

“microorganisms,” allowing the use of other measurement techniques that may be developed, referencing Graph E.III.1 when it is not a complete flow model, and replacing the word fluids with liquids, because gas is also a fluid.

Both Paiute Pipeline and Southwest Gas asserted that ASME/ANSI B31.8S should be exclusively referenced rather than writing a procedure for ICDA within Part 192. The Northeast Gas Association questioned the need to excavate additional locations if, upon excavation of the first location most likely to corrode, no internal corrosion was found.

NTSB commented that its investigation of the Carlsbad pipeline accident revealed areas where cleaning pigs had not been used that were likely locations for internal corrosion. NTSB suggested that RSPA/OPS highlight the increased corrosion potential of pipeline sections not subject to the periodic use of cleaning pigs.

Response: NACE is developing recommended practices for ICDA, but none has yet been finalized. Discussion of ICDA in ASME/ANSI B31.8S is limited, but the final rule does reference the requirements in Appendix B2 of that standard. The final rule includes basic requirements consistent with the recommended practices now under development. These recommended practices, when completed, will provide additional guidance for implementing these requirements. The requirements provide for a minimum of two excavations in each ICDA region. RSPA/OPS has concluded that more than one excavation is needed, because predicting the locations at which internal corrosion could occur is not an exact science. There are different types of locations in which such corrosion can occur. Multiple excavations, and direct examination of potentially affected pipe, are necessary to ensure that internal corrosion will be found.

RSPA/OPS has revised the language in the final rule to incorporate many of the suggested editorial comments. The final rule has also been revised to highlight the potential for increased corrosion of locations not subject to periodic use of cleaning pigs or in which cleaning pigs could deposit collected liquids.

Reassessment Intervals: RSPA/OPS proposed that the reassessment interval begin when the baseline assessment of a covered segment was completed. This had been proposed consistent with the statutory requirement in 49 U.S.C. 60109(c)(3)(A) that an integrity management program include “[a] baseline integrity assessment of each of the operator’s facilities * * *.” The

length of the proposed reassessment intervals depended on the assessment method, although some form of reassessment would have to be done by the seventh year of the interval. If an operator used pressure testing or internal inspection, the maximum reassessment interval proposed was ten years for a pipeline operating at or above 50% SMYS and 15 years if operating below 50% SMYS. If an operator established the maximum interval, the notice proposed that a Confirmatory Direct Assessment would have to be done in the seventh and fourteenth years. If an operator used DA, the notice proposed a five-year interval if examining and remediating defects by sampling, or ten years if directly examining and remediating all anomalies. Again, if the ten-year interval were established, the notice proposed a CDA be conducted by the seventh year.

In the NPRM, OPS requested comment on whether a rule should allow a maximum 20-year reassessment interval on pipelines operating at less than 30% SMYS, and reassessment by CDA method every seven years, without the need for reassessment by some other method, for pipelines operating below 20% SMYS (68 FR 4278, 4281). RSPA/OPS also sought comment on whether the rule should allow a maximum ten-year reassessment interval when DA is used on a pipeline operating at less than 30% SMYS.

Cook Inlet Keeper supported the proposal to reassess a covered segment every seven years, rather than to begin the reassessment interval only after the baseline assessment of all covered segments in a transmission system was complete. Cook Inlet maintained the proposal was consistent with the Congressional intent to ensure covered segments are reassessed every seven years. Cook Inlet argued that without such an interpretation, a segment assessed early during the baseline assessment period might be assessed late during the reassessment period, resulting in over 16 years between assessments.

Contrary to Cook Inlet’s position, the vast majority of commenters argued that reassessment intervals should begin after the initial ten-year baseline period, *i.e.*, the reassessment interval should not begin until all segments have been initially assessed. INGAA requested that the rule clarify that the initiation of the first reassessment is not mandatory until completion of the baseline period for the system. INGAA asserted that without this change, operators will be conducting reassessments on their systems in HCAs at the same time as

they are conducting baseline assessments, resulting in a potential for significant gas price spikes caused by outages on multiple pipeline systems occurring at the same time. INGAA claimed this would conflict with the intent of the legislation and preclude the ability to adjust priorities based on prior findings. Numerous commenters echoed INGAA’s comments.

Expanding on INGAA’s position, NiSource asserted that without the change, outages in overlap years are likely to make it difficult to refill storage during summer months and lead to shortages and price spikes the following winters. Kansas Gas Service maintained that if the overlap were not eliminated, a bubble of demand for assessment services much greater than any other year would be created during the overlap years and would not be sustained beyond the bubble, resulting in operators facing difficulty obtaining services and experiencing supply interruptions. PSNC Energy also recommended eliminating the overlap because it would cause economic and labor-related hardships and lead to shortcomings from cutbacks in remaining baseline assessments. Northeast Gas Association and several other commenters noted that the reassessment intervals should be the same as identified in ASME/ANSI B31.8S.

AGA proposed that the rule incorporate the maximum interval set for pipelines operating below 30% SMYS in the ASME/ANSI B31.8 standard, with interim preventive and mitigative measure being applied every seven years. Ten commenters, including Vectren, Dominion, and Northeast Gas Association, supported AGA’s proposal that the rule allow a maximum 20-year reassessment period for pipelines operating under 30% SMYS. Northeast Gas Association also recommended the 20-year interval also apply for Direct Assessment. Sempra, the Iowa Utilities Board, and other commenters supported less stringent requirements for pipelines operating below 30% SMYS because of the lesser hazard posed by failure of these low-stress pipelines.

There were many comments on the proposed shorter reassessment intervals for operators using Direct Assessment. American Public Gas Association, American Gas Association, and several other commenters argued that DA reassessment intervals should be the same as for other methods. Williams Gas Pipeline maintained that having shorter DA intervals is not justified and Panhandle Eastern suggested that the reassessment intervals should be based on ASME/ANSI B31.8S. PG&E