization model that employs an impact attenuation factor, α (implying that the dollar equivalent of the impact is not a linear function of spill volume), the baseline and reduced release volumes had to be subtracted and exponentiated for each realization. Only after the differences in the spill impact were calculated for all realizations could they be averaged and multiplied by the leak likelihood and reference spill values to obtain the expected monetized benefit per mile-year.[16] This is expressed mathematically as follows:

[16] Similar to the release volume reduction calculation, this was calculated programmatically using a custom-developed Python script.

$$BENEFIT = F \times c_r \times \beta \times \frac{\sum_{N}^{i=0}({V_{BL}}_i^{\ \alpha} - {V_{RED}}_i^{\ \alpha})}{N} \qquad [A.4.5]$$

where, F is the expected failure rate, c_r is the reference spill impact value, β is the location sensitivity factor, N is the total number of simulations performed for each scenario, ${V_{BL}}_i$ and ${V_{RED}}_i$ are the expected baseline and reduced release volumes for the i^{th} realization, respectively, and α is the spill attenuation factor. The expected annual benefit values, calculated with Equation [A.4.5], for each of the candidate deployment configurations in both HCAs and non-HCAs are summarized in Table A.4.3 and compared graphically in Figure A.4.5.

Deployment Configuration	Location Type	Average Reduction in Release Volume (BBL/Release)	Expected Annual Benefit (USD/mile-year)
DAS – On-pipe	Non-HCA	191	2,388
DAS – On-pipe	HCA	191	7,150
DAS – Near Field	Non-HCA	131	1,590
DAS – Near Field	HCA	131	4,785
DAS – Far Field	Non-HCA	95	1,126
DAS – Far Field	HCA	95	3,397
VST – On-pipe	Non-HCA	102	1,221
VST – On-pipe	HCA	102	3,360
VST – Near Field	Non-HCA	124	1,507
VST – Near Field	HCA	124	4,522
VST – Far Field	Non-HCA	102	1,221
VST – Far Field	HCA	102	3,360
DTS – On-pipe	Non-HCA	95	1,121
DTS – On-pipe	HCA	95	3,366
DTS – Near Field	Non-HCA	106	1,266
DTS – Near Field	HCA	106	3,801
DTS – Far Field	Non-HCA	77	893
DTS – Far Field	HCA	77	2,671

Table A.4.3 Benefits Summary for Preferred Deployment Configurations

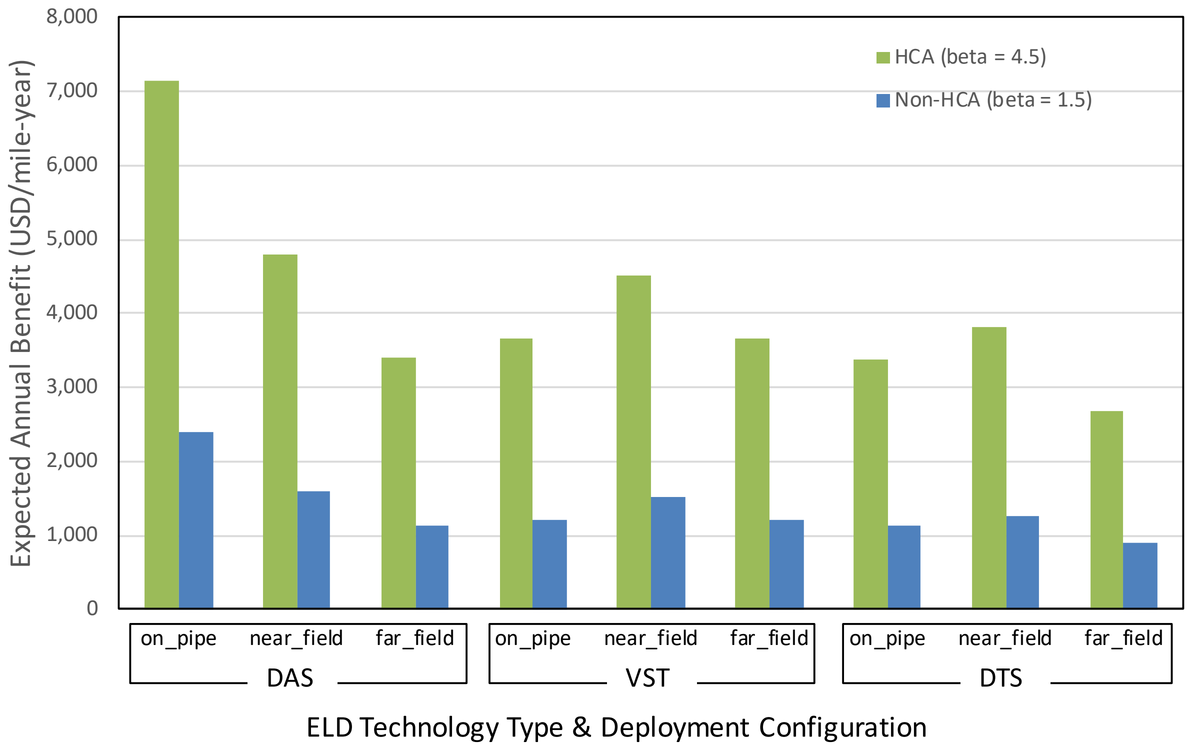

Figure A.4.5 Expected Annual Benefit per Mile for Preferred Deployment Configurations

The deployment configuration associated with the highest expected annual benefit is the DAS – On Pipe configuration in an HCA, and the deployment configuration associated with the lowest expected annual benefit is the DTS – Far Field configuration in a non-HCA. However, it should be noted that the reported benefit values do not represent the final deployment configuration rankings. These will be based on the results of the CBA. These findings are highly dependent on the analysis assumptions made, many of which were made to facilitate the demonstration analysis. Therefore, the expected benefit values listed in Table A.4.3 and illustrated in Figure A.4.5 should not be interpreted to suggest that one vendor's technology is superior to that of the other. Rather, the results should be interpreted to suggest that, given the information available, and with reference to the specific conditions that pertain to the demonstration pipeline, some ELD technologies are better suited to producing environmental protection benefits in specific locations.

In the subsequent section, the calculated expected annual benefits associated with the preferred deployment configurations will be distributed throughout the expected operational life of the demonstration pipeline and compared to the costs obtained in Section A.2 using the cost-benefit process outlined in the CBA Framework.

A.5. COST-BENEFIT ANALYSIS

A.5.1 Overview

The objective of this section is to combine the calculated costs and benefits derived in Sections A.3 and A.4 into an evaluation metric that can be used to objectively compare different ELD deployment alternatives for the purpose of decision making.

In the following sections, the process and methodology used in the CBA are reviewed and a summary of the results obtained from the analysis is provided.

A.5.2 Process and Methodology

A.5.2.1 Overview

The general CBA procedure outlined in the CBA Framework consists of the following key elements:

- Discounting: The present-day equivalent dollar value of both the benefits and costs is calculated using an appropriate discount rate and discounting approach.
- Evaluation Criteria: A method for combining the present-day costs and benefits into a cost benefit measure, which can serve as an objective basis for deployment configuration ranking and decision making, is chosen and implemented.
- Sensitivity Analysis: A sensitivity analysis is performed to examine how the present-day costs and benefits and, ultimately, the adopted cost-benefit measure change with variations in inputs and assumptions.

The adopted process and methods used in calculating each of the identified key elements are discussed in detail in the following subsections:

A.5.2.2 Discounting

Discounting is defined in the CBA Framework as follows (refer to Section 5.2 in the CBA Framework):

> *Discounting is a process that is used to compare costs and benefits that are incurred at different points in time. Costs and benefits occurring at different times should be adjusted so they reflect their value at a reference point in time, usually the present time. This is especially important if the analysis takes place over extensive time horizons, such as in the case of pipelines. The premise of discounting is based on the principle that people usually prefer to receive goods and services now rather than later (i.e. time preference). Generally, societies are assumed to grow wealthier over time; therefore, discounting also accounts for economic growth.*

Before discounting can be properly implemented in a CBA, it is important to first establish the following, per the guidance provided in the CBA Framework:

- The type of discount rate used (i.e. private or social);
- The temporal distribution of costs (i.e. placing the costs in time);
- The temporal distribution of benefits (i.e. placing the benefits in time); and
- The different discounting approaches.

A.5.2.2.1 Discount Rate

Consistent with the guidance provided in the CBA Framework, a social discount rate, rather than a private discount rate, was adopted. The CBA Framework provides the following guidance with regard to social versus private discount rates (refer to Section 5.2.1 in the CBA Framework):

> *When the objective of a CBA is to consider the costs and benefits of a policy or project for society at large, then the social discount rate is the appropriate choice. If, however, the objective of a CBA is to justify an investment opportunity by simply estimating the private cost to the investment provider, then a private discount rate is perhaps more appropriate. While pipelines are typically owned and operated by private agents, it is important to recognize that there is a social cost associated with private agents whose operations have the potential to impact society at large. In the case of ELD implementation on a pipeline asset, most of the potential benefits can be expressed as an expected reduction in the undesirable burden on society (i.e. fatality, injury, environmental damage). In this light, social discounting is believed to be the most appropriate approach for the purpose of conducting CBA for ELD implementation on a pipeline…*

A fixed nominal discount rate of 3% was chosen for the demonstration exercise. This is consistent with the literature, which reports practical social discount rates in the range of 2.5 to 5.5% (11,12,13). Note that the effect of alternative discount rates is explored in the sensitivity analysis (refer to Section A.5.2.4).

A.5.2.2.2 Temporal Distribution of Costs

It is important to properly place costs associated with ELD deployment in time with as much accuracy as possible to ensure that they can be properly discounted into present-day dollar equivalents. This subsection addresses temporal placement for costs in each of the cost categories identified in Section 3 of the CBA Framework.

Procurement and Installation

The demonstration pipeline is a new-construction pipeline; therefore, procurement and installation of the candidate ELD systems is assumed to occur concurrently with pipeline construction and is assumed to be complete prior to pipeline operation. The total procurement and installation costs associated with the candidate ELD systems are, therefore, incurred prior to the first year of pipeline operation.

Operation and Maintenance

Maintenance costs[17] are assumed to be uniformly distributed throughout the operational life of the pipeline. A more realistic assumption would be to account for aging equipment and assume gradually increasing maintenance costs over time. However, reliable information about the increase in maintenance costs over time was not available. Furthermore, because of the effect of discounting, future costs are less important than current costs and, therefore, a uniform maintenance cost distribution is more conservative compared to a rear-loaded maintenance cost distribution (assuming the total, pre-discounted maintenance costs in each scenario are equivalent).

Responding to False Alarms

The candidate ELD technologies are assumed not to produce false alarms. This assumption is based on information provided by the ELD vendors consulted, which provided guidance in selecting representative performance specifications (refer to Section A.2.2.2). For the purpose of the demonstration exercise, the vendor performance was accepted at face value. In a real analysis, it might be necessary to obtain supporting data for the reported performance, and to perform additional testing and evaluations if the supporting data has information gaps. Bussière et al. (4) provides detailed guidance for experimentally evaluating ELD performance.

Interference with Pipeline Operations

Interference with pipeline operations was assumed to be small and was, therefore, ignored.

A.5.2.2.3 Temporal Distributions of Benefits

As with costs, it is important to properly place potential benefits in time with as much accuracy as possible to ensure that they can be properly discounted into present-day dollar equivalents.

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[17] The adopted maintenance costs are assumed to include both episodic and periodic costs (refer to the CBA Framework).

Characterizing the temporal distribution of expected benefits is based on the following key considerations:

ELD System Performance

The candidate ELD systems are assumed to be operational prior to the demonstration pipeline's first year of operation (i.e. Year 1). The VST and DTS systems are assumed to be optimized and performing at their full potential in the first year of operation, whereas the DAS system is assumed to require a two-year ramp-up period, during which time system performance is attenuated somewhat to reflect baselining and optimization. Specifically, the ELD response time is increased twofold and the ELD detection threshold is reduced by 50% during the ramp-up period (after the two-year ramp-up period, the DAS system is assumed to perform at its full potential).

Pipeline Failure Rate

While a pipeline's fitness-for-service may degrade as the pipeline ages, pipeline operators can, and generally do, take action to mitigate the effects of aging (i.e. via preventative maintenance and timely repairs based on periodic integrity assessments). A review of incidents reported to PHMSA from 2002 through 2009 found that 85% of reported incidents were not correlated to the pipeline's age (14). On that basis, the calculated failure rate (refer to Section A.4.2.4 for details regarding calculation of the failure rate) is assumed to be constant throughout the demonstration pipeline's operational life.

A.5.2.2.4 Discounting Approach

The CBA Framework identifies two common discounting methods for use in CBA:

- Present Value
- Annualized Values

The present value approach is the simplest and most informative of the two approaches. It is often used in scenarios where CBA is used to evaluate an immediate investment, which offers an array of highly variable future benefits. On that basis, the present value discounting approach was adopted in the demonstration exercise. The CBA Framework describes the present value discounting approach as follows (refer to Section 5.2.4 in the CBA Framework):

> *The present value of an expected array of current and future benefits and costs is calculated by multiplying the benefits and costs in each year by a time-dependent weight, and adding all of the weighted values…*

Present value discounting is expressed mathematically as follows, assuming that $t = 0$ designates the beginning of the first period:

$$PVB = \sum_{t=0}^{n} B_t d_t \qquad [A.5.1]$$

$$PVC = \sum_{t=0}^{n} C_t d_t \qquad [A.5.2]$$

where the aggregated present value of current and future benefits is given by *PVB*, the aggregated present value of current and future costs is given by *PVC*, the current year is given by *t*, the duration of the analysis is given by *n*, the total benefit and total cost associated with year *t* is given by B_t and C_t respectively, and the discounting weights for a given year, *t*, and discount rate, *r*, are given by:

$$d_t = \frac{1}{(1+r)^t} \qquad [A.5.3]$$

Because the estimated failure rate is assumed to be constant over the demonstration pipeline's operating life, and because the candidate ELD systems are assumed to be fully operational in year zero (refer to Section A.5.2.2.3), the total benefit B_t for any given year, t, is constant. By comparison, the total cost, C_t, is different in year zero (reflecting the upfront ELD procurement and installation costs) and constant for the remaining operating life of the demonstration pipeline (refer to Section A.5.2.2.2).

A.5.2.3 Evaluation Metric

Once the costs and benefits have been discounted into present-day dollars, it is possible to combine them into a cost-benefit evaluation metric that can serve as an objective basis for deployment configuration ranking and decision making. The CBA Framework identifies the following approaches for deriving a suitable cost-benefit evaluation metric, with the most appropriate method (or methods) depending on the available information and the intended application:

- Net present value (NPV), defined as the arithmetical difference between the present benefits and the present costs (i.e. $PVB - PVC$);
- Benefit-cost ratio (BRC), defined as the ratio obtained by dividing the present benefits by the present costs (i.e. PVB/PVC); and
- Cost effectiveness ratio (CER), defined as the ratio of the present value of costs (i.e. *PVC*) to the total benefits expressed in non-monetary units.

The CBA Framework provides the following guidance to assist with the selection of an appropriate evaluation metric (refer to Section 5.3.2 in the CBA Framework):

NPV is usually the most informative and, therefore, the recommended cost-benefit measure for identifying a preferred alternative because it measures the true contribution of a project to economic welfare. However, a potential limitation with NPV relates to its inability to express the relative magnitude between the benefits and the costs. This is important when alternatives with significantly different budgets are being compared (i.e. when the magnitude of the expenditures between two or more alternatives are significantly different). This is especially problematic, when the resulting NPVs are similar in magnitude and when the uncertainty in the calculated present values is high.

The benefits and costs being considered are expressed in equivalent dollar terms; therefore, consistent with the guidance provided in the CBA Framework, NPV is adopted as the primary CBA evaluation metric. However, the inherent uncertainty in some of the input parameters (installation costs, failure rates, CPM performance, etc.) and, therefore, also in the calculated *PVC* and *PVB* values is relatively high. Hence, rather than rely on NPV alone, BCR will be used as an additional evaluation metric to evaluate possible alternatives that might yield similar NPVs. The CBA Framework, provides the following guidance with regard to using both NPV and BCR evaluation metrics together (refer to Section 5.3.2 in the CBA Framework):

in the absence of accurate uncertainty ranges, as is often the case with CBA, BCR can be used to evaluate alternatives with similar NPVs when there are significant differences in their overall budgets. BCR does, however, suffer from its own limitations. For instance, because it does not consider the scale of the expenditures involved, a highly profitable, small venture might be preferred over a much larger venture that is less profitable per dollar spent, but that would produce far more absolute profit. Furthermore, BCR is also highly sensitive to the manner in which certain costs, particularly recurrent costs, are accounted for, specifically, whether they are subtracted from the benefits or added to the costs (NPV is unaffected by this decision and, therefore, more robust in this respect). Given the limitations associated with BCR, it is generally not recommended to use as the sole cost-benefit measure in a given analysis, but rather it is recommended to use it in addition to NPV in certain scenarios.

A.5.2.4 Sensitivity Analysis

The CBA Framework provides the following guidance regarding the purpose of a sensitivity analysis in CBA (refer to Section 5.4.1 in the CBA Framework):

The primary purpose of the sensitivity analysis is to gain a better understanding of the effects of uncertain variables on the outcomes that are intended to inform decisions regarding ELD deployment. Sensitivity analysis involves changing selected variables and considering how the change affects the outcome (i.e. the adopted evaluation metric or metrics). The variables that are subject to being changed in a sensitivity analysis could include the input parameters themselves or the underlying assumptions upon which the input parameters are based (e.g. whether CPM is assumed to be deployed on the *pipeline, whether the ELD system is subject to a performance ramp up period, or whether maintenance costs are uniformly distributed in time).*

Consistent with the guidance provided in the CBA Framework, two types of sensitivity analysis were conducted: single variable testing and scenario analysis. Single variable testing provided a means for rapidly identifying the parameters that have the greatest impact on the adopted evaluation metric. The results were then used to inform which input parameters required additional or more detailed information, as well as what assumptions might need to be revisited or assessed more critically. Scenario analysis was intended to evaluate discrete scenarios representing the different deployment configurations identified in Section A.2 as well as variations of these scenarios involving different area sensitivity levels. Details regarding each of the sensitivity analyses performed are provided in the following subsections:

A.5.2.4.1 Single Variable Testing

Single variable testing is defined in the CBA Framework as follows (refer to Section 5.4.2 in the CBA Framework):

> *Single variable testing involves varying the input parameters, or analysis assumptions, one at a time while holding all other parameters and assumptions constant. Single variable testing is useful for rapidly identifying parameters with the greatest impact on the adopted evaluation metric. The results of this analysis could be used to inform which input parameters might require additional or more detailed information, as well as what assumptions might need to be revisited or assessed more critically.*

The variables subject to change in the single variable testing analysis include the following:

- Operator response time,
- Maximum release pressure,
- Pipeline length,
- Pipeline flow rate,
- Pipeline operating life, and
- Discount rate.

Consistent with the guidance provided in the CBA Framework, these variables were altered by fixed quantities relative to a base case one at a time while holding all other variables fixed. The resulting percent change in BCR (relative to the base case) was then recorded for each variation. The base case input parameters are based on the demonstration attributes (refer to Section A.1.3) and are summarized in Table A.5.1.

Parameter	Value
Operator Response Time	2 hours
Release Pressure Range	100 to 500 psi
Pipeline Length	155 miles
Pipeline Flowrate	19,800 GPM
Pipeline Operating Life	50 years
Spill Impact Attenuation Factor	0.8
Discount Rate	3%

Table A.5.1 Base Case Model Parameters Used in Sensitivity Analysis

Effort was focused in the sensitivity analysis on input parameters having non-trivial relationships with the evaluation metrics. The following parameters were therefore not included in the single variable testing analysis:

- The location factor, β;
- The reference spill impact value, c_r; and
- The initial ELD costs.

The effect of potential uncertainty in these parameters was not ignored; it was assessed in the same way as the other input parameters. However, the impact of this uncertainty could be quantified with simple arithmetic and did not require iterative numerical solutions.

A.5.2.4.2 Scenario Analysis

Scenario analysis is defined in the CBA Framework as follows (refer to Section 5.4.2 in the CBA Framework):

> *Scenario analysis involves defining a number of alternative situations in which different combinations of input parameters and assumptions are evaluated. The different alternatives should be based on likely situations that may occur, such as: different deployment configurations, or deployment in a high-consequence area versus an area that is not deemed highly sensitive. Scenario analysis may also be used to evaluate best- and worst-case scenarios and to subsequently build an interval representing the extreme range of possible outcomes. The results of a single variable testing analysis could be used to inform which parameter values to use in the best- and worst-case scenarios.*

Consistent with the guidance provided in the CBA Framework, the different alternatives explored in this scenario analysis are based on the following:

- The nine deployment configurations identified in Section A.2; and
- The two area sensitivity levels introduced in Section A.4.2.1 (i.e. a non-HCA characterized by an average location factor of $\beta = 1.5$ and an HCA characterized by an average location factor of $\beta = 4.5$).

The fixed model parameters (i.e. model parameters common to each of the explored alternatives) are summarized in Table A.5.1. The different alternatives evaluated in the scenario analysis and the corresponding parameters variations are summarized in Table A.5.2.

Alternative No.	Deployment Configuration	Location Type	ELD Detection threshold (GPM)	ELD Response Time	ELD Initial Costs (USD/mile)	Recurring Costs (USD/mile-year)
1	DAS – On Pipe	Non-HCA	0.264	1 minute	136,794	2,414
2	DAS – On Pipe	HCA	0.264	1 minute	136,794	2,414
3	DAS – Near Field	Non-HCA	1.321	1 minute	104,607	2,414
4	DAS – Near Field	HCA	1.321	1 minute	104,607	2,414
5	DAS – Far Field	Non-HCA	3.963	1 minute	72,421	2,414
6	DAS – Far Field	HCA	3.963	1 minute	72,421	2,414
7	VST – On Pipe	Non-HCA	0.005	48 hours	142,459	32
8	VST – On Pipe	HCA	0.005	48 hours	142,459	32
9	VST – Near Field	Non-HCA	0.005	24 hours	102,226	32
10	VST – Near Field	HCA	0.005	24 hours	102,226	32
11	VST – Far Field	Non-HCA	0.005	48 hours	61,992	32
12	VST – Far Field	HCA	0.005	48 hours	61,992	32
13	DTS – On Pipe	Non-HCA	3.963	3 minutes	140,013	1,609
14	DTS – On Pipe	HCA	3.963	3 minutes	140,013	1,609
15	DTS – Near Field	Non-HCA	2.642	6 minutes	107,826	1,609
16	DTS – Near Field	HCA	2.642	6 minutes	107,826	1,609
17	DTS – Far Field	Non-HCA	6.604	10 minutes	75,639	1,609
18	DTS – Far Field	HCA	6.604	10 minutes	75,639	1,609

Table A.5.2 Alternatives Evaluated in the Scenario Analysis

A.5.3 Results and Conclusions

A.5.3.1 Single Variable Testing

The single variable testing sensitivity analysis described in Section A.5.2.4.1 was performed for each of the preferred deployment configurations. Figure A.5.1 though Figure A.5.6 show the percent change in BCR values and NPVs relative to the base case as a function of incremental variations in selected input parameters for each of the preferred deployment configurations. In most cases, the percent change in BCR provides a clearer understanding of the effects of varying the input parameters compared to the percent change in NPV. The sensitivity curves based on the BCR values tend to collapse more readily for a given ELD technology, thereby revealing trends more easily. This is because the percent change in NPV is highly sensitive to the base case NPV. Specifically, the closer the base case NPV is to zero (or equivalently, the closer the base case BCR value is to unity), the more exaggerated the percent change in NPV will be. On that basis, the findings, with respect to the single variable testing analysis, will be informed primarily based on the BCR sensitivity curves. In some cases, the NPV sensitivity curves are more informative and will, therefore, be used in place of the BCR curves. The results of the single variable testing analysis for each of the input parameters are reviewed and discussed in the following paragraphs.

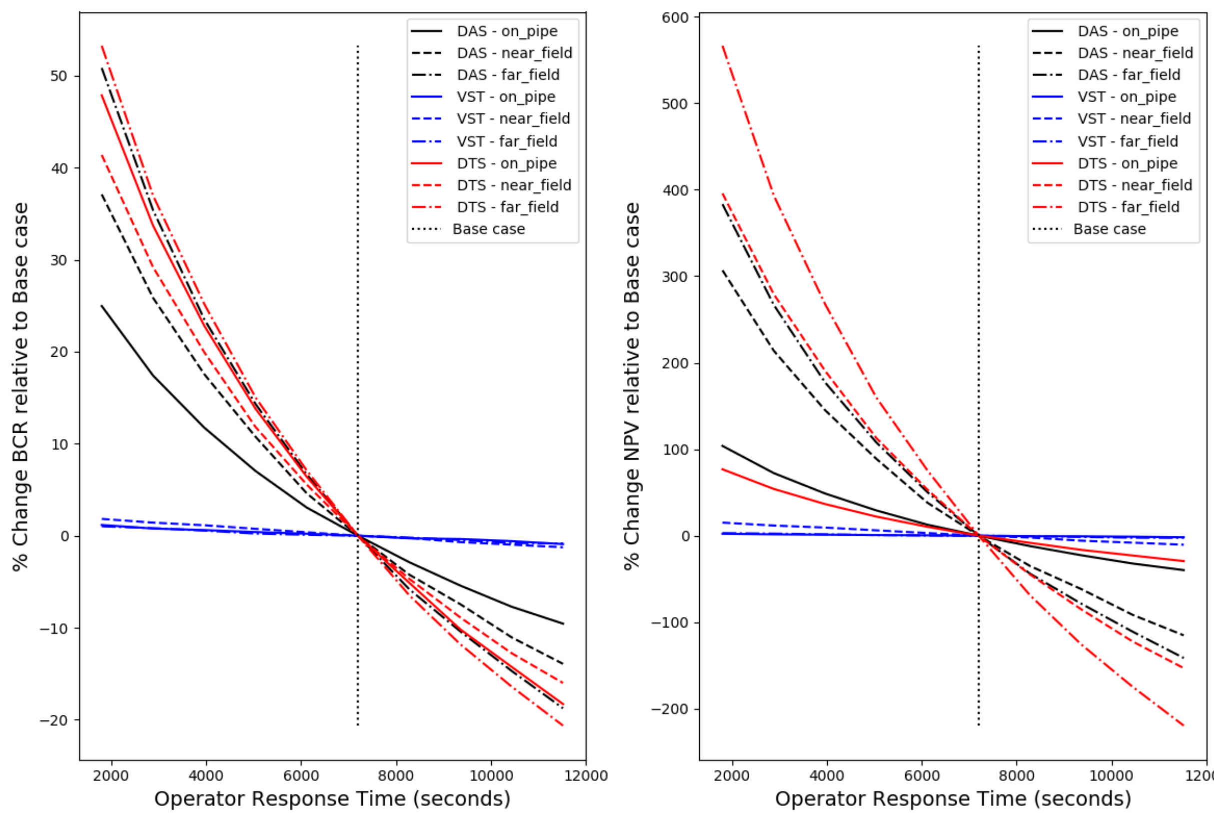

Figure A.5.1 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Operator Response Time for Each of the Preferred Deployment Configurations

For ELD technologies with relatively rapid response times (i.e. DAS and DTS), increasing the operator response time leads to decreasing BCR values and NPVs. By comparison, for ELD technologies with longer response times (i.e. VST), the resulting BCR values and NPVs, while still negatively correlated with operator response time, are far less dependent on variations in operator response time. In general, if the operator response time dominates the total response time (i.e. the operator response time is significantly larger than the ELD response time), then the resulting BCR and NPV values will be more sensitive to modest changes in the operator response time.

A 50% increase in the operator response time (relative to the base case) corresponds to a less than 1% decrease in the resulting BRC values for VST, an 9 to 16% decrease in the resulting BRC values for DAS and a 14 to 18% decrease in the resulting BRC values for DTS. By comparison, a 50% decrease in the operator response time corresponds to a less than 1% increase in the resulting BCR values for VST, a 13 to 26% increase in the resulting BCR values for DAS and a 22 to 28% in the resulting BCR values for DTS. These findings suggest that, depending on the chosen ELD technology and depending on the required degree of accuracy, additional effort to better characterize the operator response time may be warranted. A fixed operator response time was used in the current analysis for ease of demonstration; however, a more detailed analysis might consider a range of possible operator response times, or might chose to treat operator response time as a random variable (i.e. similar to the orifice size, operating pressure and baseline release volume variables).

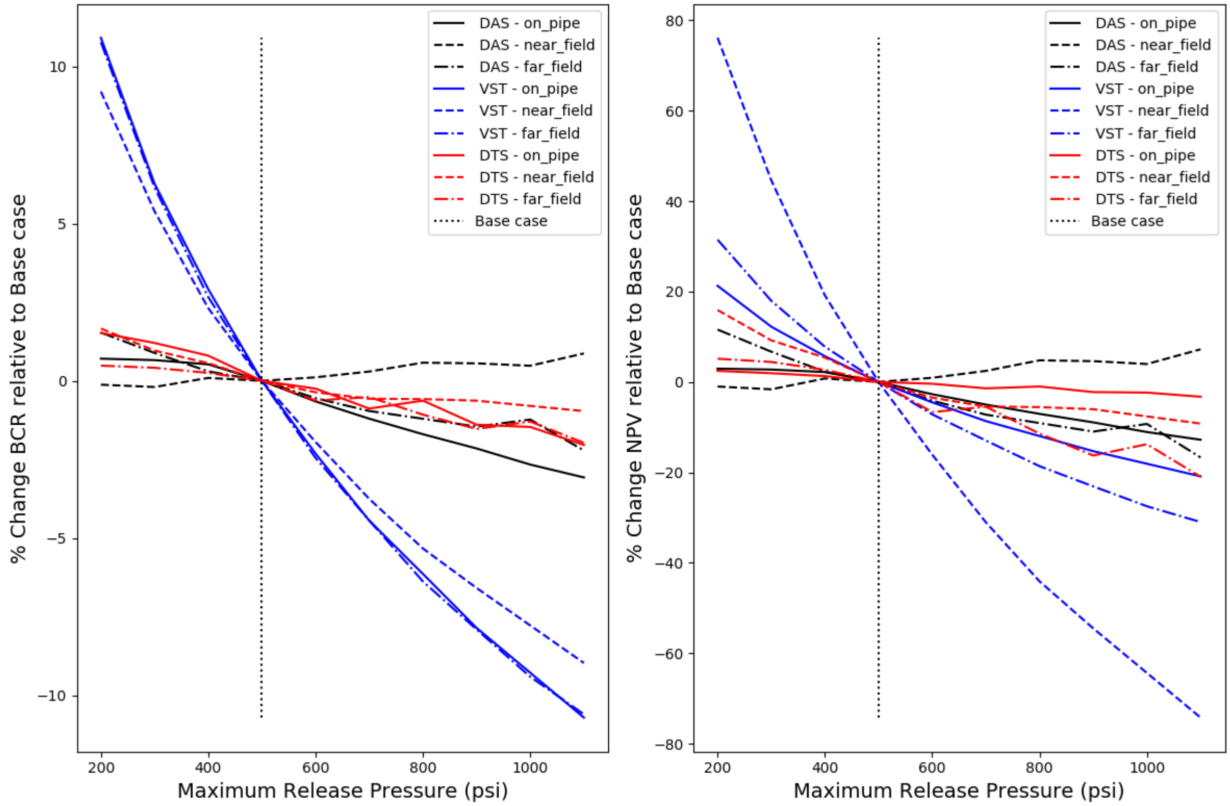

Figure A.5.2 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Maximum Release Pressure for Each of the Preferred Deployment Configurations

For ELD systems with very low detection thresholds (i.e. VST), increasing the maximum operating pressure leads to lower BCR values and NPVs. By comparison, for ELD systems with moderate detection thresholds (i.e. DAS and DTS), increasing the maximum operating pressure does not significantly change the BCR and NPV values. This is because higher release pressures are associated with higher flow rate releases, which are more likely to exceed the detection thresholds of ELD systems, thereby increasing detection rates and improving overall performance. However, detected releases with larger flow rates lead to higher release volumes compared to detected releases with lower flow rates (assuming a fixed overall response time). Therefore, higher operating pressures only benefit ELD systems if the resulting increase in the frequency of detection outweighs the resulting overall increase in release volume of detected releases.

A 50% increase in the maximum release pressure (relative to the base case) corresponds to a 5 to 6% decrease in the resulting BRC values for VST and a less than 1% decrease in the resulting BRC values for DAS and DTS. By comparison, a 50% decrease in the maximum release pressure corresponds to an 8 to 9% increase in the resulting BCR values for VST, and a less than 1% increase in the resulting BCR values for DAS and DTS. These findings suggest that, depending on the chosen ELD technology and depending on the required degree of accuracy, additional effort to better characterize the maximum release pressure may be warranted.

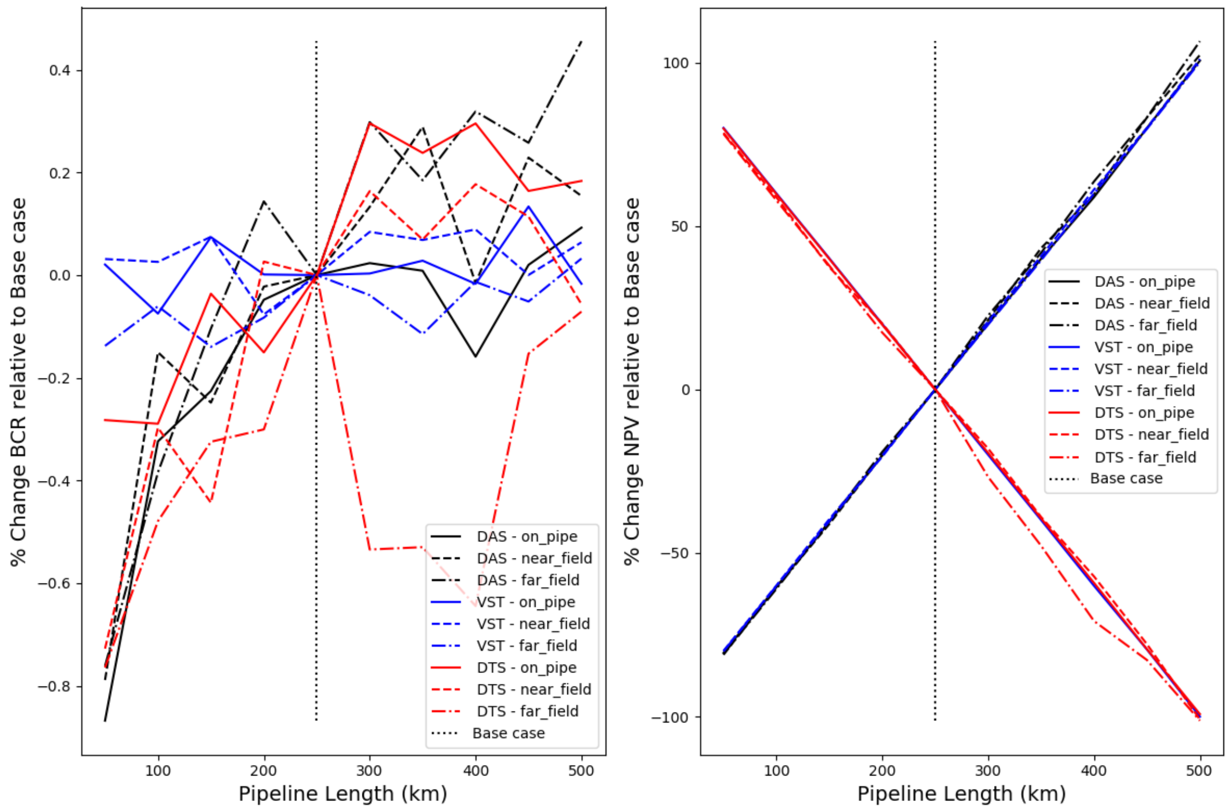

Figure A.5.3 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Pipeline Length for Each of the Preferred Deployment Configurations

BCR is independent of pipeline length, regardless of the ELD technology or deployment configuration.[18] This is because the *PVC* and *PVB* values (i.e. costs and benefits) increase or decrease proportionately with pipeline length. This is also why BCR is a useful metric for evaluating the scalability of different alternatives when a fixed deployment length is not known. For deployment configurations with BCR values that exceed unity, NPV increases proportionally with increasing pipeline length. In comparison, for deployment configurations with BCR values that are less than unity, NPV decreases proportionally with increasing pipeline length. Specifically, alternatives with BCR values that are larger than unity become increasingly profitable with longer deployment lengths.

[18] The observed small fluctuations in BCR values are a result of random model noise and are only visible because of the scale of the y-axis on the BCR plot.

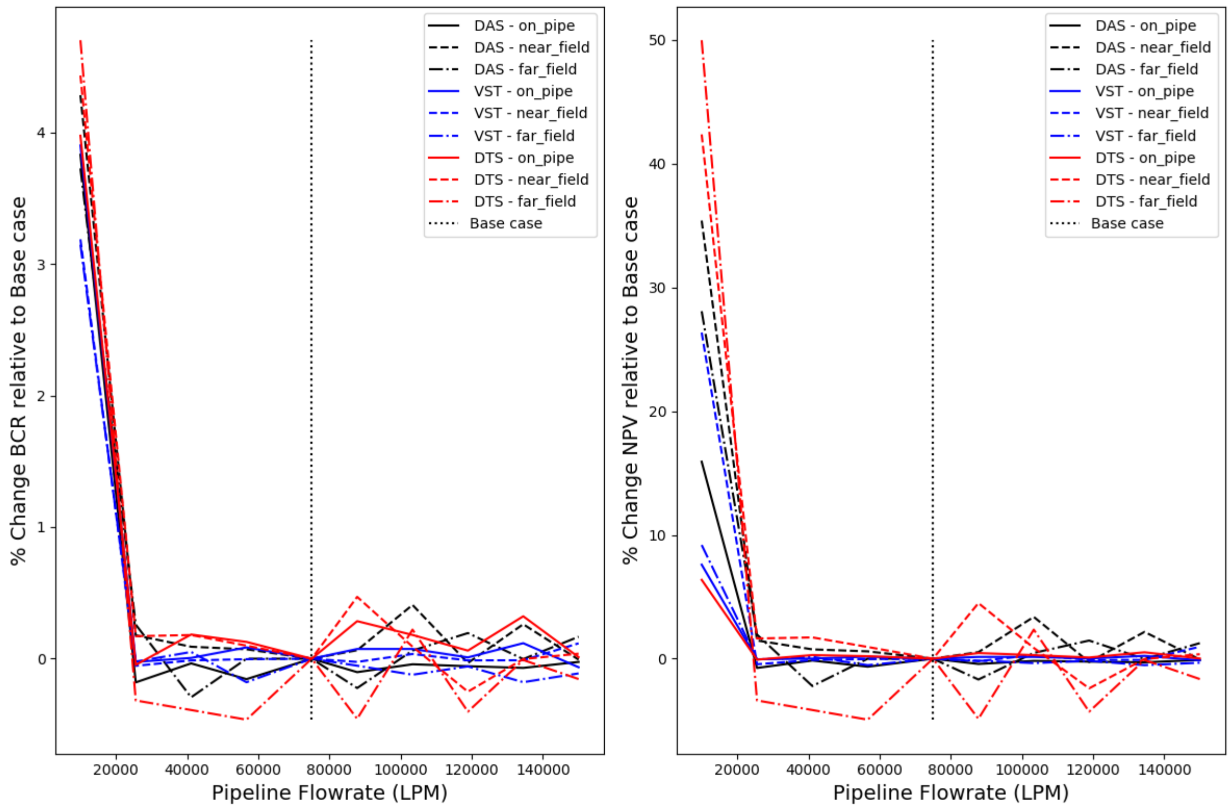

Figure A.5.4 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Pipeline Flow Rate for Each of the Preferred Deployment Configurations

BCR values and NPVs decrease with increasing pipeline flow rate up to a pipeline flow rate of about 7,500 GPM (28,391 LPM) for all ELD technologies and deployment configurations. This is a result of the application of the break release rate threshold, which is used along with the break orifice size threshold to categorize releases as either breaks or leaks (refer to Section A.4.2.2). In essence, a release is categorized as a break if its flow rate exceeds a certain percentage of the pipeline flow rate or if the orifice dimensions exceed a certain size. Higher pipeline flow rates therefore lead to a larger number of relatively high flow rate leaks, thereby increasing the reduced release volume and decreasing the expected reduction in release volume relative to the baseline release volume. However, beyond a certain pipeline flow rate, release categorization is dominated by the orifice size threshold, and the BCR values and NPVs become relatively insensitive to the pipeline flow rate.

These findings suggest that, compared to other model parameters, pipeline flow rate does not affect the output significantly, especially if the pipeline flow rate is above 7,500 GPM. Therefore, pipeline flow rate did not warrant additional consideration.

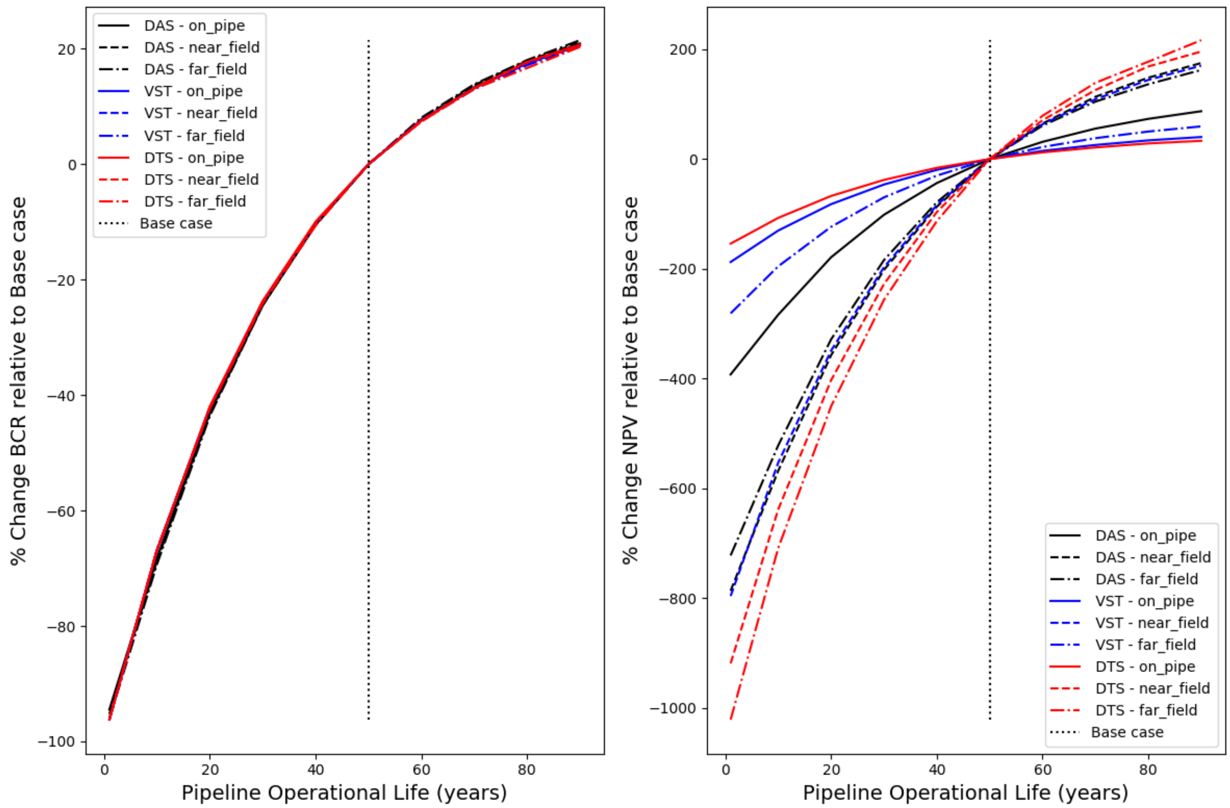

Figure A.5.5 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Pipeline Operating Life for Each of the Preferred Deployment Configurations

BCR values and NPVs increase with pipeline operational life. This is because the significant upfront costs associated with ELD procurement and installation are fixed and independent of pipeline operating life, whereas the expected benefits increase with increasing operating life. The shape of the resulting BCR curves are a function of the adopted discount rate, whereas the shape of the resulting NPV curves are a function of the discount rate and the base case NPV's proximity to zero. All ELD technologies and deployment configurations are evaluated using the same nominal discount rate. This explains why all the BCR values effectively collapse into a single curve.

A 50% increase in the pipeline operational life (relative to the base case) corresponds to a 16% increase in the resulting BRC values for VST, DAS and DTS. By comparison, a 50% decrease in the pipeline operational life corresponds to a 35% decrease in the resulting BCR values for VST, DAS and DTS. These findings suggest that additional effort to better characterize and predict the expected operational life of the pipeline (and, equivalently, the expected operational life of the ELD equipment) is likely warranted. Alternatively, if the nominal pipeline operational life is already believed to be adequately characterized, it might be reasonable to produce an uncertainty interval based on a range of possible or likely pipeline operational life values.

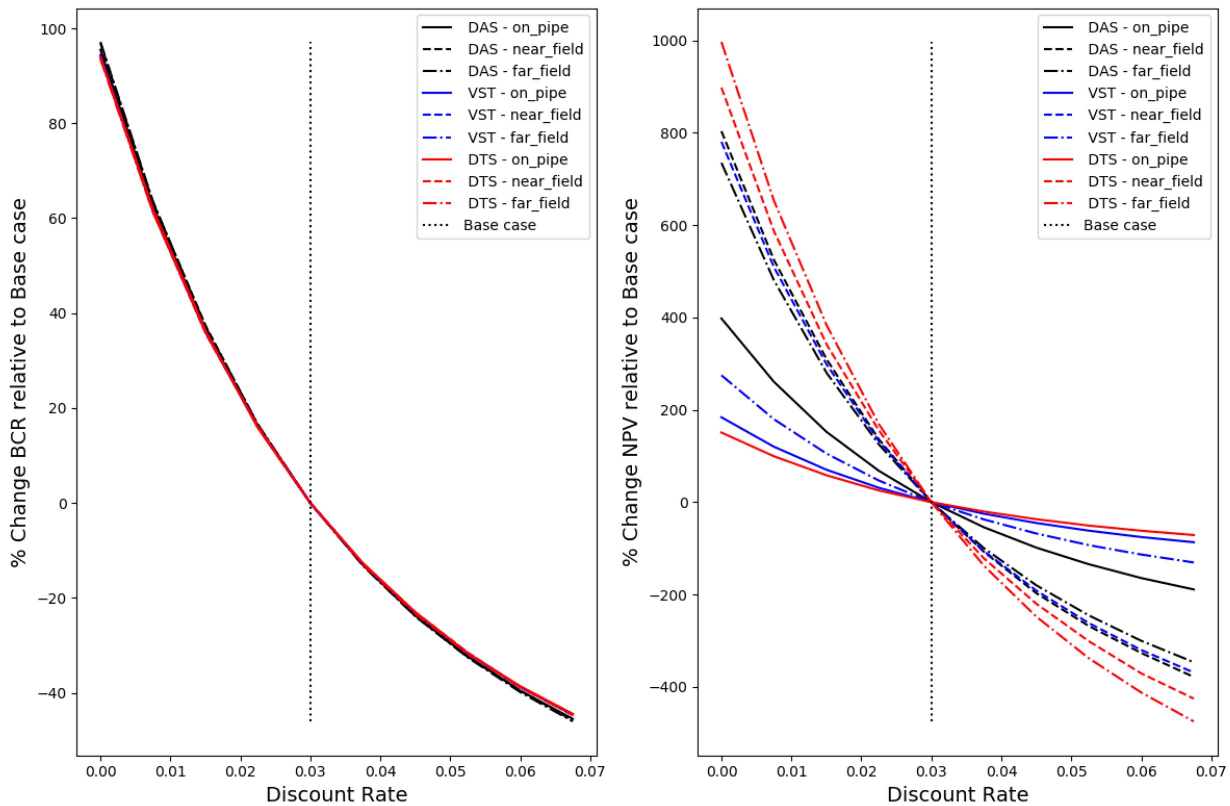

Figure A.5.6 Percent Change in BCR and NPV Relative to the Baseline Value as a Function of Discount Rate for Each of the Preferred Deployment Configurations

BCR values and NPVs decrease with increasing discount rates. This is because the benefits are more evenly distributed through time and, therefore, are more strongly affected by discounting, whereas the costs are assumed to be more concentrated early in time (due to the significant upfront procurement and installation costs) and, therefore, are less affected by discounting. Accordingly, higher discount rates disproportionately reduce the benefits, thereby leading to lower BCR values and NPVs. The shape of the resulting BCR curves are independent of the ELD technology and deployment configurations, whereas the shape of the resulting NPV curves depend heavily on the base case NPV's proximity to zero.

A 50% increase in the discount rate (relative to the base case) corresponds to a 23 to 24% decrease in the resulting BRC values for VST, DAS and DTS. By comparison, a 50% decrease in the discount rate corresponds to a to a 36 to 37% increase in the resulting BRC values for VST, DAS and DTS. These findings suggest that additional effort to better characterize the discount rate is likely warranted. Alternatively, if the nominal discount rate is already believed to be adequately characterized, it might be reasonable to produce an uncertainty interval based on a range of possible or likely discount rates.

A.5.3.2 Scenario Analysis

The scenario analysis described in Section A.5.2.4.2 was performed and Table A.5.3 lists the NPVs and BCR values corresponding to the nine deployment configurations for the two location types considered: HCAs and non-HCAs. The NPVs are shown graphically in Figure A.5.7 and the BCR values are shown graphically in Figure A.5.8 .

Deployment Configuration	Location Type	NPV (Million USD)	BCR
DAS – On Pipe	Non-HCA	-11.9	0.44
DAS – On Pipe	HCA	6.7	1.32
DAS – Near Field	Non-HCA	-10.1	0.38
DAS – Near Field	HCA	2.3	1.14
DAS – Far Field	Non-HCA	-7.0	0.38
DAS – Far Field	HCA	1.8	1.16
VST – On Pipe	Non-HCA	-17.3	0.22
VST – On Pipe	HCA	-7.5	0.66
VST – Near Field	Non-HCA	-9.9	0.38
VST – Near Field	HCA	2.2	1.14
VST – Far Field	Non-HCA	-4.7	0.51
VST – Far Field	HCA	5.0	1.52
DTS – On Pipe	Non-HCA	-17.3	0.21
DTS – On Pipe	HCA	-8.3	0.62
DTS – Near Field	Non-HCA	-11.7	0.30
DTS – Near Field	HCA	-1.6	0.91
DTS – Far Field	Non-HCA	-8.2	0.30
DTS – Far Field	HCA	-1.1	0.91

Table A.5.3 NPV and BCR as a Function of Different Deployment Configurations, and Location Types

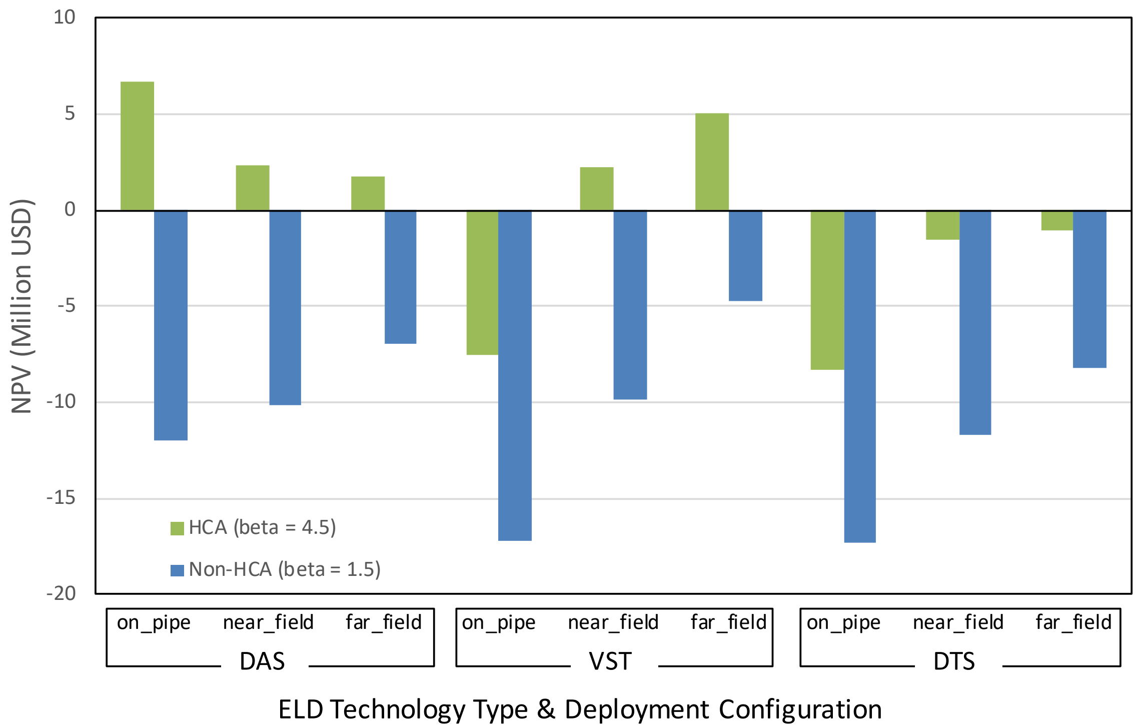

Figure A.5.7 NPV as a Function of Different Deployment Configurations, and Location Types

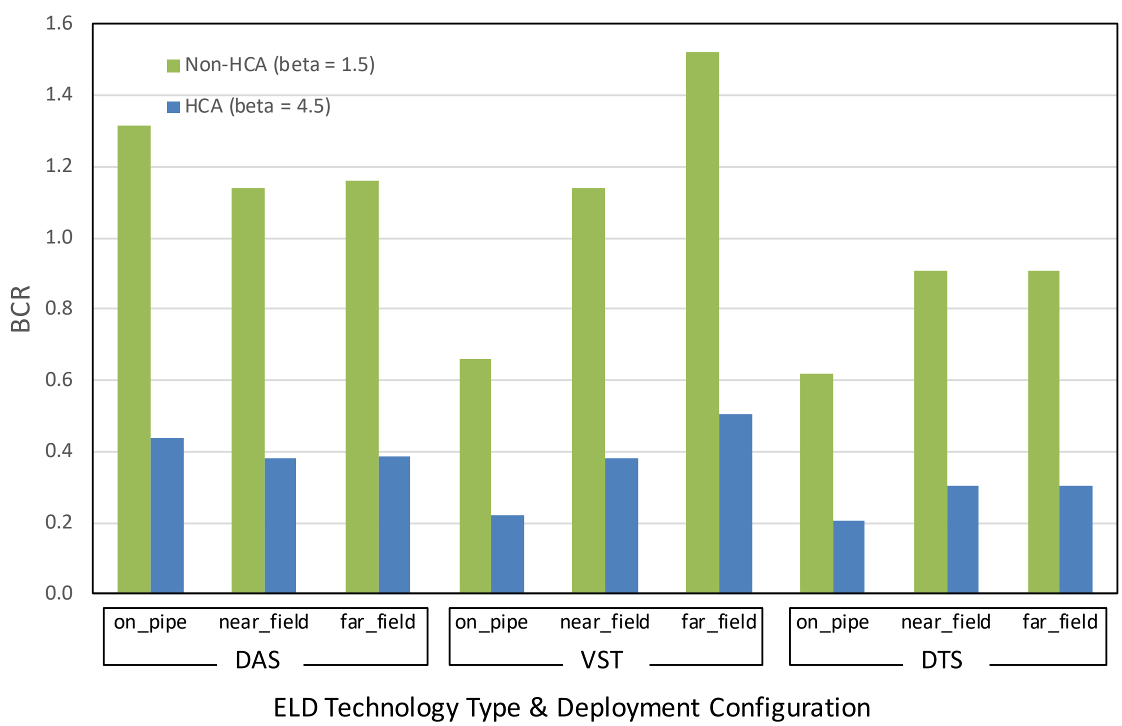

Figure A.5.8 BCR as a Function of Different Deployment Configurations, and Location Types

The alternatives associated with non-HCAs all have negative NPVs and sub-unity BCR values. Accordingly, none of the candidate ELD technologies would be recommended for deployment in non-HCA locations on the demonstration pipeline. By comparison, several deployment configurations have positive NPVs and BCR values greater than unity if deployed in HCA locations (i.e. DAS – On Pipe, DAS – Near Field, DAS – Far Field, VST – Near Field and VST – Far Field). Under the stated assumptions, these deployment configurations would be expected to be cost effective over the course of their anticipated life span and would, therefore, potentially be recommended for deployment.

In addition, it is noted that, for alternatives with negative NPVs or sub-unity BCR values, implementation may still be deemed justifiable on the basis that actions that achieve enhanced safety and/or environmental protection are justifiable provided that implementation costs do not grossly exceed the expected benefits.[19]

The CBA Framework provides the following guidance in selecting a preferred CBA alternative if multiple alternatives are shown to be cost-effective (refer to Section 5.3.2 in the CBA Framework):

> *If multiple alternatives are shown to be cost effective, NPV is usually the most informative and, therefore, the recommended cost-benefit measure for identifying a preferred alternative because it measures the true contribution of a project to economic welfare.*

However, NPV is not always the most appropriate CBA evaluation metric. In certain cases, other evaluation metrics might be required in place of, or in combination with, NPV. These scenarios are explored in the following paragraphs.

In cases where the highest NPV is not significantly different from the next highest NPV, the best alternative is not necessarily the one with the highest NPV. This is especially true if the single variable test (refer to Section A.5.3.1) identifies one or more input parameters with: 1) a high degree of influence on NPV, and 2) a high degree of uncertainty. In these scenarios, it may be necessary to consider the BCR score in addition to the NPV score (refer to Section 5.3.2 in the CBA Framework). Alternatives with higher BCR values have a more substantial buffer separating benefits from costs and are, therefore, more likely to remain cost effective despite potential uncertainty in the input parameters. Depending on the degree of uncertainty associated with the suspect input parameters and on the degree of similarity between the highest NPVs, it may be appropriate to distinguish between two or more alternatives with similar NPVs based on their respective BCR values. The highest NPV from Table A.5.3 exceeds the next highest value by a comfortable margin (25%). For this reason, BCR is not required as a complementary evaluation metric on the demonstration pipeline.

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[19] This effectively being an application of the principal of As Low as Reasonably Practicable (ALARP) as it pertains to safety risk management (16).

In cases where operators choose to base the total mileage over which the ELD system is to be deployed (i.e. ELD deployment mileage) on a fixed budget rather than a fixed length (i.e. the total ELD deployment mileage will be as large as the budget allows), the best alternative is not necessarily the one with the highest NPV. In the demonstration exercise, a fixed mileage of 155 miles was selected. This means that alternatives with a lower per-mile cost have smaller budgets than alternatives with higher per-mile costs. However, if instead the budget was fixed, alternatives with a lower per-mile cost would have longer ELD deployment mileages than alternatives with higher per-mile costs. Accordingly, the NPVs shown in Figure A.5.7 may not correctly identify the best possible option. The best way to evaluate alternatives with fixed, identical budgets and variable deployment lengths is to instead consider the BCR. If ELD deployment on the demonstration pipeline was based on a fixed budget rather than a fixed length, the "VST – Far Field" deployment configuration in an HCA would be the preferred alternative.

In cases where pipeline operators might have specific ELD requirements, such as a minimum detectable release rate, the operator may wish to choose the technology with a positive NPV that is capable of detecting the smallest possible leak, regardless of whether it has the highest NPV. In this example, "VST – Far Field" would be selected over "DAS – On Pipe", despite it having a lower NPV.

The preferred deployment configuration is the "DAS – On Pipe" deployment configuration. It was shown that the demonstration pipeline does not apply to any of the cases discussed above. Therefore, selection of the preferred deployment configuration was based on the alternative with the highest NPV. BCR was not needed in determining the preferred alternative; however, it was useful in assessing the degree of input parameter sensitivity (refer to Section A.5.3.1).

It was assumed that the demonstration pipeline traverses a finite length of HCA locations; therefore, a fixed deployment length of 155 miles was selected. However, for expanded ELD deployment on other sections of the demonstration pipeline, including on non-HCA sections, it may be more appropriate to fix the ELD budget rather than the deployment length. In these cases, the "VST – Far Field" deployment configuration would be the preferred alternative because it has a higher BCR score and, therefore, is expected to be more scalable when deployment length is not constrained.

These findings are primarily intended to demonstrate the CBA process as described in the CBA Framework. The final ELD technology rankings (based on the calculated NPVs and BCR values) should not be interpreted to suggest that one ELD technology type is superior to that of the other. Rather, the results should be interpreted to suggest that, given the information available, and with reference to the specific conditions that pertain to the demonstration pipeline, one ELD technology, installed in the described preferred deployment configuration, is indicated as being more cost effective under the stated assumptions.

A.6. SUMMARY

A CBA was performed to evaluate and compare three hypothetical ELD systems for possible implementation on a hypothetical pipeline (i.e. the "demonstration pipeline"). The purpose of this demonstration exercise is to demonstrate and illustrate the application of the CBA Framework developed in this project.

The selection of the demonstration pipeline was guided by two primary considerations: to provide a clear and practical demonstration of selected key aspects of the CBA Framework, and to make the findings of the demonstration exercise as broadly applicable as possible. To this end, the demonstration pipeline is assumed to:

- Be a new-construction project (as opposed to a legacy pipeline);
- Transport crude oil;
- Reside below ground;
- Be equipped with a CPM system;
- Have a nominal operational life cycle of 50 years;
- Require ELD deployment on a 155-mile section;
- Have a nominal operator response time of 2 hours;
- Experience unintentional product releases ranging in pressure from 100 to 500 psi; and
- Traverse a soil environment characterized by sandy soil with minimal amounts of silt and clay.

The three following candidate, hypothetical ELD technologies were identified for evaluation in the demonstration exercise:

- DAS;
- VST; and
- DTS

The candidate ELD technologies are representative of commercial ELD systems that are typically installed on existing transmission pipelines. The listed technologies are well established, and many pipeline operating companies are reasonably familiar with them. Further, they are believed to adequately capture the possible range of performance capabilities of existing commercial systems in terms of response time and detection threshold.

A number of potential deployment configurations were identified for each of the candidate ELD technologies. Scores based on the relative deployability and relative performance were then assigned to each of the identified deployment configurations. It was decided to carry forward the three deployment configurations with the highest overall scores for each of the candidate ELD technology vendors following a process that is consistent with the guidance provided in the CBA Framework. These deployment configurations, referred to as the preferred deployment configurations, are listed as follows:

- DAS - On Pipe
- VST - On Pipe
- DTS- On Pipe
- DAS - Near Field
- VST - Near Field
- DTS - Near Field
- DAS - Far Field
- VST - Far Field
- DTS - Far Field

The "On Pipe" configurations are located on the pipeline's outer surface at the 12 o'clock position. The "Near Field" configurations are located along the bottom of the trench in the so-called shadow region of the pipeline (i.e. the area defined as being within the shadow that would be cast on the trench floor if a light were shone on the pipe from directly above). Finally the "Far Field" configurations are located at the intersection of the trench floor and the trench wall. The DAS and DTS sensors are assumed to be deployed in conduit, whereas the VST sensor is not. The preferred deployment configurations were carried forward throughout the remainder of the demonstration exercise and were a key component of the sensitivity analysis.

Consistent with the guidance provided in the CBA Framework, costs associated with each of the preferred deployment configurations were arranged into two main categories: initial costs and recurring costs. Initial costs (i.e. procurement and installation costs) and recurring costs (i.e. operation and maintenance costs) for each of the preferred deployment configurations were determined through a combination of TAP guidance, discussions with representative ELD technology vendors and available public domain literature.

The overall benefit associated with each of the preferred deployment configurations was assumed to comprise predominantly of environmental protection enhancements. More specifically, it was assumed that the overall benefit is based wholly on the expected reduction in release volume that would result from ELD implementation. This is because the demonstration pipeline is assumed to transport crude oil. Given the relatively low life safety risks associated with the transport of crude oil, especially compared to natural gas, life safety benefits are assumed not to be significant and are therefore not considered in the benefit characterization exercise. Further, the candidate ELD systems are assumed not to have any encroachment detection capabilities. Therefore, break prevention is assumed to be minimal and, accordingly, so is the potential to reduce injuries from overpressure.

The environmental protection benefits were calculated using a hybrid approach that is consistent with the guidance provided in the CBA Framework. This approach was selected because the demonstration pipeline is a new-construction pipeline and, therefore, it was assumed that there is no ILI data from which to leverage a full probabilistic analysis. While a deterministic analysis was possible, it was assumed not to provide the required degree of accuracy and granularity, and it was, therefore, not pursued. In the adopted hybrid approach, the baseline release volume, the reduced release volume and the failure rate were calculated by averaging the results from repeated deterministic calculations over a large number of random realizations from the baseline release volume distribution and other random variables.

The costs and monetized benefits were temporally distributed throughout the pipeline's operational life span and converted into present-day equivalent values using a nominal social discount rate of 3%. A single variable test was then carried out to identify input parameters with the greatest impact on the adopted evaluation metrics (i.e. NPV and BCR). These parameters were flagged, and additional consideration was given in order to minimize the associated uncertainty associated with them to the extent possible. Then, NPVs and BCR values were calculated for each of the preferred deployment configurations in both HCA and non-HCA locations. It was shown that the candidate ELD systems, when deployed in HCA locations, are generally cost effective, whereas they are not cost effective when deployed in non-HCA locations.

Because there was found to be sufficient separation between the highest and second highest NPVs (25%), and also because ELD is assumed to be deployed along a fixed length of 155 miles rather than over a fixed budget, the selection of a preferred alternative was based on NPV alone. The "DAS – On Pipe" deployment configuration had the highest NPV score (among cost effective alternatives) and was, therefore, selected as the preferred alternative. However, for expanded ELD deployment on other sections of the demonstration pipeline, including on non-HCA sections, it may be more appropriate to fix the ELD budget rather than the deployment length. In these cases, the "VST – Far Field" deployment configuration would be the preferred alternative because it has a higher BCR score and, therefore, is expected to be more scalable when deployment length is not constrained.

The results presented in this demonstration are primarily intended to demonstrate the CBA process as described in the CBA Framework. The final ELD technology rankings (based on the calculated NPVs and BCR values) should not be interpreted to suggest that one ELD technology type is superior to that of the other. Rather, the results should be interpreted to suggest that, given the information available, and with reference to the specific conditions that pertain to the demonstration pipeline, one ELD technology, installed in the described preferred deployment configuration, is indicated as being more cost effective under the stated assumptions.

A.7. REFERENCES

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