

translated into improvements in operating procedures and communicated among operators. Effective management of change and quality control/assurance programs will also reduce the likelihood of operator error contributing to pipeline failure. Consensus standards were under development at the time of the INGAA response on qualification and certification of individuals involved in analyzing in-line inspection (ILI) results. INGAA expressed concern about the increased demand for ILI services potentially leading to lengthened time requirements by ILI vendors to produce assessment reports, with related implications to the ability of the industry to meet repair and mitigation requirements.

On the subject of gas storage field pipeline systems, INGAA stated that those in high consequence areas should be treated in the same way as natural gas transmission pipelines.

AGA/APGA also noted that the process for managing pipeline integrity should not be affected by the operating stress level. Lower stress pipeline operators should be required to develop and follow integrity management programs having the same elements as operators of higher stress pipelines. Only the tools and techniques used to assess the pipeline and the reassessment intervals should require customization.

NYGAS indicated that it is important to ensure that staff conducting and analyzing results from assessment of pipeline integrity be qualified. In the cases where the operator qualification rule does not apply, operators must ensure proper qualification of these people, and monitor performance measures designed to reveal potential problems with personnel qualification. NISource commented that there needs to be a clear means of identifying a threat as "significant."

In aggregate these comments are consistent with the RSPA/OPS decisions to require threat-by-threat analysis of the pipelines and to acknowledge the differences in failure mode for pipe operating at stress levels below 30% SMYS by imposing somewhat different requirements for these lines.

#### *Select Appropriate Assessment Technologies*

The third element of integrity management discussed in the June 27, 2001 FR notice, involves identification of potential threats to the pipeline in areas of concern. In the notice we used the following hypotheses to support selection of the assessment technologies best suited to effectively determine the

susceptibility to failure of each pipe segment that could affect an area of potentially high consequences:

- An integrity baseline needs to be established for all pipe segments that could affect an area of potentially high consequences. An operator will need to evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. Based on the type of threat or threats facing a pipeline segment, an operator will choose an appropriate assessment method or methods to assess (*i.e.*, inspect or test) each segment to determine potential problems.

- Time dependent threats will require periodic inspection to characterize changes in their significance.

- Acceptable technologies for assessing integrity include in-line inspection, pressure testing and direct assessment. None of these technologies, individually, is fully capable of characterizing all potential threats to pipeline integrity. (**Note:** RSPA/OPS is co-sponsoring with industry an evaluation of direct assessment technology to determine the conditions under which direct assessment is effective in assessing external corrosion. The effectiveness of direct assessment in assessing other threats (*e.g.*, internal corrosion, stress corrosion cracking) is also under evaluation for validation.

- Unless the operator demonstrates by evaluation that they are not a threat to the integrity of a pipe segment, static threats will require pressure testing at some time during the life of the pipeline. If significant cyclic stress, such as that caused by large pressure fluctuations, is present, then pressure testing, or an equivalent technology, will be required periodically throughout the life of the pipeline. If operating conditions for a pipeline with potential seam problems from manufacture are to be changed significantly, then the pipeline must be pressure tested prior to the change of operation.

- Time-independent threats will require the use of two parallel integrity management approaches. The vast majority (over 90%) of ruptures caused by time-independent threats occur at the time that the activity takes place (*e.g.*, when the excavator hits the pipeline), and not at some later time. Therefore, the use of risk management practices (or technologies) to prevent damage or to immediately identify the potential for damage would be more effective than looking for evidence of past damage. Secondly, since some time-independent threats do not result in immediate

pipeline rupture, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely.

- Threats related to human error will be addressed largely, but not completely, through the new Operator Qualification Rule. The integrity management rule will require operators to evaluate the impact of operator error on the primary threats to pipeline integrity.

#### *Comments*

INGAA summarized the capability of pipeline in Classes 3 and 4 for using internal inspection tools as follows: 24.4% is easily piggable, 25.3% can be easily made piggable, 45.9% would be very costly to make piggable, and 4.4% cannot be pigged.

INGAA provided a set of examples of situations and conditions which may adversely impact the accuracy of results from the indirect processes used in external corrosion direct assessment. These include:

- Rocky backfill with little or no soil around the pipe.
- Very dry, cracked soil where little soil contact is made with the pipe.
- High-dielectric coatings (such as polyethylene tape) that have the propensity to shield the pipe from the flow of cathodic protection current, where no orifices to the soil/water interface are present.
- Resolution and sensitivity of survey equipment.
- Correct selection of the proper diagnostic tool matched to the suspected integrity threat.
- Bare or unprotected pipelines.

INGAA stated that data from the ongoing external corrosion direct assessment process development effort will need to be combined with data from application of the process over time to allow statistical analysis describing reasonable confidence bands.

A preliminary model was presented by INGAA that describes the use of the four step direct assessment process in assessing a pipeline for SCC. This description relies heavily on the assembly and integration of risk factor data that could indicate the possible presence of SCC. These risk factor data are presented in the appendix of ASME B31.8S.

AGA/APGA commented that not all pipelines should be required to be pressure tested for manufacturing or construction defects at sometime during their lifetime. For example, a pipeline should not require pressure testing if it has not experienced leaks during its lifetime. This argument assumes that