

We indicated above that assessing pipelines using any of the technologies under consideration may result in a restricted gas supply because of the need to take pipelines out of service or by reduction in throughput. In addition, some types of repairs will also require lines to be taken out of service. If an upstream segment of this gas transmission pipeline were put out of service temporarily for test or repair, many communities located at the end of branch lines, could be negatively impacted by the restricted gas supply. This effect would be caused by the fact that the lines are often sole source feed, (i.e., have no other tie-in's from an alternative source.) Because of this factor, the proposed rule allows a waiver of a reassessment interval greater than seven years, if the operator demonstrates that it cannot maintain local product supply, and OPS determines that a waiver would not be inconsistent with pipeline safety. This proposal is consistent with the provision in the Pipeline Safety Improvement Act of 2002. Because a waiver requires public notice and comment, we are proposing 180-day advance notification.

INGAA Report

INGAA commissioned an extensive analysis of the economic impact of a gas IMP rule. The analysis, performed by Energy & Environment Analysis, Inc., evaluated this impact using various assumptions on the fraction of the affected pipe that is currently not piggable that will be assessed by pigging, pressure testing, or direct assessment. The time frame during which the baseline assessment must be performed was also a parameter in the analysis, varying from five to fifteen years. While (at the time of the INGAA comment—August 14, 2001) sufficient detail was not available to evaluate the credibility of the analysis and its underlying assumptions, the estimated economic impact on gas consumers for the ten year baseline period is large, ranging from \$3.9 billion to \$6.1 billion. (Note, this analysis and a peer review of report performed by the Volpe National Transportation Systems Center (Volpe Center) and the Department of Energy (DOE) have recently been completed and are discussed below).

AGA/APGA commented that some forms of assessment (e.g., pressure testing) would require outages from 3 to 9 days. Customers would in some cases be without gas during that time, and restoration of gas supply would require extensive work, for example, re-lighting pilot lights of each affected customer.

Discussions on the INGAA Report on "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas" (February 2, 2002)

On April 3, 2002, RSPA/OPS held a meeting with INGAA, Energy and Environment Associates (EEA), the Volpe Center, and DOE to discuss the INGAA report on "Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas" (February 2, 2002). The meeting was designed to allow RSPA/OPS, and several reviewers retained by RSPA/OPS, to explore the reasonableness of the results in the INGAA-sponsored report. The focus of discussion was on the assumptions made in the analysis. The report was produced in response to the initial need to understand the supply and economic implications of allowing or disallowing direct assessment as a primary assessment technology, and later was expanded to evaluate the supply and economic implications of various baseline assessment intervals ranging from 5 to 15 years.

The report focuses on interstate transmission pipelines. INGAA indicated the industry expects that most HCA mileage will lie in Class 3 and 4 Locations, and that approximately 5% of pipeline is in class 3 and 4 locations, but that the HCA definition will include some pipe segments in other locations as well. INGAA said that Class 3 and 4 Locations are scattered throughout the pipeline system so they appear in about 60% of valve stations and 80% of the discharges from compressor locations.

INGAA further stated that a periodic inspection program was useful only to identify the presence of dynamic failure mechanisms or threats (i.e., corrosion). They questioned the value of periodic assessment of pipelines for static threats (i.e., material and construction) or random threats (e.g., third-party damage).

The reviewers at the meeting requested clarification of the study assumption regarding the fraction of lines that are assumed to be in-line-inspected. Scenarios 1, 2 and 3 in the report assume segments described as "currently piggable" and "relatively easy to make piggable" are treated as "easy to pig" (i.e., about 50%). The other scenarios, 3A, 3B and 3C in the report assume that only "currently piggable" segments are treated as "easy to pig" (i.e., about 25%). This difference in assumptions complicates comparison between Scenarios 1, 2 & 3 and Scenarios 3A, 3B & 3C. EEA stated that market evaluations do show that there are capacity choke points and that spot market prices respond to capacity

restrictions. Examples include recent price spikes in the States of California and New York. These capacity restriction effects were the focus of the study. No account was taken of the cost incurred by operators making lines piggable, although the capacity impacts associated with these maintenance activities were considered.

Other key assumptions in the analysis include: (1) 80% of mainline pipe and 50% of laterals/connections will be inspected (these numbers are supported by consideration of the distribution of segments that can affect HCAs throughout the pipeline systems and by the fact that even operators using direct assessment as their primary assessment approach will be required to reduce pressure in long segments of their lines during the direct examination step of the process). (2) Effects on consumers with limited options and flexibility in gas providers will be much more severe (e.g., Florida has one transmission line, with a second to come in service this summer. Load factor on the line is greater than 80% and any interruptions would have significant downstream effect, and therefore cost impacts). It was noted by INGAA at the meeting that gas supply interruptions are not as routinely buffered by storage capacity as liquid petroleum products, which are normally stored in tanks. (3) The industrial sector is more elastic than the residential sector. Demand there was adjusted significantly when gas prices were high over the last couple years. (4) The analysis assumes that the impact of supply restrictions occurs at the time the restriction occurs rather than at a later time, as would occur because of long-term supply contracts. (5) Both pipeline capacity and demand are assumed to increase, as described in the base case of "The Pipeline and Storage Infrastructure for a 30 Trillion Cubic Feet (TCF) Market" better known as the "30 TCF study."

The TCF study uses the EEA Gas Market Data and Forecasting System. This model was developed in 1995 requiring over ten person years of effort. The model is rigorously calibrated to actual historical behavior. Price differences are calculated as a function of load factor. The calibration is updated annually.

The model is a fairly coarse one in which multiple supply lines between market centers are modeled as a single line. However, the model appropriately considers the effects of capacity restrictions in one line in a corridor, and does not assume that a single line out of service terminates supply through the corridor in which it resides. This effect is treated separately from the model and