

risk areas; and (6) determine the priority of each covered pipeline segment (*i.e.*, segments subject to the proposed rule that are within a potential impact zone are considered higher impact zones; those segments outside a PIZ are considered lower impact zones). Additional detail on identifying covered segments is provided elsewhere in this preamble and in the Definitions located at section 192.761 of the proposed rule.

Assessment Methods

There are four acceptable assessment methods defined by this rule. They are: (a) Internal inspection (also known as in-line inspection, ILI and pig testing); (b) pressure testing; (c) direct assessment, (a process that includes data gathering, indirect examination and/or analysis, direct examination, and post assessment evaluation); and (d) any other method that can provide an equivalent understanding of the condition of line pipe. In addition, the rule proposes a method known as confirmatory direct assessment that an operator could use as an interim reassessment method.

The Pipeline Safety Improvement Act of 2002 provides for assessment by "an alternative method that the Secretary determines would provide an equal or greater level of safety." Because the primary function of internal inspection tools or pressure testing is to determine the condition the pipe is in, we have determined that equivalent or greater safety can be provided by "other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe." We used this language in the liquid integrity management program rules and are proposing to include it under the list of allowable assessment methods for the baseline assessment and reassessments.

The rule proposes to allow direct assessment as a supplemental assessment method on any covered pipeline segment and as a primary assessment method on a covered pipeline where in-line inspection and pressure testing are not possible or economically feasible or where the pipeline operates at a low stress. None of the permitted assessment methods listed above is fully capable of characterizing all potential threats to pipeline integrity. Currently, direct assessment is only an acceptable inspection method for assessing external corrosion, internal corrosion and stress corrosion cracking. In addition, if no other assessment method is feasible, direct assessment may be used to evaluate third party damage. Operators choosing direct assessment technologies must undertake extra excavations and

direct examinations during the period while direct assessment is being validated.

Some additional details regarding direct assessment are highlighted here for the purpose of acquainting readers of this proposed rule with some of the basic principles associated with the use of direct assessment. First, for purposes of this rulemaking, above-ground inspection techniques (such as close interval surveys, direct current voltage gradient, and pipeline current mapper) are considered indirect examinations. Second, visual inspection, ultrasonic testing and x-ray examinations are considered direct examinations. Third, all three threats considered under direct assessment (external corrosion, internal corrosion, and stress corrosion cracking) are direct examination of pipe. Fourth, operators who assert that their pipelines cannot be internally inspected or pressure tested are required to include written justification in their plans explaining why their pipeline(s) cannot be tested using these methods. Fifth, operators who assert that internal inspection or pressure testing is not economically feasible will likewise be required to include written justification in their plans indicating why these methods are not economically feasible.

Another concept in the proposed rule is the use of Confirmatory Direct Assessment to evaluate a segment for the presence of corrosion and third party damage. This is a more streamlined assessment method that uses the steps involved in direct assessment to identify these significant threats to a pipeline's integrity. As discussed later in this document, RSPA/OPS is proposing that an operator use this method as an initial reassessment method within the required seven-year reassessment interval, if the operator has, within the proposed limits, established a longer reassessment interval for a particular segment. The follow up reassessment by pressure test, internal inspection or direct assessment would then be conducted at the established interval.

Additional information about direct assessment and confirmatory direct assessment is provided elsewhere in this preamble and at section 192.763(h) of the proposed rule.

Baseline Assessment Periods

Under this proposal, operators are required to complete a one-time baseline assessment on each covered segment. After a baseline assessment is completed on a segment, an operator will be required to reassess the covered pipeline segment at the specified interval. Operators using pressure

testing or internal inspection as an assessment method are required to complete the baseline assessment of a segment located in an HCA within 10 years of December 17, 2002 (the date the Pipeline Safety Improvement Act was signed into law). 50% of the covered segments would have to be assessed within five years. Operators using pressure testing or internal inspection as an assessment method are permitted 13 years to assess pipeline segments located in Class 3 and 4 locations where the area being assessed is not within the potential impact zone *i.e.*, the areas we are proposing to define as moderate risk areas. (Additional detail on potential impact zones is provided in the Definitions section (§ 192.761) of this proposed rule and in the guidance that follows the proposed rule text.) If direct assessment is used as an assessment method, the proposal is for the operator to complete the baseline assessment within seven years for segments located in HCAs, with 50% of the segments having to be assessed within four years. Ten years would be allowed for a pipeline segment located in a Class 3 or 4 location where the segment being assessed is not within the potential impact zone *i.e.*, is within a moderate risk area. Additional detail on baseline assessments is provided elsewhere in this preamble and at section 192.763(g) of the proposed rule. The timing of baseline assessments is covered in more detail at section 192.763(g)(4).

The Pipeline Safety Improvement Act of 2002 provides that a baseline assessment is to be completed "not later than 10 years after the date of enactment * * *" The Act further provides that at least 50% of covered facilities are to be assessed "not later than 5 years after such date * * *" Our proposal for baseline assessment using internal inspection, pressure test or equivalent technology is consistent with that requirement. We propose a shorter time frame for baseline assessment by direct assessment. The primary reason for proposing a shorter time frame is that direct assessment technologies are still under development and additional information needs to be gathered on their effectiveness. However, RSPA/OPS has been sponsoring research on direct assessment that should help expedite its validity as a method for assessment. Based on the results from this research OPS may be able to lengthen the time frame from five years to up to ten years.

Reassessment Intervals

The Pipeline Safety Improvement Act requires a minimum seven-year reassessment period. Thus, under the proposed rule we set a reassessment