A RISK MANAGEMENT TOOL FOR ESTABLISHING BUDGET PRIORITIES

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ABSTRACT

Pipeline operators have obligations to their owners or stockholders to protect their assets and to their employees and the public to minimize the potential for injury-producing or property-loss accidents. Pipeline risk management programs are generally instituted to meet these obligations. One technique that has proven its value in pipeline risk management is "prioritizing" based on a ranking model. By means of prioritizing, a pipeline operator can expect to enhance or optimize the effectiveness of a maintenance program in the sense that the areas of potential risk will be identified and ranked in the order, which achieves the most safety for the least cost. Such models typically contain a "feedback" feature, which allows reranking in response to risk reduction activities such as removal of anomalies, replacement of questionable components, or implementation of improved procedures. "What if" scenarios can be examined for planning and budgeting purposes using this feature. Ranking models can be linked to the operator's GIS system and/or system parameters database. The generic concepts of ranking models are discussed herein.

BACKGROUND

A fair number of ranking models for prioritizing pipeline maintenance exist. Some have been created by individual operators [1-7] while others have been formulated through industry groups [8,9] or by contractors serving the industry [10,11]. The concepts embodied in many of these will be addressed. First, I would like to point out that ranking for maintenance purposes is a tool for managing risk. It does not provide a true risk assessment, but it can be the basis for reducing risk and/or efficiently allocating maintenance expenditures.

For an operating system risk arises from the probability that a loss-producing accident can occur. The risk associated with such an accident can be calculated as the product of two quantities: the probability that a failure of the system can occur and the consequences that can arise as a result. Well-known techniques such as fault-tree analyses may be used to calculate probabilities of failure provided that failure rates are known. Consequences can be assessed by means of complex computer programs, which are capable of assessing various failure scenarios. Probabilistic risk assessments of this type are made for chemical and refining processes, for nuclear power plants, and for aerospace systems. Such assessments are not done routinely for pipelines for two reasons. First, the accident-producing factors for pipelines vary so widely that reliable failure rate data are virtually nonexistent. Second, to a large extent pipeline safety improvements can be effected without knowing the true risk associated with a given pipeline operation. Therefore, the industry has tended to rely on ranking models to augment their risk management activities and to prioritize maintenance. The concepts involved in these relatively simple techniques are explained below.

BASIC RANKING CONCEPTS

Most ranking models emulate probabilistic risk assessment by calculating risk as a "relative" number. The latter is the product of "pseudo-probabilities" of failure and "relative" consequence scenarios. As in probabilistic risk assessment, the perceived causes of failure are postulated. In the absence of reliable failure rates, however, the analyst creates equations based upon system and operating parameters, which are known to influence the likelihood of failure for a given section of a pipeline.

Instead of calculating realistic outcomes of various accident scenarios to evaluate true consequences, the creators of ranking models usually construct simple equations, which embody relative outcomes of accidents based on factors such as population density, product release size, and loss of service for a given section of a pipeline. The section of pipeline is then given a "relative risk" or ranking number, which is the product of its pseudo-probability of failure and its relative consequence of failure. Sections of a pipeline or pipelines within a system may then be ranked according to relative risk. Those having the highest relative risk can be allotted the most attention with respect to maintenance or remedial measures.

FAILURE PROBABILITIES

Causes of Failure

Ranking models for pipeline maintenance can involve several causes of failure. Almost always they address outside force (including damage by excavating equipment), external corrosion, and manufacturing or construction defects. Other causes that may be considered include soil instability, internal corrosion, equipment failure, and operator error.

Construction of Equations by Cause

Equations for the probabilities of failure by cause are constructed from factors perceived to influence the occurrence of a failure. For example, a typical equation for the probability of failure from outside force might consider the following.

> Pipe geometry (the thinner the pipe or the smaller its diameter, the more easily it is damaged)
>
> Material (strength and toughness contribute to damage resistance)

Depth of Cover (the deeper the pipe, the less likely it will be encroached upon)
Exposure (the higher the level of construction activity the greater the chance a pipeline will be damaged)

Damage prevention (the probability of damage is reduced by responses to one-call systems, active patrolling, public education, communications with land owners, robust right-of-way maintenance and marking programs).

Hence the typical equation for the probability of failure from outside force, P_{of}, might look something like this. Bear in mind that these are only examples. Also, please refer to Figure 1 to see the details of each equation.

$$P_{of} = \begin{pmatrix}\text{Pipe} \\ \text{Geometry}\end{pmatrix}\begin{pmatrix}\text{Material} \\ \text{Factor}\end{pmatrix}\begin{pmatrix}\text{Depth of} \\ \text{Cover}\end{pmatrix}(\text{Exposure})\begin{pmatrix}\text{Damage} \\ \text{Prevention}\end{pmatrix} \tag{1}$$

where

Pipe Geometry is a function of $1/t^2 + 12/D$, t is wall thickness; D is diameter both in inches.

Material Factor is $100{,}000/\text{SMYS} + \left(10/\sqrt{\text{CVN}}\right) + C_1$, SMYS is specified minimum yield strength in psi; CVN is the Charpy V-notch upper shelf energy in ft-lb, and C_1 is zero if the pipe is never exposed to a temperature below its ductile-to-brittle transition temperature, one if the pipe is sometimes exposed to temperatures up to 60°F below its transition temperature, and ten if the pipe is frequently exposed to temperatures of 60°F or more below its transition temperature or if its transition temperature is unknown.

Depth of Cover is $(3/d_c)^{1.5}$, d_c is the depth of cover in feet.

Exposure is $(1+0.1C_2+C_3+100C_4)$, C_2 is the number of foreign line crossings, road crossings, and river crossings in the segment; C_3 is a number ranging from 1 to 5 depending on the perceived construction activity; and C_4 is the number of outside force incidents per mile per year on the segment.

Damage Prevention is $(1+5C_5+5C_6+C_7+C_8)$, C_5 ranges from 0 to 1 and represents the one-call response, i.e., 1 for locating and marking the pipeline, 0.5 for locating, marking and providing an on-site representative, and 0.1 if the operator exposes the line for the excavating contractor; C_6 ranges from 0 to 1 and represents patrolling, i.e., 1.0 for bi-weekly overflights, 0.5 for 2 overflights per week, 0.1 for 3 or more overflights per week; C_7 ranges from 0 to 1 and represents communication with land-owners, i.e., 1 for none, 0.8 for periodic contacts by mail, 0.5 for periodic face-to-face meetings; C_8 represents right-of-way maintenance and marking and ranges from 0.5 to 1, i.e., 0.5 for robust program, 1.0 for normal program.

Factors which one would expect to affect the probability of failure from corrosion would be the thickness of the pipe (the thicker it is, the longer it takes for corrosion to penetrate the wall thickness) the presence and effectiveness of a cathodic protection system, the presence and effectiveness of an anti-corrosion coating, the effect of the soil on the coating and the ability to cathodically protect the pipe, and the operating experience associated with a particular segment of pipe including its leak history.

Accordingly, the equation for the probability of failure from corrosion P_{cor}, might look like this.

$$P_{cor} = \left(\frac{1}{t}\right)\begin{pmatrix}\text{Cathodic} \\ \text{Protection}\end{pmatrix}(\text{Coating})\begin{pmatrix}\text{Soil} \\ \text{Factor}\end{pmatrix}\begin{pmatrix}\text{Experience} \\ \text{Factor}\end{pmatrix} \quad (2)$$

where

t is the wall thickness of the pipe, inches.

Cathodic Protection is $8T_1 + \frac{E_{cp}}{3} T2, T1$ represents the time in years that the pipeline was buried without cathodic protection being applied and T_2 represents the time in years that the pipeline has been subjected to cathodic protection. The coefficient, E_{cp}, is based upon the perceived effectiveness of the cathodic protection. E_{cp} could be 1.0 for an adequately protected, coated pipeline, but it could range as high as 4 for a poorly protected, bare pipeline.

Coating (CT) is usually a number ranging between 1 and 20 where 1 represents the best coating available and 20 represents bare pipe. Companies typically represent fusion-bonded epoxy coating as 1 or 1.5, coal tar enamel as 1, 1.5 or 2, and single-layer polyethylene tapes as 8.

Soil Factor (SF) might range from 5 to 10 where 5 represents a benign soil which neither damages coating nor shields the pipe from cathodic protection and where 10 represents a coating-damaging soil and/or one which tends to shield the pipe from cathodic protection.

Experience Factor should include a constant of 1.0 to prevent it from being zero and the number of corrosion leaks per mile per year, C_9 (multiplied by 50). It may also include observations of the pipe or coating condition based on bell-hole inspections, cathodic protection surveys, and/or cathodic current consumption.

The probability of failure from manufacturing or construction defects is strongly influenced by the operating hoop stress level and its relationship to the preservice hydrostatic test level. In addition, the age of the pipe material and known material deficiencies may be taken into account. For example, the probability of failure from manufacturing and construction defects, P_{mc}, might be

$$P_{mc} = \left(\frac{\text{MAOP}}{\text{HTP} - \text{MAOP}}\right)\begin{pmatrix}\text{Age} \\ \text{Factor}\end{pmatrix}\begin{pmatrix}\text{Seam} \\ \text{Factor}\end{pmatrix}\begin{pmatrix}\text{Girth Weld} \\ \text{Factor}\end{pmatrix} \quad (3)$$

where

MAOP is the maximum allowable operating pressure.

HTP is the hydrostatic test pressure (mill test pressure may be used if the actual preservice test pressure is unknown).

Age Factor could be as simple as the number of years in service but if the pipeline operator feels that this is too extreme, the effect of years in service could be tempered by adding a constant (e.g., 100).

Seam Factor (C_{10}) is generally taken to be the reciprocal of the longitudinal joint design factor (e.g., 1/0.6 for butt-welded pipe, 1/0.8 for lap-welded pipe).

Girth Weld Factor (C_{11}) can be set at 1 for high-quality shield-metal-arc girth welds; 1.2 for adequate-quality girth welds; and 1.5 for poor-quality girth welds, acetylene welds, or mechanical joints.

CONSEQUENCES

The relative consequences of an incident are usually based on the perceived chances that people will be killed or injured, that property losses will occur, and that loss of the product and loss of service will be costly to the pipeline operator. These outcomes logically would seem to be a function of the population and property exposed, the violence of the incidence (including sudden pressure release as well as possible explosion and fire), the amount of product lost, the effect on other company operations, and the customers or shippers affected. The exposure of population and property value is often simply assumed to be proportional to the "class location" as defined for natural gas pipelines by the ASME B31.8 code and Part 192 of the federal regulations. The violence of an incident can conveniently be expressed in terms of the hoop stress level in the pipe or the pressure and the size of the release (i.e., pinhole leak, small hole, or significant rupture). The probability of ignition can be considered as well as the type of thermal event (i.e., torch fire, deflagration, or detonation). However, the latter two are usually relevant to products such as ethylene or propane and not natural gas. Losses to the company, the customers or the shippers can be considered in terms as simple as the amount of throughput lost, and/or the number of customers disrupted. Lastly, in the case of many liquid petroleum products, damage to the environment may be a significant factor. An example is shown below in which "Q" represents the consequences.

$$Q = \begin{pmatrix}\text{Class}\\ \text{Location}\end{pmatrix}(\text{MAOP})(\text{Diameter})^n\begin{pmatrix}\text{Release}\\ \text{Size}\end{pmatrix}\begin{pmatrix}\text{Throughput}\\ \text{Loss}\end{pmatrix}\begin{pmatrix}\text{Customers}\\ \text{Interrupted}\end{pmatrix}\begin{pmatrix}\text{Environmental}\\ \text{Damage}\end{pmatrix} \qquad \boxed{4}$$

The "class location" factor can be chosen as 1, 2, 3, or 4 corresponding to the defined class location. Alternative formats include using the number of houses in the definitions of class location (10, 46, 100, and an arbitrary number, say 200, for Class 4) or the reciprocal of the design factor for each class location (1/0.72, 1/0.60, 1/0.50, and 1/0.40). The appropriate choice can be ascertained in the type of sensitivity analysis described later herein. MAOP or maximum allowable operating pressure is usually used as a factor, and diameter is used raised to a power. The power "n" may be fractional or one or a number greater than one. Release size is often not used at all for natural gas pipelines because small leaks usually do not pose significant risks. For motor fuels, crude oil, or highly volatile liquids, leaks can be damaging, however, and release size takes on more importance. Throughput loss (C_{12}) and customers interrupted (C_{13}) are highly operator-specific. These terms are usually handled by integers ranging from 1 to 10 based largely upon the operators' judgment. The environmental damage term can also be handled in terms of a range of integers depending on the potential for water pollution or destruction of wildlife.

RELATIVE RISK CALCULATIONS

The calculation of relative risk, R, for ranking pipeline segments can be expressed as follows

$$R = (m_1 P_{of} + m_2 P_{cor} + m_3 P_{mc})\, Q / 1000 \tag{5}$$

P_{of}, P_{cor}, P_{mc} are the probabilities of failure for the causes considered

Q is the consequence number

m_1, m_2, m_3 are coefficients, if needed, to balance the relative effects of the probabilities.

Other options that can be considered are as follows. If an operator wishes to consider the effects of release size, an R_{Leak}, for "leaks" may be calculated and an $R_{Rupture}$ for "ruptures" may be calculated. In these cases the relevant Q values would be based upon the different values of the release-size term, and the "m" coefficients of Equation (5) might by adjusted for release size effects. For example, since a higher percentage of outside force incidents than corrosion incidents are known to occur as ruptures, the release size versions of Equation (5) might look like this:

$$R_{Leak} = (0.75P_{of} + 0.95P_{cor} + 0.80P_{mc})\, Q_{leak} / 1000 \tag{5a}$$

$$R_{Rupture} = (0.25P_{of} + 0.05P_{cor} + 0.20P_{mc})\, Q_{rupture} / 1000 \tag{5b}$$

This level of sophistication is probably not necessary for natural gas pipelines because small leaks usually have no significant consequences.

MITIGATION OF RISK

A pipeline operator may use the foregoing equations to obtain "R" values for any number of pipeline segments. The list of segments ranked by R values provides a rational basis for carrying out a rehabilitation or maintenance program. The model also can provide a means for assessing mitigative measures and for reranking the segments as the measures are applied. For example, for a pipeline exposed to a high risk of failure from outside force, deeper burial (by lowering the line at critical locations), more frequent patrolling, better right-of-way maintenance and marking, more active response to one-calls, and better communication are all options for reducing risk which have values represented in Equation (1). Changes in relative risk in response to any or all of these mitigative measures can be readily calculated.

Another kind of assessment of mitigative action arises in conjunction with in-line inspection and hydrostatic testing. In these cases a risk reduction factor can be applied to the P_{cor} term. These factors are usually of the following form.

$$F_{ILI} = \frac{T_{NOW} - T_{ILI} + 1}{10} \tag{6}$$

$$F_{HRT} = \frac{T_{NOW} - T_{HRT} + 1}{5} \tag{7}$$

where

F_{ILI} is the factor applied to P_{COR} if in-line inspection is carried out followed up by appropriate repairs

F_{HRT} is the factor applied to P_{COR} if a hydrostatic test to at least 1.25xMAOP is applied to the pipeline.

T_{ILI} is the year of the repair response following an in-line inspection

T_{HRT} is the year of the hydrostatic retest

T_{NOW} is the current year.

In effect the credit for these mitigative steps is time-dependent. The credit is substantial immediately. P_{cor} is reduced by 90 percent following the in-line inspection repairs or by 80 percent following a hydrostatic test. In ten years the credit for in-line inspection is gone and in five years the credit for hydrostatic retesting is gone.

EXAMPLES

The equations of the model are summarized in Figure 1, and two pipelines are compared using the model in Table 1. The use of the model is demonstrated by these examples.

DISCUSSION

The ranking model embodied in Equations 1-7 is simple and generic. It could be useful if customized for a given operator. It needs two essential preliminary evaluations, however. First, it needs to be subjected to a rigorous sensitivity analysis. The effect on each of the major terms: P_{of}, P_{cor}, P_{mc}, Q, and R of changes in the input parameters over realistic ranges should be made to assure that all terms and coefficients lead to reasonable answers. Second, a reality check is needed in which the model's output is compared to historical experience. In this manner a pipeline operator establishes confidence in the model and is more likely to consider it a useful decision-making tool. Finally, the following advice should be kept in mind. Accidents can occur in pipeline systems in spite of the availability of a ranking model because no model can be expected to perfectly describe the performance of a system and because the values used in model, although they may be the best available, may not adequately describe the physical reality. Other reasons why a risk assessment might not prevent an accident could be that the user does not or cannot respond fast enough to the list of needed maintenance, and that a ranking model has no means for assessing when all of the essential responses have been carried out. Nevertheless, with a ranking model the chances are very good that a pipeline operator can prioritize correctly and thus spend the available maintenance dollars wisely.

Table 1. Two Pipelines Compared on the Basis of the Generic Ranking Model

Parameter	Symbol	Value for Line 1	Value for Line 1
Diameter, inches	D	12.75	30
Wall thickness, inches	t	0.250	0.375
Yield Strength, psi	SMYS	42,000	52,000
Charpy V-notch upper-shelf energy, ft-lb	CVN	25	25
Transition Temperature Factor	C_1	1	1
Depth of Cover, feet	d_c	3	3
Number of Crossings	C_2	2	2
Construction Activity Factor	C_3	4	2
Outside Force Incidents/Mi/Yr	C_4	0.02	0
One-Call Response Factor	C_5	0.5	0.5
Patrolling Frequency Factor	C_6	1	1
Communications Factor	C_7	0.8	0.8
R.O.W. Maintenance/Marking Factor	C_8	1	1
Years in Service without CP	T_1	0	10
Years in Service with CP	T_2	40	30
CP Effectiveness Factor	E_{cp}	1	2
Coating Type Factor	CT	2	2
Soil Factor	SF	5	10
Corrosion Incidents/Mi/Yr	C_9	0	0.02
Maximum Allowable Operating Pressure, psig	MAOP	824	936
Hydrostatic Test Pressure, psig	HTP	1482	1170
Seam Factor	C_{10}	1	1
Girth Weld Factor	C_{11}	1.25	1
Class Location	CL	3	1
Throughout Loss Factor	C_{12}	1	2
Customer Interrupt Factor	C_{13}	2	1
Probability of Failure, Outside Force	P_{of}	6760	1560
Probability of Failure, Corrosion	P_{cor}	89	1778
Probability of Failure, Manufacturing/Construction	P_{mc}	224	560
Consequences	Q	17654	10253
Rank	R	124864	39966

1

$$P_{of} = \left(\frac{1}{t^2} + \frac{12}{D} \right) \left(\frac{100{,}000}{SMYS} + \frac{10}{\sqrt{CVN}} + C_1 \right) \left(\frac{3}{d_c} \right)^{1.5} (1 + 0.1C_2 + C_3 + 100C_4)\,(1 + 5C_5 + 5C_6 + C_7 + C_8)$$

2

$$P_{cor} + \left(\frac{1}{t} \right) \left(8T_1 + \frac{E_{cp}}{3} T_2 \right) \left(\frac{CT}{6} \right) (SF)\,(1 + 50C_9)$$

3

$$P_{mc} = \left(\frac{MAOP}{HTP - MAOP} \right) (100 + T_1 + T_2)\,(C_{10})\,(C_{11})$$

4

$$Q = (CL)\,(MAOP)\,(D)^{0.5}\,(C_{12})\,(C_{13})$$

5

$$R = (P_{of} + P_{cor} + P_{mc})\,Q / 1000$$

6

$$F_{ILI} = \frac{T_{NOW} - T_{ILI} + 1}{10}$$

7

$$F_{HRT} = \frac{T_{NOW} - T_{HRT} + 1}{5}$$

Figure 1. Summary of Equations for a Simple, Generic Ranking Model

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