

operation of the line is not subjected to pressure cycling of sufficient magnitude and frequency to produce growth of existing cracks. AGA/APGA does support existing requirements to pressure test all new pipelines before operation.

AGA/APGA commented that pipelines operating at hoop stress levels between 20% and 30% SMYS, where the failure mode is leakage not rupture, should be allowed to use assurance technologies, including mitigation

measures, other than pigging, pressure testing and direct assessment. An AGA paper, dated April 26, 2001, on "Integrity Management for Low Stress Pipelines" (copy filed in the Docket) further expands on these alternate technologies and mitigation measures.

AGA/APGA indicated that direct assessment is: (a) Currently being validated and imbedded in a NACE consensus standard; (b) being evaluated for application to bare pipelines; and (c)

should not be defined in an overly prescriptive manner.

AGA/APGA summarized the strengths and limitations of pressure testing and in-line inspection. They noted that all forms of integrity testing will have some impact on gas supply reliability, and that severe constraints or cut-off will be required with pressure testing.

The following table was developed by AGA/APGA on miles of member companies with various assessment capability.

Company membership	Miles in classes 3&4	Currently piggable (in percent)	Temp conversion for pigging (in percent)	Extensive retrofit for pigging <sup>1</sup> (in percent)	Cannot be pigged <sup>2</sup> (in percent)
AGA .....	13,500	12	10	43	35
APGA .....	3,000	13	.....	41	46

<sup>1</sup> Retrofit costs range from \$5,000 to \$250,000 per mile.

<sup>2</sup> Costs range estimated to be from \$1M to \$8M per mile to replace pipe (in urban areas).

The Florida Public Service Commission recommended that both magnetic flux leakage (MFL) pigging and pressure testing be carried out at intervals of five to seven years, not to exceed ten years. They also indicated that Florida gas pipes are typically less than twelve inches in diameter and therefore should be inspected at ten year intervals.

Pacific Gas & Electric Company (PG&E) also indicated that increased leak patrol frequency should be used to minimize the threat of leakage from pipe segments operating at low hoop stress (e.g., less than 30% SMYS).

PG&E commented that pipe segments operating at low stress levels should not be required to conduct a pressure test once in the pipeline life, but rather operating history should be used to validate material strength. They also noted they found direct assessment to be a good tool to identify residual third party damage.

PG&E noted that they do consider erosion to be one of the Outside Forces that needs to be considered, and they conduct annual erosion surveys to support mitigative action where erosion is identified.

PG&E summarized the reasons why some of its pipe is not piggable because of the presence of one or more of the following: telescopic construction, random diameter construction, sharp radius bends, and less than full opening valves.

NYGAS commented that local distribution company (LDC) transmission lines are typically sole source lines and are closely coupled to the distribution system. These facts will greatly increase the cost and impact on

customer supply of pigging and pressure testing.

NYGAS further commented, with supporting analysis from Kiefner and Associates, that under typical cyclic loading conditions, the fatigue life of a gas pipeline operating at stresses of 72% SMYS is 100 to 400 times longer than hazardous liquid pipelines, and that lowering the operating stress level to below 30% SMYS will increase this factor to between 900 and 3600.

Therefore, pressure testing at some time during the life of a low stress pipe should not be required. NYGAS also noted that experience has demonstrated ILI technologies do not perform satisfactorily at pressures below 400 psi.

NISource commented that it does not believe an integrity baseline needs to be established for all pipe segments. In particular, low stress pipelines have a "baseline" established through application of the existing regulations and monitoring for evidence of leaks. Current practices identify the physical conditions which increase the potential for gas accumulation resulting from a leak, and the presence of these conditions leads to increased monitoring.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful if the rule spelled out the process by which new assessment technologies would be approved by RSPA/OPS.

Several operators expressed concern about their ability to de-water a pipe segment that is not piggable following a pressure test. Inability to de-water would lead to increased likelihood of internal corrosion. This fact supports the advisability of allowing direct

assessment as an alternative assessment technology.

Comments from the public and the pipeline industry generally supported RSPA/OPS's approach in developing this proposed rule. The commenters generally agreed that the proposed rule should include: (1) A threat-by-threat analysis of each pipeline segment; (2) at least one pressure test during the life of a pipeline to characterize its susceptibility to material and construction defects, unless the operator can justify why a pressure test is not necessary; (3) periodic assessment of each pipeline segment for third party damage (denting), unless the operator can justify why such assessment is not necessary. A decision to forgo periodic assessment must address loading conditions (e.g., cyclic loading), pipe susceptibility to delayed failure (e.g., at Edison, NJ), and pipe exposure to potential third party damage; and (4) a description of how to apply direct assessment, including the conditions under which it is not appropriate, and conservative criteria for pipe excavation for direct examination.

#### *Baseline Assessment and Remediation*

The fourth element of integrity management discussed in the June 27, 2001 FR notice, related to the baseline assessment and remediation time frame. To determine time frames to conduct a baseline integrity assessment and to complete remediation following an assessment using an approach that prioritizes pipeline segments based on risk, we used the following hypotheses:

- The time frame for conducting the baseline assessment should be based on a graded or tiered approach where pipeline segments are prioritized for