

piggable with extensive modifications, at a cost of between \$1M and \$8M per mile. APGA indicates that the comparable percentage of mileage for its members is 46% (~1,380 miles). Based on these industry-provided numbers, the cost of making the "very costly" lines piggable, excluding the increased cost of gas supply due to capacity restrictions, can be estimated to be between \$88B and \$710B. While these numbers are exceedingly large and rely on the AGA costs, developed for making difficult to pig lines piggable in urban areas, they do indicate that much work on existing lines would be needed to make all gas transmission lines piggable using today's ILI technology. INGAA also argues that pressure testing much of the currently non-piggable pipeline could be costly or impractical because of service interruptions needed to complete the hydro-test, and because the process introduces electrolytes into the system that will be difficult to completely remove, thereby increasing the likelihood for future internal corrosion.

In addition to the feasibility of ILI and the costs associated with making lines piggable, the cost to consumers and the potential of critical supply interruptions are other factors in the RSPA/OPS decision to allow direct assessment. The INGAA study, as mentioned previously, evaluated the cost to consumers associated with capacity restrictions resulting from gas pipe integrity assessment. This study evaluated capacity restrictions and related consumer cost impacts for integrity assessment scenarios involving different mixes of ILI, hydro-test and direct assessment technologies. For a baseline assessment time frame of ten years, the study determined that the difference in cost to the consumer (excluding the cost of making lines piggable) between conducting direct assessment on twenty-five percent and zero percent of piping would be over two billion dollars. Some supply interruptions could also result if direct assessment were not allowed as an alternative assessment technology.

What threats are direct assessment capable of characterizing? Work jointly funded by the gas pipeline industry and RSPA/OPS is ongoing to develop, validate and standardize the application of the direct assessment process to the assessment of external corrosion (ECDA) and internal corrosion (ICDA). Future work is planned to develop, validate and standardize a direct assessment process for application to the stress corrosion cracking (SCCDA) threat. Furthermore, significant anecdotal evidence exists that the ECDA process

may be capable of identifying coating damage associated with third party impacts on the pipeline, but formal validation of this capability has not yet been performed.

The current strategy, being incorporated in the developing consensus standard for external corrosion direct assessment for use with the ECDA process, is to locate areas suspected of having external corrosion by identifying defects in the pipe coating, then excavating those defects in areas where corrosion activity is suspected. While all indications discovered by ECDA that are not adequately protected by the cathodic protection system at the time of the assessment will be excavated and directly examined, only a fraction of the ECDA indications that are protected by cathodic protection systems at the time of the assessment will be excavated. This excavation strategy is incorporated in the draft NACE consensus standard on ECDA. The draft standard describes the process by which operators make decisions on the need for continued excavation of features in an ECDA region, based on the severity of defects revealed in previous excavations. If excavation of the indications that are expected to be most severe reveal no significant pipe damage, then further excavations in that region are not necessary. If excavation continues to reveal significant pipe damage, then a larger fraction of protected indications would be excavated.

An approach is under development by the Gas Technology Institute (GTI) for ultimate incorporation in a NACE consensus standard to locate internal corrosion (ICDA). The process, using direct assessment, is focused exclusively on pipe transporting nominally clean dry gas, in which moisture (electrolyte) has been introduced by abnormal operation. Further, it assumes that internal corrosion will only occur if moisture is present at the location in question. The Southwest Research Institute, under GTI funding, developed a mathematical model to predict locations where moisture would accumulate along the line, if it were introduced during an upset condition. These models, together with a common sense approach to identifying other pockets where moisture might accumulate, are to be used to identify areas where excavations and direct examination is required. While not yet validated, this approach is drawn from industry experience and is based on reasonable assumptions about the most likely location of internal corrosion.

There is a need for alternative assessment technologies capable of finding and characterizing pipe defects. RSPA/OPS decided to allow selective use of direct assessment for application in characterizing certain integrity-threatening defects in pipe that cannot (for economic or operational configuration) be pigged or hydro-tested. The conditions for use of direct assessment are based on draft NACE consensus standards with additional requirements that reflect the developmental nature of the processes.

Under What Conditions Can Direct Assessment Be Used?

The proposed rule proposes to allow an operator to use direct assessment as a supplement to the other allowable assessment methods, and to use direct assessment as a primary assessment method for external corrosion, internal corrosion, or stress corrosion cracking only when the operator can demonstrate that a specified condition exists. These conditions are when the other assessment methods cannot be applied to the pipeline segment for economic or technological reasons; the other assessment methods would result in a substantial impact on gas customers; excavation and direct examination will be done on the entire covered pipeline segment; or the covered pipeline segment operates at a maximum allowable operating pressure below 30% SMYS. To use direct assessment as a primary method for external corrosion, internal corrosion or stress corrosion cracking, the operator has to follow ASME/ANSI B31.8S and additional requirements set forth in the proposed rule.

In addition, to use direct assessment as the primary assessment method for third party damage, an operator has to show that no other assessment method is feasible, and that the operator will combine the method with data collection and integration to evaluate the segment's susceptibility to third party damage.

An operator choosing the external corrosion direct assessment (ECDA) method as its primary assessment technology must prepare a detailed plan in which the following information is documented:

- Data requirements for using ECDA; these must include as a minimum the data requirements specified in Appendix SP-A1 for external corrosion in ASME B31.8S.
 - Criteria for evaluating ECDA feasibility.
 - Criteria for defining ECDA Regions.
- Further discussion is presented later in this section.