

supported a ten-year DA interval on pipelines operating at less than 30% SMYS, which would be consistent with ASME/ANSI B31.8S. Semptra asserted that accelerating DA assessment schedules could result in assessment on some higher risk pipelines being deferred and suggested basing assessments on risk ranking of the various pipeline segments independent of the assessment method. The Association of Texas Intrastate Natural Gas Pipelines contended that Congress treated DA as equivalent to other methods of assessment and that RSPA cannot do differently. The Energy Association of Pennsylvania claimed the proposed seven-year interval is not consistent with the statute or Executive Order 13211, *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*.

In contrast, the New York Department of Public Service contended that extending the DA reassessment interval from five to ten years is unreasonable because external corrosion direct assessment is an immature process. New York asserted that although the ECDA process showed that the process was reliable in identifying locations of current or potential corrosion activity, more experience is needed to characterize uncertainties and increase confidence that serious anomalies will be detected.

With respect to the proposed CDA reassessment intervals, the State of New York asserted that CDA should not be considered a reliable assessment method and that full DA should be required every seven years. In contrast, Duke Energy opined that CDA should count as a valid reassessment and that a subsequent follow-up reassessment to CDA should not be scheduled for another seven years. Duke Energy recommended changing the rule to reflect that CDA is a valid reassessment technique on its own.

*Response:* Congress required “[a] baseline integrity assessment of each of the operator’s facilities in areas identified pursuant to subsection (a)(1) [i.e., high consequence areas],” and “periodic reassessment of the facility, at a minimum of once every 7 years” (49 U.S.C. 60109).

Industry commenters argued that this language can, and should, be read to require reassessments within seven years *after* the ten-year period in which baseline assessment of all covered segments had been completed. RSPA/OPS finds that the plain language of the statute precludes this interpretation. Industry suggests that the meaning of the word “facility” is key, and RSPA/

OPS agrees. Elsewhere in the section requiring baseline assessments within 10 years of enactment, the statute states, “At least 50 percent of such *facilities* shall be assessed not later than 5 years after such date of enactment. The operator shall prioritize such *facilities* for assessment based on all risk factors \* \* \*” (emphasis added). In contrast, the language requiring reassessment refers to periodic reassessment of the facility. Congress differentiated between individual pipeline segments and an operator’s entire pipeline system. The statutory language is clear that an assessment of each covered segment is required at least every seven years.

RSPA/OPS acknowledges that the requirements of the final rule will require that some reassessments be conducted before all baseline assessments have been completed. The rule has been written, however, in a manner intended to minimize the impact of this overlap to the extent practicable.

The rule allows different methods for reassessment, and the maximum reassessment interval depends on the method used and the operating pressure of the pipeline. However, the reassessment required at seven-year interval, the interval required by law, can be by Confirmatory Direct Assessment. CDA provides for much less potential disruption of pipeline operations than other assessment methods. No shut-down or curtailment of operation is needed to perform the indirect surveys that are a part of this method. Operators will likely reduce pressure when conducting excavations to protect personnel involved in that work, but the number of excavations required for CDA is less than for DA.

Reassessment intervals for DA have been revised to be the same as those required for other assessment methods. This reduces the amount of pipeline that must be assessed each year when compared to the five-year reassessment requirement in the proposed rule.

For pipelines operating below 30% SMYS, the final rule provides that the seven-year reassessment requirement can be met by a low-stress reassessment that includes indirect examinations, leak surveys, and other measures. The requirements for low-stress pipelines are discussed in item 7 of *Comments to NPRM*. This provision recognizes the relatively low risk posed by these pipelines and the likelihood that failures will result in leakage rather than rupture. Operators who implement this low-stress reassessment option also have the option of performing CDA. Reassessment for these low-pressure pipelines by the other methods allowed

by the rule (i.e., pressure test, internal inspection, direct assessment) are required only every 20 years, the maximum interval allowed by ASME/ANSI B31.8S.

*ERW Pipe.* Several comments concerned ERW pipe. The Gas Piping Technology Committee (GPTC) commented that the only way to assess seam issues is to conduct both an internal inspection and a pressure test, but such a requirement would not be practical. GPTC further commented that there are economic and technical barriers related to both Transverse Flux Inspection (TFI) and Ultrasonic tools. GPTC suggested the rule require that if an operator selects one of the multiple possible methods for assessment, it must consider the other method for reassessment. Semptra maintained the language on ERW pipe is unclear and that assessment should only be performed when a pipeline is subject to internal corrosion or when operating conditions could result in propagation of seam imperfections by fatigue.

*Response:* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe with a history of seam failure, an operator is required to select an assessment technology or technologies with a proven application capable of assessing seam integrity and of detecting seam corrosion anomalies. The operator is required to prioritize the covered segment as a high risk segment in its data integration and risk evaluation model.

*Training.* Duke Energy argued that the appropriate place for the training requirements is under the existing operator qualification requirements of Subpart N and not within the integrity management requirements. Oleska and Associates contended that the proposed training requirements for supervisors are too broad and that understanding should be commensurate with job responsibilities and relationship to the program.

*Response:* It is critical that personnel involved in integrity management programs and in conducting assessments have the appropriate training and qualifications for their functions. These functions are not, generally, within the scope of those covered by the Operator Qualification rule, because they are not tasks performed “on the pipeline.” In the final rule, RSPA/OPS has clarified the requirements for training, but continues to believe they are a necessary part of the rule.

*Other comments about program requirements.* We received a number of miscellaneous comments on some of the