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Process safety management in the pipeline industry: parallels and differences between the pipeline integrity management (IMP) rule of the Office of Pipeline Safety and the PSM/RMP approach for process facilities

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Abstract

In 2001, the Federal Office of Pipeline Safety promulgated its pipeline integrity management rule for hazardous liquid pipelines. A notice of proposed rule making for a similar rule for gas pipelines was issued in January 2003. A final rule must be in place by the end of 2003. These rules derive from formal risk management initiatives of both the pipeline industry and the regulators beginning in the early to mid-1990s. The initiatives and resulting rules built on many of the process safety and risk management concepts and frameworks of the process industries, as modified for pipelines. Looking closely at the parallels and the differences is an interesting study of how the technical, public and industry-specific requirements affect the types of regulations, supporting management system frameworks and the technical activities for improving hazardous materials process safety. This paper is based on the experience of the author in project work with federal and state regulators and with industry groups and companies, in both the process and pipeline industries over the last 17 years. It provides insights into various alternative pathways for communicating process safety concepts and improving process safety as the concepts are translated into specific company and even individual employee actions. It specifically highlights how the commonalities and differences in the types and configurations of physical assets and operating practices of the pipeline companies and process facilities affect respective cultures, language and actions for process safety management.

Keywords: Process safety; Process safety management; Integrity management; Pipelines; Risk management; Process facilities; IMP; PSM; RMP; Regulations

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1. Introduction

Large pipeline systems complement the nation's process industries infrastructure by transporting hazardous substances to and from process facilities. In some cases, the owners and operators of the process facilities also own the pipelines. In other cases, the pipelines are common carriers servicing multiple customers. In 2001, the Federal Office of Pipeline Safety (OPS) issued new regulations for pipeline integrity management in high consequence areas (HCAs) that establishes requirements for integrity management programs (IMP) for hazardous liquid pipelines under federal regulatory jurisdiction. A proposed, analogous rule for gas pipelines is required to be in place by the end of 2003. The liquids IMP rule was inserted as § 195.452 of the existing federal hazardous liquid pipeline regulations, Title 49 Code of Federal Regulations Part 195 (49 CFR Part 195). The rule for gas pipelines will similarly be inserted within the existing gas pipeline regulations, 49 CFR Part 192.

The IMP initiative can be viewed as another example of federal codification of formal risk management processes for hazardous materials that has characterized the 1990s regulatory agenda. The Occupational Health and Safety Administration (OSHA), Process Safety Management (PSM) regulation in 1992 (29 CFR Part 1910) and the US Environmental Protection Agency (EPA) Accidental Release Prevention, Risk Management Program (RMP) regulation in 1996 (40 CFR Part 68) are other examples of this type of safety regulation.

This paper shows that the pipeline IMP program and PSM/RMP appear to share a common framework of operational risk management (ORM). The PSM program was designed specifically to address worker safety while the RMP extended those principles to protect community safety. The IMP addresses both.

Rather than a solely prescriptive, checklist type of regulation, these regulatory programs define management systems that attempt to unify multiple individual activities which affect process safety. The intent is that within the formal structure of a defined framework, subject matter experts will more efficiently and effectively act and communicate to identify, select and implement appropriate control measures for enhanced safety. As such, these programs comprise a framework of formal risk management systems for accidental releases of hazardous materials.

The purpose of this paper is to illustrate the parallels and differences so that both pipeline operators and process operators can expand their technical resources for process safety and equipment integrity by mutual exchange of information and lessons learned. The goal is to aid in communications, technology and knowledge transfer, increase mutual awareness, promote out-of-the-sector thinking, and exchange lessons learned that are generic in their application.

2. The setting

Both IMP and PSM/RMP define management systems for the prevention and mitigation of accidental releases of hazardous substances. From the pipeline industry point of view, this is expressed as ensuring the physical integrity of the pipe (and other hardware). For the process industries this is expressed as process safety and accidental release prevention. This is our first example of the "cultural" differences in different sectors in their respective expressions of the same issues. They employ a different lexicon. Identifying the causes of equipment failure and resultant accidental releases and controlling them is the fundamental component of a prevention program. This activity of identification may be more complex with a chemical process than for a pipeline. But the pipeline is subject to less controllable variables or risk factors, even though they may be easier to identify. Examples of causes of releases for the process industries and pipelines are discussed later in this paper under performance measures.

The US Department of Transportation, Office of Pipeline Safety (OPS) oversees 2.2 million miles of pipeline, of which about 157,000 miles carry more than 550 billion gal annually of crude oil and petroleum products [10]. The natural gas pipeline system consists of approximately 333,000 miles of transmission pipeline and 1.7 million miles of distribution pipelines [10].

The process industries to which the PSM/RMP applies comprises approximately 14,828 facilities and 20,210 processes, subject to those rules [3]. Processes with major flammable mixtures, propane, and other common flammable gases comprise about 25% of the processes.

The relatively low safety and environmental risks of pipelines compared with other means of fuel transportation, based on a ton–mile of fuel transported, have not offset concerns resulting from some high consequence accidents. Pipeline industry critics take little comfort in the estimated fatalities per billion ton–miles of about 0.03 for pipelines compared with 1.2 for rail and 9.22 for highway transportation [5].

A comparison of the pipeline industry with the process industries is instructive. For the process industries, during the period from 1994 to 1999, the period for which centralized process industry data for tracking in RMP*Info [3] are available, there were approximately 2000 accidents resulting in 1897 on-site injuries and 33 on-site deaths. Offsite consequences were reported in terms of 154 evacuations affecting 25,745 evacuees, and 97 shelter in place accidents confining 198,460 people in total [3].

During the same general period, data from the OPS databases of reportable incidents and accidents shows that there were 448 natural gas transmission line incidents and 1119 liquid transmission line accidents (the difference in terminology, i.e. incident vs. accident, reflects OPS usage and the preferred usage in the respective pipeline industry sectors) [12]. The gas incidents resulted in 217 injuries and 58 fatalities. The liquid accidents resulted in 55 injuries and 14 fatalities. The majority of the casualties in both cases are employees or contractors of the company.

These data are not normalized on a per mile or facility basis. Because of the nature of a pipeline relative to a fixed facility it is difficult to compare numbers between pipelines and fixed process facilities. Performance measure issues are discussed later in this paper. Some normalization of data, the shows the effects of data analysis on the interpretation of gas pipeline incident data, is presented in the technical literature [4].

3. Pipeline risk management

In the mid-1990s, a joint working group of government, liquid and gas pipeline representatives and their contractors joined efforts to better define risk management practices in both

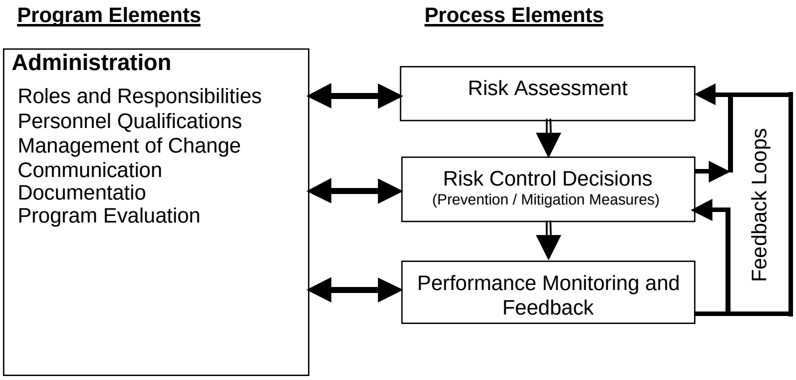

Fig. 1. An overall risk management framework. Adapted from [13].

the gas and liquid pipeline industries. The purpose of this working group was to establish a common framework for pipeline risk management, in conjunction with an OPS risk management demonstration program. This program was authorized by the Pipeline Accountability and Partnership Act of 1996. The result was a series of technical documents culminating in the "Risk Management Program Standard", issued through OPS in 1997 [12]. The program standard defines the concept of program elements and process elements of a pipeline risk management program. The purpose of the standard at the time it was issued was to provide a risk management framework that could be used for the risk management demonstration program, however, the author believes that its applicability has been demonstrated to go beyond just that program. The relationship between what constitute program elements and process elements is illustrated in Fig. 1. Program elements address the administrative parts of the program that integrate the program into a company's day-to-day business practices. The program elements include: clearly defined roles and responsibilities, internal and external communication, training specific to risk management, management of change, performance evaluation and improvement, and other processes as might be appropriate. The technical details of risk management make up the process elements. These include the processes and tools to assess risks, identify methods of controlling risk, allocate resources to control risk, monitor performance, and apply information learned to continually improve the process.

4. Integrity management

Effective from May 29, 2001, for hazardous liquid pipeline operators with more than 500 miles of pipeline, the Code of Federal Regulations (CFR) established new requirements for "pipeline integrity management in HCAs". The same requirements were enacted in February 2002 for systems with less than 500 miles of pipeline and similar requirements, though with more focus on safety issues, are expected in the near future for natural gas pipeline operators.

The IMP rule embodies many concepts and practices manifest in the OPS Risk Management Demonstration Program for pipelines and Risk Management Program Standard. An

IMP consists of eight basic process elements:

- HCA identification process;
- baseline assessment plan;
- integrated information analysis;
- repair criteria;
- continual pipeline assessment and evaluation process;
- identification of preventative and mitigative measures;
- methods to measure the integrity program's effectiveness;
- integrity assessment results and information analysis review by qualified person.

In addition to these basic process elements, listed above, there must be a written IMP describing the various processes for meeting the regulatory requirements and referencing various administrative procedures for the IMP's implementation, execution and integration into the existing operational and business processes.

The IMP rule defines HCAs as commercially navigable waterways, high population areas, other populated areas, and unusually sensitive environmental areas as defined in 49 CFR § 195.6. It applies to segments of a pipeline system that lie within the boundaries of an HCA or those from which a leak or spill could affect an HCA, even if the segments are not within an HCA's boundaries. Identification of such "HCA segments" is the first requirement of the IMP rule. This is discussed further later in this paper.

This initial screening or analysis of HCA's acknowledges that those pipeline segments that could affect an HCA are potentially higher risk segments than those that cannot affect an HCA. The information integration process for the ongoing program then requires risk assessment for decisions about integrity assessment, which is specifically defined as internal line inspection (ILI), pressure testing (PT), or other equivalent means to determine pipeline integrity. Risk assessment is also the tool leading to the decision process for prevention and mitigation measures. An interactive and iterative process of continuous improvement is envisioned with progress determined through performance measures.

5. Comparison between IMP and PSM/RMP

An implementation framework for the IMP elements is illustrated in Fig. 2. This is aligned for comparison to a PSM/RMP framework shown in Fig. 3. The PSM/RMP requirements were studied as background during development of the OPS, "Risk Management Program Standard", so the alignment is not coincidental.

The IMP rule defines a risk-based approach for classifying pipeline segments for inspection, testing, prevention and mitigation measures based on their proximity to and potential effects on HCAs. Different requirements apply to pipeline segments based on the relative risks of each segment as evaluated through an integrated information analysis process that includes risk assessment. The IMP mandates a formal process for risk-based decision making to control risks through enhanced pipeline integrity management. Therefore, successful implementation of an IMP requires a thorough understanding of risk assessment and risk management as they apply to pipelines.

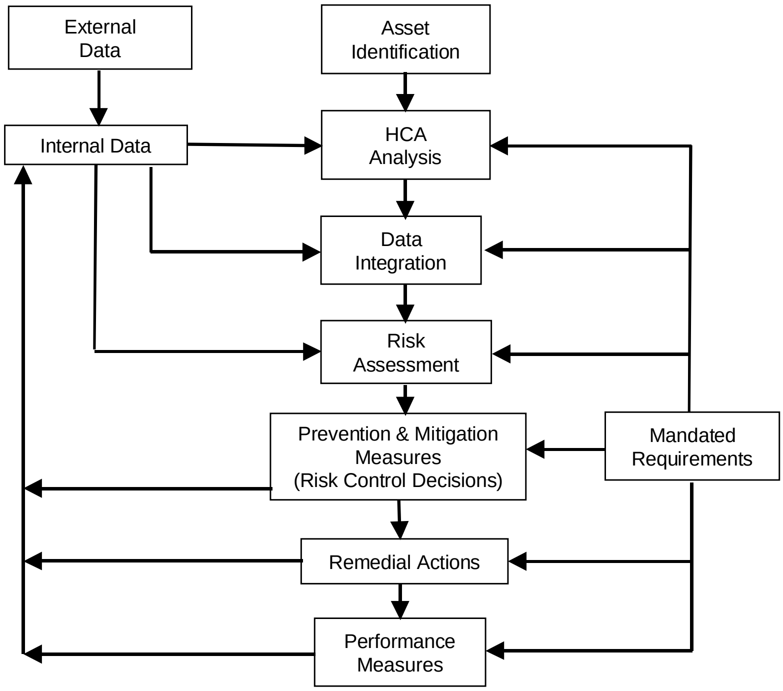

Fig. 2. An integrity management process framework.

Both IMP and PSM/RMP define a management process for the prevention and mitigation of accidental releases of hazardous substances. From the pipeline industry point of view, this is expressed as ensuring the physical integrity of the pipe (and other hardware). For the process industries this is expressed as process safety and accidental release prevention. The use of different expressions for the same issues illustrates some of the “cultural” differences between the two industry sectors. Identifying the causes of equipment failure and resultant accidental releases through risk assessment and controlling them through prevention and mitigation measures are fundamental to each risk management process.

Tables 1 and 2 show a more detailed comparison between the PSM/RMP elements and IMP elements. These comparisons illustrate the effect of different industry sector perspectives on the application of fundamental risk management process elements.

These tables show parallels between the IMP rule and the risk management systems embodied through PSM/RMP. They show that much of the structure and elements within the IMP have precedence in other programs from which technical literature and expertise could be applied to expedite the successful implementation of an IMP. The IMP rule, however, seems to address more explicitly the integration of information and more definitive requirements for consequence analysis.

In spite of these commonalities, the IMP rule requires formal risk assessments, discussed in more detail in the following section, and an explicit requirement that “effectiveness measures” be defined from the start of the program. The IMP explicitly requires documented

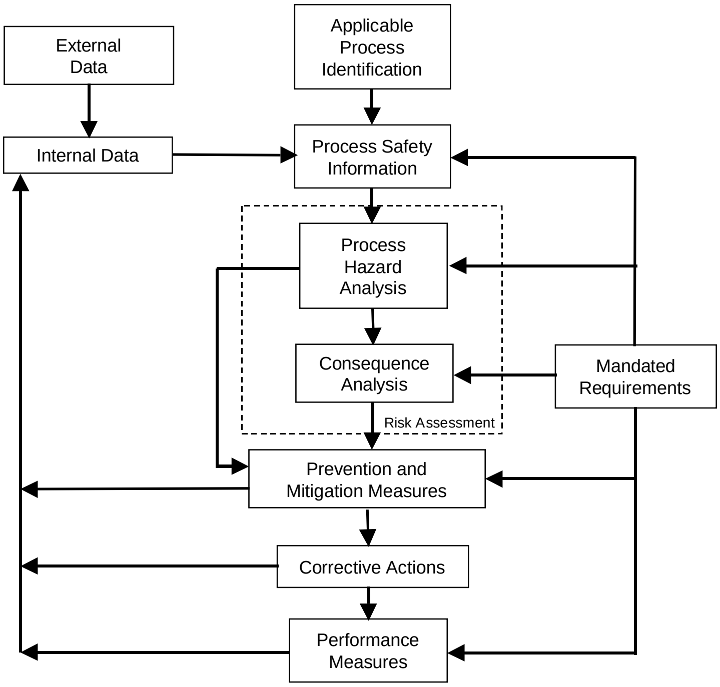

Fig. 3. A PSM/RMP process framework.

risk assessment as a basis for prevention and mitigation decisions. PSM/RMP allows for formal risk assessment as a logical progression from process hazard analysis (PHA) and offsite consequence analysis (OCA) but does not require it as a mandated decision tool.

To summarize, the preceding comparison reveals that:

- The alignment illustrates the underlying fundamental risk management framework is present in both IMP and PSM/RMP.
- Differences reflect the language, culture and preferences of different industries and their respective different types of assets.
- Differences also reflect the perceptions of different individuals and the corresponding consensus teams that developed the various programs.
- All the above underscore the importance of understanding the parallels and differences in process safety and other types of management systems as a basis for effective communications, training and execution of such programs to meet process safety and equipment integrity risk management objectives.

6. Detailed comparisons of selected process elements

With the framework comparison completed, we look next on some of the specific process elements of IMP in more detail, in comparison with similar PSM/RMP requirements. The

Table 1
Comparison of risk management program elements

Risk management program elements	OSHA PSM	EPA RMP	OPS IMP
Goals	Broad goals stated in regulation	Broad goals stated in regulation	Broad goals stated in regulation
Administration		Management system	Written documentation
	Responsibility implicit in process elements (see Table 2)	Responsibility implicit in process elements (see Table 2)	Responsibilities implicit in process elements (see Table 2)
	Employee involvement	Employee involvement	
	Employee training	Employee training	
Management of change	Management of change	Incorporates OSHA PSM requirements	Justification of decisions related to pipeline integrity actions
Information management	Written documentation	Written documentation internally and RM plan summary submission to agency	Written IMP Supporting documentation Integration of all information pertinent to pipeline integrity No submission to agency required
Program evaluation and improvement	Implicit through stated goals Compliance audits	Implicit through stated goals Compliance audits	Requires the selection and monitoring of performance measures Audits

Table 2
Comparison of risk management process elements for prevention with risk factors addressed[a]

PSM/RMP prevention element	Risk factor specifically addressed	IMP prevention element
Employee participation	Adequate data and information Employee awareness and training Employee attitudes	Integration of all pertinent data Prevention through enhanced capture of employee knowledge
Process safety information	Adequate data and information Assurance of up-to-date data and drawings	Integration of all pertinent data Integrity assessment results Risk assessment (requires information of system transported assets process)
PHA	Identification of causes and consequences for accidental releases	Integration of all pertinent data and risk assessment
Operation procedures	Adequate documentation of proper procedures to prevent human error	Documentation requirements and integration with existing written operating procedures regulatory requirement
Training	Employee awareness and training Employee attitudes Prevention of operator error	Addressed for specific IMP activities in element 8 Integration of IMP requirements into existing regulations for training and operator qualification
Contractors	Prevention of errors by contract employees	Implicitly addressed by connection of IMP to the OPS Operator Qualification Rule 49 CFR Part 192, Subpart N and 49 CFR Part 195 Subpart G
Pre-startup safety review	Oversight of a flaw that could lead to a failure on startup	Integrated information analysis and risk assessment Prevention and mitigation measures
Mechanical integrity	Inspect, test and maintain equipment to prevent accidental releases through equipment failure	In essence the entire IMP Specifically, integrity assessment Prevention and mitigation measures
Hot work permit	Prevention of releases and fire explosions by strict control of welding as potential failure mechanism and ignition source.	Prevention and mitigation measures
Management of change	Prevention of releases by inappropriate process, equipment, or procedural change	Integrated information analysis, risk assessment, and feedback
Incident investigation	Prevention of releases by garnering new knowledge of causes and prevention measures from lessons learned	Prevention and mitigation measures and feedback
Emergency planning and response	Mitigation of releases by adequate emergency response procedures and resources	Prevention and mitigation measures HCA analysis Leak detection analysis

Table 2 (*Continued*)

PSM/RMP prevention element	Risk factor specifically addressed	IMP prevention element
		EFRD evaluation
		Incorporation of IMP findings/experience into existing emergency response plan requirement
		Communications
Compliance audits	Verification of compliance with external and internal requirements of PSM	Integrated information analysis process

[a] The IMP is part of an existing regulatory structure that has a separate regulation for operator qualifications. Employee participation is inferred from IMP rule requirements rather than expressly stated.

IMP elements reviewed include (with some additional interpretive language, in parentheses):

- HCA identification (and consequence analysis/modeling), with differences for liquid and gas pipelines;
- integrated information analysis (and risk assessment);
- prevention and mitigation measures;
- measures of program effectiveness (performance measurement).

(These represent only some of the elements of a complete program.)

6.1. HCA identification and consequence analysis

The HCA identification requirement is one way in which the IMP differs from PSM/RMP. IMP applicability is based, in part, on the definition of assets according to geographic location in addition to other attributes of the system. This geographic element introduces consideration for the potential sensitivity of both people and environmental receptors to accidental releases at the very beginning of program development. It is a more direct embodiment of the same principle reflected in the PSM/RMP concern for threshold quantities. There, the potential for impacts is based on the potential for a threatening quantity of hazardous material to be present at a given location. For a pipeline, this principle is expressed as the potential for the presence of sensitive receptors near the pipeline. These different approaches reflect the differences in the nature of the assets and their location characteristics (fixed vs. widely distributed location of release points).

For liquid pipelines, OPS developed a series of GIS-based maps for the whole country that identify and show boundaries for HCAs, which are:

- high population areas (HPA);
- other population areas (OPS);
- navigable waterways (NW);
- drinking water supplies (DWS);
- ecological areas (ECO).

HCAs for gas pipelines are defined in terms of several population specifications.

Pipeline operators were asked to submit their pipeline locations to OPS for loading into the GIS as part of the National Pipeline Mapping System (NPMS) project. The maps were then made available for an operator to download by Internet access in order to identify his HCA pipeline segments. If 49 CFR Part 195 regulated pipeline assets lie within an HCA, they are subject to the IMP rule. Line pipe segments or other pipeline assets (e.g. pump stations) within an HCA are subject to the corresponding parts of the IMP rule that apply to them. However, the IMP also designates as affected assets those that are located near enough to an HCA such that they "could affect" an HCA. It is the responsibility of the operator to identify these parts of their systems. In addition to OPS designated HCAs, it is also the responsibility of the operator to identify other HCAs that might not have been identified on OPS maps. The IMP rule requires that the operator have a formal process for HCA identification both initially and in perpetuity, to allow for changes that might occur along the pipeline route over time. The same principle will apply for gas pipelines except that the current definition of HCAs focuses on population rather than environmental features.

The HCA identification element combined with the requirement for integrated information analysis and risk assessment amounts to an OCA, to use the PSM/RMP terminology. However, in the context of all the requirements of the IMP rule, the IMP requires a more detailed analysis of some impacts than the PSM/RMP regulation. The feature of the IMP that drives this is the need to identify pipeline segments that "could affect" an HCA rather than those that actually lie within an HCA.

6.1.1. Consequence analysis for liquid releases

The consequences of liquid leaks or spills depend on where the liquid flows, how much evaporates and whether ignition occurs for flammable materials. Although the IMP rule requires assessing liquid spill impacts as well as air dispersion impacts of volatile liquid vapors (and for the gas pipeline rule, a thermal radiation threshold), it does not specify conditions for release modeling as does PSM/RMP. The proposed gas pipeline IMP refers to specific modeling results and the methods for their derivation.

Initially, many liquid pipeline companies responded by establishing a simple corridor approach. In this approach, they selected a standard distance from the centerline of the pipe as defining a zone of impact for a spill. If an HCA boundary touched or lay within this zone, the segment within that distance of the pipeline was designated as an HCA segment.

This approach may not be adequate, in all cases, for two reasons. For liquid releases that result in overland flow, the local topography will significantly affect the potential to affect a nearby HCA. Subsurface releases may also affect an HCA and again because of an area's subsurface geology, a simple corridor approach may be inadequate. Also, for liquid pipelines there is the potential for vapor dispersion and the attendant impacts, with or without ignition.

More refined modeling accounts for local terrain features such as slope gradients and localized flow channels. At the more refined levels of assessment, these can lead to quite different conclusions about risk for a given pipeline segment. This can be important for those marginal cases where a determination is needed about a pipe segment's potential to affect a nearby HCA when the pipe does not actually run through it.

Fig. 4 illustrates the significance of considering the actual terrain compared with a simple corridor approach. The drainage patterns near pipelines can drastically alter the potential

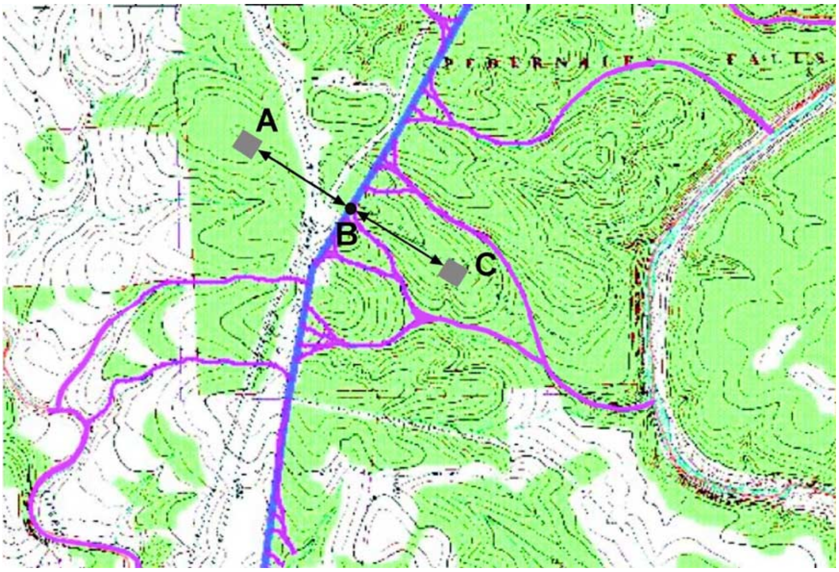

Fig. 4. Example of topographical effects on flow pathways for pipeline liquid releases, where potential impacts at C exceed those at A.

environmental and safety consequences of a failure. Points A and C are equidistant from the release point B, but the potential impact differences are clear. The potential impact at C exceeds the potential impact at A.

6.1.2. Consequence analysis for gas releases

Vapor or gas dispersion from pipelines would be modeled in the same general manner as for releases from fixed facilities under PSM/RMP. However for pipelines, the vulnerability zone might be represented by a corridor along the length of the pipeline rather than emanating from a single, fixed point. The simplified model for PSM/RMP regulatory compliance would likely be inadequate. Under IMP more realistic, less conservative impacts analyses are needed to support formal risk-based decision making along with the technical justification for those decisions.

For the proposed gas pipeline rule, HCAs have been defined as specified types of population areas (e.g. Class 3 and 4 areas with less mobile people). The concept to HCA segment is retained but it applies to pipelines within or that could affect such a populated area. The primary irreversible effect is on people and not environmental impacts.

Natural gas pipelines comprise 90% or more of mileage likely to be affected by the IMP for gas pipelines. For these pipeline systems the primary hazard is fire. Historical experience suggests that serious incidents, other than a jet fire, have rarely, if ever occurred for these pipeline systems.

In January 2001, the Gas Technology Institute (GTI), under the Gas Research Institute (GRI) label, released a report that examined the impact distances of jet fires from high pressure natural gas transmission lines [6]. The report showed the impacts for various pressure and line sizes. Covering essentially the range of conditions likely to be found for gas pipelines, the report's results were also incorporated into the ASME B31.8 Supplement for Integrity Management of Gas Pipelines [1]. What these documents do not address is the question of under what circumstances, such as confinement of the escaped gas, it might be possible for a high pressure, natural gas pipeline to lead to a flash fire or gas cloud explosion rather than a jet fire. Based on experience with high pressure pipelines, the proposed gas IMP rule assumes that the primary impact upon ignition will result from a jet fire. EPA Offsite Consequence Analysis Guidance (OCAG) [14], which does examine impacts from flash fires and gas explosions, tends to overstate the effects. More refined models are available to the industry, if needed, for alternative analyses.

Compared with RMP OCA, the consequence analyses associated with IMP may exhibit the following:

- more detailed analyses and more focus on liquid leak and spills modeling rather than vapor or gas dispersion;
- usually, more attention for near-field impacts (within 0.1–0.5 mile of release point);
- more flammables than toxics modeling;
- appropriate conservative modeling results than those yielded by OCAG.

In summary, some of the same general types of modeling used for RMP OCA are being or will be applied for pipelines in the IMP program. Liquids and gas impact modeling may use different models. Unlike RMP, the liquid IMP rule does not explicitly require such modeling, but the requirements of IMP strongly imply that it needs to be done. For gas pipelines, standard distances related to pipeline and operational parameters might provide a basis for examining potential consequences. For liquid pipelines, a more detailed protocol would be required. The modeling for pipelines differs from RMP in the fundamental way that it can be used in actually establishing the applicability of the regulation to specific assets.

6.2. Integrated information analysis (and risk assessment)

The IMP rule calls for an integrated information analysis and risk assessment. This requirement appears to be analogous the PSM/RMP requirement for a PHA. Formal risk assessment is at the core of integrity management. Risk assessment is used in:

- setting priorities for maintenance, repairs and rehabilitation;
- setting priorities for inspection and testing (integrity assessment, as defined under the new IMP rule);
- setting priorities for enhanced prevention and mitigation measures;
- comparing the relative effectiveness of alternative prevention and mitigation measures;
- comparing different routing options;
- evaluating the financial impacts of alternatives, including probabilistic events.

An initial risk assessment helps to set priorities during the HCA identification and baseline assessment planning. After integrity assessment, a risk assessment is used to help establish priorities for future integrity assessment schedules, remedial repairs or other actions. At the same time or after integrity assessment, risk assessment is again used in the identification and selection of additional prevention and mitigation measures.

The important point is that if one understands the basic structure of risk management and its components, including risk assessment, the kinds of programs called for by regulation follow naturally. In fact, current practices, without the regulations actually follow the same process in a less disciplined and systematic way. What the regulations do, both PSM/RMP and IMP is to discipline and systematize the processes for consistency, rigor and improved effectiveness.

6.2.1. Pipeline risk factors

Factors for a risk analysis involve a number of variables associated with the pipeline itself and its location relative to sensitive receptors. The variables relate to the probability and consequences of a release. In the pipeline industry and IMP rule, the term "risk factors" is used for these variables, which represent both attributes of the system and its setting. The IMP rule lists some examples of specific risk factors, which represent a minimum of what should be considered in risk assessment. It is expected that an operator will introduce more risk factors into their individual risk assessment. The regulatory prescription in the IMP and emphasis on a formal risk assessment process is similar to PSM/RMP, which address these concepts in terms of a hazard analysis and OCA.

The IMP rule defines a number of risk factors related to the likelihood of pipeline failure. These factors are consistent with the many factors recognized by industry and accounted for in the various risk assessment tools that are used by some pipeline operators. Because failure is never the result of single event, but rather a series of succeeding events over a period, integration of multiple factors into a risk assessment is required.

In general, some major factors, not necessarily all, related to the probability include:

- size, year of installation, type of pipeline and operating pressure;
- product transported;
- location of the line, relative to natural and man-made threats.

The probability is driven by a number of factors, such as deterioration through corrosion or damage from outside forces (e.g. from someone digging into a line). The consequences depend on the nature and quantity of the substance released if a pipeline fails and the separation distance between the pipeline, people, and other sensitive receptors.

An estimate of the probability of such failures can be estimated from historical data on similar systems. Such data are available in public records of incident reports. The consequences of failures can be estimated based on historical and experimental evidence. These data are combined in the risk analysis to provide a quantitative estimate of the risk to people within specified distances of a pipeline.

Some major factors, not necessarily all, related to consequences include:

- the same three as above for probability;
- proximity of the line to sensitive receptors;
- meteorological conditions;
- local terrain, topography and land use.

Probability factors address causes for releases. Causes for pipeline releases are generally known and various listings can be found in the technical literature. However, there has not traditionally been a standard lexicon for describing causes. Table 3 lists the incident causes

Table 3
Approximate alignment of some example cause categories and causes for the process and pipeline industries[a]

Major process industry causes for piping failures		Pipeline industry causes (for gas pipelines) [10]	Some examples of how category addressed as risk factors in typical pipeline relative risk tool
Example 1[b] [7]	Example 2[c] [7]		
Impact	Impact	Third party damage	Third party damage factors
Restraint	External load		Design factors
Corrosion	Corrosion	Corrosion	Corrosion factors
Erosion	Erosion		Corrosion factors
		Natural forces	Design factors
			Soil movement
			Flood potential
	Operator error	Incorrect operations	Incorrect operations
			Hazard identification method
			MAOP potential
			Safety systems type
			Material selection verification
			Construction actions
			Operating procedures
			SCADA/communications
			Surveys
			Training
Vibration	Vibration		
Freezing	Extreme temperature		
Thermal fatigue			
Water hammer	Overpressure		
Work system	Wrong equipment		
Mechanical			
		Miscellaneous	Maintenance documentation
			Maintenance schedule
			Maintenance procedures
Unknown	Unknown	Unknown	Not relevant to modeling
Unspecified			
	Other	Other failures	Design factors
			Pipe safety factor
			System safety factor (P/PM ratio)
			Fatigue surge potential
Material	Defective pipe or equipment	Manufacture	Design factors
			Hydrostatic test pressure
			Time between test
		Construction/installation	Incorrect operations factors
		Previously damaged pipe	Third party damage factors
			Incorrect operations factors (e.g. failure to inspect or test)
		Malfunction	Design factors
			Incorrect operations factors
		Stress corrosion cracking	Corrosion factors
		Vandalism	Security factors

[a] Conceptual levels of causes in the event change, with inconsistencies, and differing terminology's preclude a precise "conceptually pure" alignment at this time.

[b] From Blything and Parry (1986), SRD R441, as reported in [7, p. 12/102, Table 12.16].

[c] From Ballamy et al. (1989), as reported in [7, p. 12/105, Table 12.20].

for process plant piping [7] compared to pipeline systems [10]. A major issue in all such data, illustrated here, is that the differences in classification schemes makes dealing with comparisons of such data difficult. This issue continues to be studied by both industry and government. The most notable difference between the industries and respective types of facilities reflected here is that direct outside forces, mechanical damage (i.e. third party damage) is a major cause of pipeline incidents, whereas process incidents are more influenced by factors internal to the systems. In spite of these differences, there is a common framework in which these causes are being addressed for improved control.

6.2.2. Pipeline risk analysis methods

Risk assessment methods in either the process or pipeline industries are based on a classic definition of risk in a form as

$$\text{Risk} = \text{event likelihood} \times \text{severity of event consequences}$$

As in the process industries, two basic classes of risk analysis methods are qualitative and quantitative methods. Pipeline operators use both methods to organize large amounts of information before making pipeline rehabilitation and repair decisions.

6.2.2.1. Qualitative methods. Qualitative methods may focus only on relative consequences or assess the probability and consequences in relative terms, such as high, medium and low. Qualitative approaches combining probability and consequences often use numerical scoring methods to generate a relative risk ranking of pipeline segments along a pipeline route. These methods define a number of risk factors, each of which is assigned a numerical value. The factors are mathematically combined, usually by addition, to yield a numerical score value for each predefined segment length of pipeline. In this manner, segments can be ranked and grouped according to relative risk.

The various methods in commercial use each deal with both the probability and consequences of leaks or spills in such a manner that the ranking reflects a total risk rather than just the likelihood of a pipeline failure (e.g. [2,9]). In essence these tools are similar to qualitative methods used in the process industries, such as the Dow Fire and Explosion indices [7]. Ranking of pipeline segments is analogous to ranking processes or equipment items. However, the pipeline industry’s tools are undergoing rapid change brought on by more intense use as a result of the new demands for integrity management.

6.2.2.2. Quantitative methods. Quantitative or probabilistic methods are also used in the pipeline industry. These include the same fault tree and event tree methods used in the process industries. In addition to probabilistic estimates based on historical data for a leak or spill, there are specialized methods for predicting the effects of known defects, such as corrosion areas or cracks, on the likelihood of failure within a specified time span. Such methods are used in setting re-inspection and testing intervals based on known conditions.

6.2.3. Pipeline applications

It appears that the relative risk assessment methods generally are in wider use at the present time for pipelines. In practice, usage of both qualitative and quantitative methods continues to grow, and there might be possible benefits to a combination of both methods [8].

An IMP uses risk assessment for three specific purposes. The first is in ranking HCA segments, already discussed. The second and third relate directly to prevention and mitigation measures. Integrity assessment the prevention measure of explicitly defined inspection and testing for line pipe that is to be based on a relative risk ranking of individual line pipe segments. The baseline assessment plan is divided into two phases, over a 7-year period where the first phase addresses the "highest risk" segments. Therefore, a risk assessment tool helps to establish priorities.

Subsequently to the baseline integrity assessment, results are used in further risk assessment to identify and select appropriate remedial actions and additional prevention and mitigation measures. However, the use of risk assessment for some prevention and mitigation measures analysis can also proceed in parallel with the integrity assessment. This is because the prevention and mitigation analysis is the vehicle for identifying additional actions for line pipe as well as for other components of the pipeline (e.g. breakout tanks, values, leak detection capability, emergency flow restriction devices (EFRDs), etc.). There must also be a rational basis for selecting reassessment intervals as an outcome of the inspection and testing results. Risk assessment results are a decision aid in this process.

The "risk process", that is the entire approach for risk assessment including the compilation of data, the risk assessment method and the interpretation and use of the results, must be documented by description. Technical assumptions and bases for the analyses must be documented. The IMP rule mandates certain risk factors that must be considered and expects that others will be included. Appendix C of the IMP rule also provides a simplified relative risk ranking methodology. This differs from PSM/RMP where a hazard analysis but not specifically a risk assess is required. Details of factors to be considered are not specified in those regulations. For pipelines, the details of the risk assessment also are subject to detailed review by OPS inspectors. Because the IMP rule requires the integration of all pertinent data, inspectors will make a judgement regarding adequate inclusion and use of data. They also intend to make a judgement on the adequacy of pipeline segmentation for ranking.

The individual "units" that must be assessed for a line pipe risk assessment are individual pipeline segments of varying lengths. Pipelines are naturally segmented based on the spacing of pump (or compressor) stations and block valves. There were cases of some operators considering proceeding on that basis. However, segmentation solely based on these "natural nodes" along the pipeline is generally inadequate (based on industry experience) and a finer degree of segmentation is expected. What is done currently is reflected in some actual cases where in one case a 500–1000 mile pipeline was segmented into several hundred segments and in another several thousand segments. It remains to be seen how industry responds to the segmentation issue for risk assessment. An important part of the part of the risk assessment process documentation is the rationale for segmentation, which is related to changes in system attributes along the route.

There is a difference between an IMP risk assessment and PSM/RMP PHA. In the latter, the number of equipment items is fixed, and nodes within, for example, a HAZOP are well defined. Because for line pipe, causes are relatively well identified, there is more emphasis with risk assessment than hazard identification by what-if or HAZOP methods. For reasons already discussed, there is a need to estimate relative risk along the line. On the other hand, for the fixed facilities associated with a pipeline, such as pump (or compressor) stations, these methods, commonly used in process industry PSM/RMP PHAs, are found among some of the pipeline operators. Their use appears to be increasing.

6.2.4. Example of a typical qualitative or relative model structure

An illustrative example is presented of a typical qualitative risk assessment tool for line pipe. The example tool examines the likelihood of failure in terms of four categories of risk factors [9]:

- third party damage;
- corrosion;
- design/construction;
- incorrect operation.

A numerical index value is computed for each category. The index values depend on combining other numerical scores determined for several individual variables or risk factors in each category. More details of the method and its application are available in the technical literature [9,15].

The index sum, which is a relative likelihood score, can be combined with a relative consequence factor called the leak impact factor (LIF) to yield a relative risk score. The index sum and LIF can also be used independently and combined with other methods for assessing the complementary term of the risk equation to yield other numerical measures of risk. For example, the LIF can serve as a qualitative consequence analysis but can also be combined with a probabilistic likelihood analysis. Likewise, the index sum can be combined with a quantitative consequence analysis, using some of the more detailed methods, discussed earlier (Fig. 5).

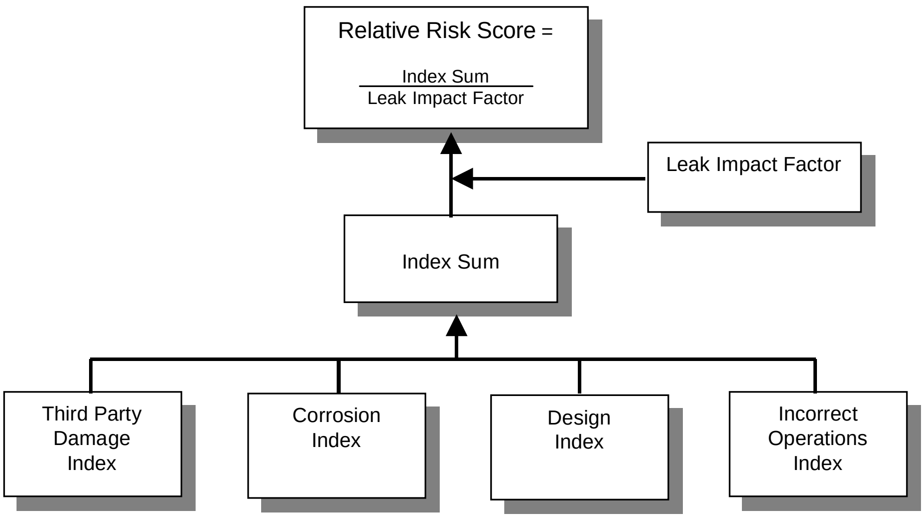

Fig. 5. Example structure of one relative risk assessment tool. Adapted from [9].

It needs to be emphasized that this is only one of several numerical ranking techniques available, some of which are commercially available and some of which are proprietary and developed in-house by an individual operator's own technical staff.

6.3. Examples of other IMP elements

It was not the intent of this paper to exhaustively describe every IMP element and compare it to every PSM/RMP element. However, several additional elements further illustrate the parallels and differences.

6.3.1. Prevention and mitigation measures

The IMP rule differs from PSM/RMP in that it places emphasis on the selection process for prevention and mitigation measures and specifies some required activities rather than leaving their identification strictly to the operator. The IMP rule requires that the operator identify "additional actions" to ensure the integrity of the pipeline. Methods to do this are risk analysis, a leak detection evaluation and an EFRD evaluation. An operator is expected to define a process for identifying and evaluating prevention and mitigation measures and explain and demonstrate how that process is being used. This would be similar to using a PSM/RMP PHA for identifying causes and consequences of failure and identifying the countermeasures or remedies that could be applied to reduce both likelihood and consequences.

All technical assumptions and the bases for the analysis are to be specified and documented. Decision criteria for the prevention and mitigation measures must be noted and justified. The prevention and mitigation measure process must provide for periodic updates, which is analogous to the periodic PHA updates under PSM/RMP.

6.3.2. Performance measures

Improved data collection, evaluation, management, and use are common issues for both the pipeline and process industries. Both the process industry and pipeline sectors face increasing demands on the adequacy, comprehensiveness, quality and usage of data for performance measures. Currently, both industries are focusing increased resources on this issue.

Performance has traditionally been measured on a long-term basis, where general trends of accidents, injuries, fatalities, and property damage are observed over years or even decades. The problem with such performance data is that it measures the aggregate of numerous variables acting together that change over time. It is difficult to attribute improved performance (or the lack thereof) to specific prevention and mitigation measures and their effects on specific risk factors. This in turn slows potential progress by delaying the identification of and modification or additional deployment of the most effective measures. Clearly better measurement of system behavior that provides leading or "feed forward risk control" rather than lagging or "feed back risk control" is preferred. This is a common issue shared by both the pipeline and process industries.

The IMP rule explicitly requires that an IMP define and provide a rationale for "effectiveness" measures for the IMP. The IMP rule, suggests categories and provides examples of specific "performance" measures by which to accomplish this. This is a difference

Table 4
IMP—proposed performance measures

Category	Description	Examples
Activity measures	Monitor surveillance and preventive activities, including periodic audits	Ensure that patrols are being carried out on schedule
Deterioration measures	Identify and track operational and maintenance trends as indicators of problems	Repeated corrosion findings in an small area, i.e. within a few miles may be an indicator of a location specific problem
Failure mechanisms	Direct measurement of release frequencies, sizes and other characteristics	Current incident and accident reporting
Comparisons	Compare segments or pipeline systems with others in the same company	Compare release frequencies for similar system attributes and other conditions
	Compare segments or pipeline systems with others in the industry	

between the written rules for PSM/RMP and IMP. PSM/RMP does not require an explicit definition of or commitment to specific performance measures for monitoring program effectiveness.

Appendix C of the IMP rule explicitly requires setting performance goals in terms of numbers, percentages and other measures of progress for whatever performance measures are selected. Some current performance measures proposed for IMP are summarized in Table 4. The IMP rule also suggests that the performance measurement program could include both internal and external audits.

For the pipeline industry, overall performance in terms of releases, injuries and fatalities is tracked through OPS databases, the content of which are available on line at the OPS website: http://www.rspa.dot.gov. Summary data as well as the detailed databases for both liquid and gas pipelines are available. In addition, regular analyses of these data are published from time to time by others.

In comparison, the process industry does not have a formal data collection mechanism. Multiple databases are maintained by various entities, each different in their coverage and definition of event types, as well as in the span of time covered.

Table 5 compares current overall baseline data for both the pipeline and process industries, using information from several literature sources [3,11,13]. This table highlights the difficulty in comparing data between a pipeline and fixed facilities, due to their unique characteristics. Should one treat a single pipeline system as if it were a fixed facility? Should a specific length of pipeline be used to represent an equivalent process facility or a piece of process equipment (e.g. a pressure vessel)? Why or why not compare a pipeline to in-plant piping?

Why do the comparison at all? The reason for doing the comparison is to allow some kind of benchmarking of the similar types of programs against each other, which should have value in illustrating effects of differences in facilities, program details within an overall framework, and similar factors. For the following table, pipeline data are presented on a per mile basis, as is common basis for normalizing pipeline data.

Table 5
Comparison of “baseline” performance of pipeline and process industry sub-sectors[a]

Pipeline or facility	Period	Unit[b]	Incident frequency (events per year per unit)	Injury frequency (injuries per year per unit)	Fatality frequency (fatalities per year per unit)
Natural gas transmission lines	1986–2000	Mile	2.7E−04	4.6E−05	1.2E−05
	1994–1999	Mile	9.4E−05	1.3E−05	1.5E−06
Hazardous liquid transmission pipelines	1986–2000	Mile	1.2E−03	1.1E−04	1.5E−05
	1994–1999	Mile	4.5E−04	2.5E−05	6.0E−06
Oil refineries (NAIC 32411)	1994–1999	Process	2.4E−02	“2.4E−02” (est.)[a]	“4.1E−04”
		“Item”	“2.4E−03”	“2.4E−03”	“4.1E−05”
Petrochemical plants (NAIC 32511)	1994–1999	Facility	3.4E−02	“3.4E−02”	“5.6E−04”
		“Item”	“3.4E−03”	“3.4E−03”	“5.6E−05”

[a] This table attempts to compare pipeline and process industry performance. Pipeline data are averages obtained from the OPS databases on reportable incidents and accidents and pipeline mileage, both onshore and offshore. Process industry data are based on data from the RMP∗Info database, as reported by Belke [3]. However, for the refinery and petrochemical sub-sectors, Belke reported only incident frequencies. The injury and fatality values in this table are derived based on reported rates for the process industries as a whole per incident applied to the refinery and petrochemical incident rates, and are, therefore, estimated rates only for the petrochemical and refining subsectors of the process industires.

[b] The “item” designation is an approximation based on an assumption of an average of 10 “items” per process for the respective process sub-sectors. The purpose is to relate the process industry statistic more closely to the pipeline statistic for insight into how they might compare, if a proper normalization basis could be defined.

The table is for illustrative purposes only and is not definitive. It does provide some insight into the current state of the process and pipeline industries as a whole, in terms of some performance measures. It also shows the importance of normalizing data, whether across industries or within them. Total counts of events are only meaningful on some per unit basis and comparisons need to be conducted on comparable bases.

7. Compliance scheduling

Similar to PSM/RMP, there is a phased approach to compliance in the IMP rule. This is needed to allow the operators to meet some specific initial requirements and establish the foundations for an ongoing program. As stated earlier, the hazardous liquid operators are currently under IMP regulation and the gas transmission pipeline operators face regulation by the end of 2003. Gas distribution operators, the suppliers to "homes and factories" are expected to be included in some type of program later that parallels the federal program.

One major difference between PSM/RMP and IMP is that the IMP rule has no submission requirement. All records are retained by the operator but are subject to OPS inspection.

8. Summary and conclusions

This paper examines some parallels and differences between the OPS IMP rule for hazardous liquid pipelines (and similar provisions likely for gas pipelines) and the federal PSM/RMP regulations for the process industries within a common risk management framework. Formal PHA or risk assessment is at the heart of both types of programs. There are a variety of choices in methods and degree of resolution or level of detail available in such assessments. There are differences in terminology and emphasis, which reflect both the nature of the physical assets involved and the customs of the respective industry sectors. Understanding the commonalities enhances the exchange of knowledge between sectors for mutual advantage in sharing lessons learned. Understanding the differences permits intelligent analysis and application of the shared knowledge to the specifics of each sector.

Some additional conclusions are:

1. The IMP and PSM/RMP are management systems that seek continuous improvement to change not only what is done, but also how it is done. They are similar in structure and fit within an overall framework for ORM.
2. The IMP differs from PSM/RMP in that it was introduced within an existing safety regulatory framework rather than as a totally new type of regulation for its regulated entities. It is an extension of current safety regulations.
3. The success of all these programs depends on replacement of a static checklist compliance mentality with an active risk management mentality of analysis, formal risk-based decision making, continuous review, and re-evaluation in response to changing conditions.

4. IMP and PSM/RMP both rely on risk assessment as a core risk management process step leading to decisions on risk control measures (prevention and mitigation measures) for accidental releases.
5. The new IMP rule explicitly recognizes the roles of risk assessment, risk control decisions, and an iterative improvement process loop. This is consistent with the risk management process practised in the process industry.
6. Given the many choices for risk assessment, there is a natural evolution underway. As operators apply these risk assessment techniques with increasing frequency and rigor, and simultaneously increase data collection and integration activities, understanding and reliability of pipelines should improve. New tools are making it increasingly feasible to analyze potential risk scenarios and risks more accurately and with greater confidence than before, resulting in a more effective decision process that better allocates limited resources for more effective risk control.
7. The availability and accessibility of the data needed to execute the risk assessments and meet explicit requirements of the IMP, such as technical justification of decisions on integrity assessment methods and prevention and mitigation measures, is a significant success factor for an IMP. This parallels the renewed emphasis on data acquisition, integration and analysis in the process industries.
8. There remains a significant need to improve the collection and analysis of pertinent data through improved industry and government protocols.

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