U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

JUN 26 2006

Mr. Jerry Milhorn
Vice President of Operations
Kinder Morgan Energy Partners, L.P.
500 Dallas Street, Suite 1000
Houston, TX 77002

Re: CPF No. 1-2004-5004

Dear Mr. Milhorn:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It makes findings of violation, assesses a civil penalty of $325,000, and specifies actions to be taken to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty is paid and the terms of the Compliance Order are completed, as determined by the Director, Eastern Region, this enforcement action will be closed. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: William Gute, Director, Eastern Region

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	
Kinder Morgan Energy Partners, L.P.,	**CPF No. 1-2004-5004**
Respondent	

FINAL ORDER

During the weeks of April 7, April 21, and June 23, 2003, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety (OPS) conducted an inspection of Respondent's integrity management program at its facilities in Orange. California and Doraville, Georgia. As a result of the inspection, the Director, Eastern Region, OPS, issued to Respondent, by letter dated July 15, 2004, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had committed violations of 49 C.F.R. Part 195, and proposed assessing a civil penalty of $325,000 for the alleged violations. The Notice also proposed ordering Respondent to take certain measures to correct the alleged violations.

Respondent responded to the Notice by letter dated August 16, 2004 (Response). Respondent contested many of the allegations in the Notice and requested a hearing. The hearing was held on April 12-13, 2005 in Washington, DC. After this hearing, Respondent provided additional information for the record on May 12, 2005.

FINDINGS OF VIOLATION

Item 1 in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(b)(3) by failing to include provisions in its baseline assessment plan (BAP) to account for and address the susceptibility of its pre-1970 low-frequency ERW piping to seam failures and the potential of its piping for stress corrosion cracking (SCC) in the absence of sound technical justifications for discounting these risk factors. The integrity management program (IMP) regulations require pipeline operators to identify and assess the risks associated with operating their pipelines that, in the event of a failure, could affect a high consequence area (HCA). In order to conduct a meaningful risk analysis, a pipeline operator must accurately represent all of the risks on a given pipeline in its chosen risk model including assigning the appropriate weight to each risk factor relative to other risk factors so that the pipeline segments that pose the highest risk to HCAs can be appropriately prioritized.

With respect to the ERW pipe issue, it has been commonly known throughout the pipeline industry for many years that pipelines constructed before 1970 using low-frequency ERW longitudinal seams and lap welded pipe are susceptible to seam failures.[1] Based on historical performance, ERW and lap-welded pipe is susceptible to seam failure and presents a higher risk of failure than other pipe, all other factors being equal. Moreover, the pipeline safety regulations expressly deem all pre-1970 ERW pipe to be presumptively susceptible to seam failure.[2] Therefore, the presence of pre-1970 ERW pipe is a significant risk factor and seam failure is a failure mode that operators of ERW pipe must fully address in their risk analyses. In this case, seam failures on some of the actual ERW pipe in Respondent's Santa Fe Pacific Pipeline (SFPP) were documented in OPS Technical Report 89-1.[3]

In its response and at the hearing, Respondent acknowledged that the susceptibility of pre-1970 low frequency ERW pipe to seam failures was known industry-wide as a significant risk. Respondent, however, contested the allegation that it failed to adequately address the presence of ERW pipe in its pipeline system in its IMP plan. In connection with the hearing, Respondent produced a memorandum that purported to establish that it had replaced the ERW pipe it believed to be susceptible to seam failure.[4] The memorandum noted that "about a mile of the Richmond-Oakland 8-inch immediately downstream of Richmond Station and about 3.5 miles of the 10-inch San Diego Line through Tustin" had been replaced. Notably, however, the study did not document why only those small sections of ERW pipe were deemed to be high risk and the rest of the ERW pipe in its system was not. Respondent also asserted that all of the remaining ERW pipe in its SFPP was subject to operating restrictions. OPS correctly pointed out, however, that while the SFPP is a significant part of the Respondent's system, it only represents about 25 percent of the total mileage of Respondent's pipeline system to which its IMP applies. The assessment of pipelines that are susceptible to seam failures that could affect a HCA is a requirement for all such pipelines. Respondent made no assertion that similar reviews had been conducted for its other pipelines.

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[1] OPS issued Alert Notices on January 28, 1988 and March 8, 1989 informing pipeline operators that low-frequency ERW pipe was subject to longitudinal weld seam failures caused by the presence of manufacturing defects in the ERW seams that can grow over time. Seam corrosion and cyclic fatigue have been found to have contributed to the growth of these defects and in some cases, operational failures have occurred many months or years after successful hydrostatic testing was conducted. This is also reflected in subsequent rules. For example, the preamble that accompanied publication of the rule establishing a risk-based alternative to pressure testing, as follows: "Pre-1970 electric resistance welded (ERW) and lap welded pipelines susceptible to longitudinal seam failures exhibit the highest potential risk because of their combination of probability of failure and potential for larger volume releases as evidenced by historical records" (63 FR 59475, Nov 4, 1998).

[2] 49 C.F.R. § 195.303(d).

[3] "ERW Summary for Liquid and Gas Transmission Lines." (1989). At the time, this pipeline was known as the Southern Pacific Pipeline.

[4] During the 2003 inspection, Respondent apparently did not present the SFPP study. The memorandum provided by Respondent describing the study made the following single qualitative generalization: "a large portion of the pipe purchased by SPPL in the mid to late 1960's was manufactured at Kaiser's Fontana mill using modern techniques and is of good quality." (Letter from Engelhardt to DesBarres, Sept. 8, 1989).

Respondent also asserted that its subject matter experts (SMEs) had concluded that its pipe was not susceptible to seam failure. At the time of the inspection, however, Respondent presented no seam analysis or other documentation demonstrating that a thorough engineering or metallurgical analysis on the susceptibility of its ERW pipe to seam failures had been conducted. Moreover, at the time of the inspection, Respondent's "Bass Trigon" computer risk model reflected Respondent's apparent lack of information about the type of longitudinal seam for many segments of its pipeline system. The data used for the seam type for a significant number of pipeline segments in the risk model were listed as "unknown."

Respondent also argued that there was a lack of industry guidance for how to perform an engineering analysis to determine the susceptibility of particular ERW pipe to seam failures. OPS, however, pointed out that guidance was available for performing ERW analysis. To take just one example, Dr. John Kiefner published a methodology for conducting such an analysis in a paper presented on February 2-6, 2002 at the ASME Engineering Technology Conference on Energy, entitled "Dealing With Low-Frequency-Welded ERW Pipe and Flashwelded Pipe With Respect To HCA-Related Integrity Assessments." While pipeline operators are not required to follow Dr. Kiefner's methodology, the availability of his methodology is sufficient to establish that industry guidance for conducting an engineering analysis to determine the susceptibility of ERW pipe to seam failure was available to Respondent in advance of the inspection.[5]

Respondent further asserted that in-line electromagnetic acoustic transducer (EMAT) inspection tools capable of detecting seam defects were only just becoming commercially available at the time of the inspection. This assertion, however, is not relevant to the merits of the allegation. Respondent was cited for failing to identify which of its lines are susceptible to seam failure and to schedule an assessment for those lines. Even if the EMAT technology was not available at the time, other methods were available by which to conduct integrity assessments for seam defects including hydrostatic pressure test, ultrasonic in-line crack detection tools, and transverse flux magnetic flux leakage in-line crack detection tools. Respondent was aware of other technologies available for conducting assessments for cracks and seam defects.

Finally, we note that one of the key technical factors in determining susceptibility to seam failure is the degree of cyclic loading experienced by a given line. Pressure cycling promotes defect growth and can contribute to eventual failure. Respondent, like many other hazardous liquid pipeline operators, performs batch operations on its mainlines and delivery lines which typically generates frequent pressure cycling. Absent a strong technical justification to the contrary, any ERW line operated under these circumstances should be considered susceptible to seam failure, and assessment methods must be selected accordingly. In a system of approximately 10,000 miles of pipelines, composed of numerous older legacy systems subject to frequent pressure cycling, Respondent's claim that it had no segments considered susceptible to seam failure was unpersuasive. Overall, Respondent failed to demonstrate that its decision to exclude the

[5] Respondent stated that it subsequently adopted an updated procedure based on the Baker study entitled "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation Final Report" (Oct. 2003), and Respondent emphasized that this report was issued after the OPS inspection. The Baker study, however, was conducted in association with Dr. Kiefner, and the susceptibility analysis described in the Baker study is only a slightly updated version of the analysis methodology Dr. Kiefer presented to ASME in February 2002, as discussed above.

susceptibility of its ERW pipe to seam failures as a significant factor in its risk analysis was justified by sound technical analysis during the relevant time period.

With respect to stress corrosion cracking (SCC), Respondent acknowledged that SCC was a risk on pipelines, but argued that because it had never experienced a "known" SCC failure prior to the inspection it was justified in discounting SCC as a significant factor in its risk model. OPS pointed out that prior to the mid-1990s, Respondent had been to some degree ineffective in its determination of the causes of pipeline accidents to the point that OPS had cited and levied a civil penalty and compliance order against Respondent in 1994—in part for its failure to ascertain the causes of pipeline accidents. Therefore, it is possible that past accidents could have been caused by SCC, but were undiagnosed because there is reason to believe that Respondent did not effectively determine the true cause of many historical accidents. In addition, Respondent built its extensive network of pipelines through acquisitions. In order for Respondent to defend this assertion, it would have needed to present a rigorous review of the historical pipeline accidents on its legacy systems that occurred during previous ownership. Therefore, while Respondent may not have previously *attributed* a pipeline failure to SCC, this is not the same thing as saying Respondent had no reason to consider SCC to be a potential risk factor. Absent metallurgical reports on all past failures, Respondent's statement that its systems have never experienced a SCC-related failure is inconclusive at best.

Respondent also argued that it did not believe that the IMP rule contemplated the consideration of SCC as a threat to hazardous liquid pipelines at all. This argument, however, is unpersuasive. Published guidance for implementation of the rule in Appendix C to 49 C.F.R. Part 195 explicitly lists SCC as a threat to be assessed with crack detection in-line inspection (ILI) tools. In addition, the preamble to the IMP rule (65 FR 75396) specifically addresses crack detection and SCC in the BAP as follows:

> *What Must Be in the Baseline Assessment Plan? Section 195.452(c)*
>
> ...
>
> *Crack Detection: Since the early 1990's, pipeline operators have successfully field tested internal inspection tools capable of nondestructively identifying fatigue cracks and <u>stress corrosion cracking</u> in the longitudinal seam. Research and development continues on these tools to strive for reliable identification of other types of seam defects, such as hook cracks. With the use of ultrasonic and MFL (transverse orientation) technology, pipeline segments that have experienced fatigue cracking can now be inspected. Cracks with a potential to rupture can be identified and repaired prior to growing to a critical stage. This is particularly important as this type of defect could survive initial and subsequent pressure tests but then with pressure cycling, grow over time to a critical stage and leak or rupture [emphasis added].*

This put pipeline operators on notice that the intent of the rule language requiring operators to develop and follow IMP plans was for BAPs to include assessments to address the risks of crack defects—including SCC because of its particular importance. Finally, Respondent cited OPS Advisory Bulletin ADB 03-05 in an attempt to justify its assertion that the rule did not contemplate consideration of the SCC threat. It is clear from the text of the IMP rule, however, that the rule did not specifically focus on any particular threat because it was intended that operators address *all* threats. Therefore, while Respondent correctly points out that this advisory bulletin was not issued until after the inspection, it merely notes that the rule did not specify SCC.

Respondent also suggested that there was no technical guidance in place at the time of the inspection for industry or OPS inspectors to use in evaluating SCC threats. OPS, however, pointed out that numerous reference and research reports pertaining to SCC threats to pipelines had been published by the time Respondent was developing its BAP. The Baker Report, for example, compiled many references to SCC dating back to the 1970's. [6] Some of the more important reports highlighted by Baker include:

- "Report of the Inquiry [on] Stress Corrosion Cracking on Canadian Oil and Gas Pipelines" by the Canadian National Energy Board (NEB 1996).
- "Stress Corrosion Cracking–Recommended Practices" published by the Canadian Energy Pipeline Association (CEPA 1997a). Baker noted that "[t]he document presents an excellent model for pipeline operators who are setting up procedures for preventing, controlling and mitigating external SCC."
- CEPA produced an additional report that specifically addresses circumferential SCC, a less common form of SCC (CEPA 1997b). This report documents the experiences of NOVA Gas Transmission Ltd., Northwestern Limited, Federated Pipe Lines Ltd., and the SNAM system in Italy in investigating and mitigating leaks due to circumferential SCC. Subsequently, CEPA issued an addendum to the Stress Corrosion Cracking—Recommended Practices addressing circumferential SCC (CEPA 1998).
- "Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking on Gas Pipelines", Eiber and Leis (1998). In this report, Eiber and Leis document the development of a simple form for evaluating the susceptibility of a pipeline segment to high pH SCC. An example of an SCC integrity management plan is also presented. This document provides good descriptions of the variables that are considered for determining the degree of susceptibility of a pipeline to high pH SCC and presents summary level supporting historical data.

Therefore, Respondent's suggestion that there was no guidance available to industry by which to evaluate, assess, and manage the threat of SCC is unfounded.

Respondent then argued that its IMP did address SCC because one paragraph in Section F3.5 referenced SCC. Although Respondent's program description demonstrates that it was aware of the factors that influence SCC risk as reflected in API-1160, compliance with the rule requires more than a brief description of what should be done. The IMP rule requires that operators implement and follow the program elements at each stage. Simply put, Respondent did not

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[6] "Stress Corrosion Cracking Study with Database, Final Report," Michael Baker Jr., Inc. (Jan. 2005). While the Baker report did not preceed the inspection, it did not document any new technical research, or develop any new guidance for handling SCC. Rather, the Baker report was a compendium and summary of existing research and guidance already available to industry assembled into one convenient source.

analyze for SCC in prioritizing its segments for baseline assessments. To the contrary, it decided to turn off the following known risk factors for SCC in its computer risk model: age of pipe; type of coating; CP system conditions and levels; soil stresses; drainage type: degree of pressure cycling; excavation data; and fracture mechanics analysis.

Respondent further asserted that its program was literally identical to API-1160. As a factual matter this is incorrect. For example, the only basis offered by Respondent for turning off the SCC risk factor was a lack of known failures—but failure history is not listed in API-1160 as a consideration when analyzing SCC risk attributes. API-1160 includes a number of guidance statements on SCC including:

- API-1160 indicates that SCC inspections should only be suspended or postponed after two consecutive assessments in which no new SCC sites were discovered (Section 9.4.2). This guideline was not in Respondent's program (indeed they did not include any SCC assessments in their plan as of March 2003).
- API-1160 identifies continued hydrostatic testing to account for crack growth, including SCC specifically (Section 9.5.2). This guideline was not reflected in Respondent's program.
- API-1160 cautions that SCC may be present for many years before causing problems (Section A.1.6.3). This is why past failure history alone is not a good enough indicator of SCC risk to be the sole reason for discounting it.

None of these guidelines were reflected in Respondent's BAP. Therefore, Respondent's written program was not identical to API-1160, much less implemented in accordance with the standard. In fact, as noted above Respondent decided to turn off every risk factor in Respondent's Section F3.5 that corresponded to API-1160 in its risk analysis computer model. Finally, it should be noted that API-1160, Section 8.4, "Characteristics of a Sound Risk Assessment Approach" explicitly states that:

> *"A risk assessment should be investigative in nature, seeking to identify previously unrecognized threats to pipeline integrity. It should make use of previous events, but focus on the potential for future mishaps, including scenarios that may never have happened before."*

The IMP rule requires pipeline operators to follow recognized industry practices in carrying out their IMP programs unless the operator can demonstrate that an alternative practice is supported by a reliable engineering evaluation.[7] Respondent's approach reflected a reluctance to take an investigative approach to the identification of threats in order to avert pipeline accidents, including those caused by previously unrecognized threats to the pipeline.

Accordingly, I find that Respondent violated § 195.452(b)(3) by failing to include provisions in its BAP to account for and address the susceptibility of its pre-1970 low-frequency ERW piping

[7] 49 C.F.R. § 195.452(b)(6). While API-1160 was not formally incorporated by reference into 49 CFR Part 195 at the time the IMP rule was issued, it still serves as evidence of the generally accepted industry practice for pipeline integrity management programs.

to seam failures and the potential of its piping for SCC in the absence of sound technical justifications to discount these risk factors.

Item 2a in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(e)(1)(i) by failing to consider the results of previous integrity assessments including previously identified defect type and predicted growth rate in establishing an integrity assessment schedule prioritizing its pipeline segments by risk. Section 195.452(e) requires a pipeline operator to base its assessment schedule on all risk factors that reflect the risk conditions on each segment and list several such factors including previous integrity assessments.

In its response and at the hearing, Respondent acknowledged that it decided not to activate the capability of its computer model to analyze previous integrity assessments, but contended that it used qualitative evaluation by its SMEs to evaluate those risk factors that it chose to turn off in the computer model. After Respondent made this argument, OPS pointed out that Respondent's risk ranking exactly matched the ranking produced by the computer model alone. OPS further noted that because the omitted risk factors were of such importance, it is implausible that any thorough SME analysis of these omitted factors would have zero influence on the resulting risk ranking. Moreover, the number of data elements listed in the matrices in Respondent's own exhibits that its SME's would have had to collect and analyze for a 10,000 mile pipeline system would have taken a significant period of time to conduct systematically and thoroughly and would have generated large volumes of decision making information and technical analysis documentation that Respondent would have been required by regulation to maintain.[8] Respondent did not present any such documentation. Therefore, even if Respondent's SMEs contributed to the process to one extent or another, Respondent failed to demonstrate that the resulting risk analysis considered previous integrity assessments in a manner that permitted a meaningful risk ranking. Accordingly, I find that Respondent violated § 195.452(e)(1)(i) by failing to consider the results of previous integrity assessments including previously identified defect type and predicted growth rate in establishing its integrity assessment schedule.

Item 2b in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(e)(1)(iii) by failing to consider repair history in establishing an integrity assessment schedule prioritizing its pipeline segments by risk. Respondent offered the same response to this item as for Item 2a above. For reasons already discussed, Respondent was unable to refute the allegation. Accordingly, I find that Respondent violated § 195.452(e)(1)(iii) by failing to consider repair history in establishing its integrity assessment schedule.

Item 2c in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(e)(1)(vii) by failing to consider local environmental factors, including soil corrosivity, subsidence, climactic conditions, and geo-technical hazards, in establishing an integrity assessment schedule prioritizing its pipeline segments by risk. Respondent offered the same response to this item as for Item 2a above. For reasons already discussed, Respondent was unable to refute the allegation. Accordingly, I find that Respondent violated § 195.452(e)(1)(vii) by failing to consider local environmental factors including soil corrosivity, subsidence, climactic conditions, and geo-technical hazards in establishing its integrity assessment schedule.

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[8] 49 C.F.R. § 195.452(l).

Item 2d in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(e)(1)(ix) by failing to consider physical support of a segment such as by a cable suspension bridge in establishing an integrity assessment schedule prioritizing its pipeline segments by risk. Respondent offered the same response to this item as for Item 2a above. For reasons already discussed, Respondent was unable to refute the allegation. For reasons already discussed, this argument was unpersuasive. Accordingly, I find that Respondent violated § 195.452(e)(1)(ix) by failing to consider physical support of a segment such as by a cable suspension bridge in establishing its integrity assessment schedule.

Item 3a in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(i)(2) by failing to maintain documentation demonstrating that the risk model it used to identify the need for preventative and mitigative measures to protect the HCAs weighted and scored all of the relevant risk factors in a manner permitting a meaningful risk analysis of its system. Respondent did not contest this allegation. Accordingly, I find that Respondent violated § 195.452(i)(2), as more fully described in the Notice.

Item 3b in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(i)(2) by failing to demonstrate that weight assigned to product type by the risk model it used to identify the need for preventative and mitigative measures was justified given Respondent's actual operating experience. Specifically, the Notice alleged that in some cases product type was weighted as much as 2:1 versus all other risk factors combined. OPS contended that because product type is most strongly associated with internal corrosion risk, Respondent's decision to assign this level of weight to product type distorted its risk analysis by overwhelming the risk weighting for other risk factors actually identified as the cause of historical failures on Respondent's system, such as factors associated with external corrosion, third-party damage, or seam failures.

In its response and at the hearing, Respondent insisted that the weight it assigned to product type was appropriate. OPS, however, showed that over the period from 1998 to 2003, while Respondent's pipelines experienced a number of failures, in no instance was the primary cause determined to be internal corrosion. The integrity management regulations do not prescribe the weight to be assigned to any single risk factor. A pipeline operator, however, is obligated to weigh all of the relevant risk factors in a manner permitting a meaningful risk analysis of its particular system. Respondent failed to demonstrate that the weight it decided to assign to product type permitted a meaningful risk analysis given the historical causes of failures that actually occurred on its system. Accordingly, I find that Respondent violated § 195.452(i)(2) by failing to demonstrate that the weight assigned to product type by the risk model it used to identify the need for preventative and mitigative measures was justified given Respondent's actual operating experience.

Item 3c in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(i)(2) by failing to demonstrate that the weights assigned to the HCA risk factors by the risk model it used to identify the need for preventative and mitigative measures was based on the relative risk relationships among those factors. Respondent did not contest this allegation. Accordingly, I find that Respondent violated § 195.452(i)(2), as more fully described in the Notice.

Item 3d in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(i)(2) by failing to demonstrate that the weight assigned to segment length by the risk model it used to identify the need for preventative and mitigative measures was justified given Respondent's actual operating experience. Specifically, the Notice alleged that, with respect to the 212 ranked segments for the Western/Midcon area, the average length of the 25 highest ranked segments was 1.54 miles while the average length of the 25 lowest ranked segments was 54.97 miles and that nothing in Respondent's operating history supported this scoring method.

In its response and at the hearing, Respondent insisted that the weight it assigned to segment length was appropriate. OPS acknowledged that shorter lines can be in more populated areas, but pointed out that longer lines affect many HCAs where shorter lines affect few of them. Moreover, Respondent was unable to establish as a factual matter that its spill history supported its assertion that the shorter segments were at higher risk of failure. The integrity management regulations do not prescribe the weight to be assigned to any single risk factor. A pipeline operator, however, is obligated to weigh all of the relevant risk factors in a manner permitting a meaningful risk analysis of its particular system. Respondent failed to demonstrate that the weight it decided to assign to segment length permitted a meaningful risk analysis given the history of spills that actually occurred on its system. Accordingly, I find that Respondent violated § 195.452(i)(2) by failing to demonstrate that the weight assigned to segment length by the risk model it used to identify the need for preventative and mitigative measures was justified given Respondent's actual operating experience.

Item 4 in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(f)(3) by failing to integrate available information concerning the age of in-line inspections and hydrostatic pressure tests into its integrity management analysis. In its response and at the hearing, Respondent acknowledged that its analysis did not differentiate prior assessments by age but argued that the integrity management regulations were "silent" on whether differentiation of prior assessments by age was required. This argument, however, is unpersuasive. The integrity management regulations expressly require that operators consider the results of previous integrity assessments such as defect type and size, and defect growth rate. It appears that for a system as large as Respondent's, OPS was willing to allow the age of previous assessments to serve as a kind of proxy for the true conditions of each pipeline (based on the presumption that all previous assessments resulted in the identification and repair of all significant pipeline defects identified). Pipelines recently assessed could therefore be presumed to be in relatively sound condition. However, for older assessments, there is less assurance that the line remains in sound condition. Scoring all lines that had ever been assessed equally does not acknowledge the reality that lines that have not been assessed in a long time are much more likely to have integrity-threatening defects than lines which were assessed and repaired recently. Because Respondent only considered whether it had or had not conducted an assessment but failed to consider the results of the previous assessments, the actual condition of the line discovered during the previous assessment was not captured. Respondent not only failed to analyze the results of past assessments as required by the rule, but did not even use age differentiation to approximate this required risk factor in its analysis.

Respondent also suggested that no guidance on this issue was made available. However, Appendix C to 49 C.F.R. Part 195 specifically guides the operator to consider "Date of pig run" in one of the hypothetical models. Moreover, as was noted previously the IMP rule directs operators to follow recognized industry practices in carrying out the integrity management requirements.[9] API 1160 Section 8.8 stresses the importance of incorporating the results of previous integrity assessments into the "likelihood of failure" estimation. Accordingly, I find that Respondent violated § 195.452(f)(3) by failing to integrate available information concerning the age of previously conducted assessments into its integrity management analysis.

Item 5 in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(g) by failing to use available pipeline data as inputs in its information analysis including basic information on seam design, block valve rating, maximum expected discharge pressure, and internal corrosion inhibitor. At the hearing, Respondent acknowledged that the integrity management program documentation provided to OPS at the time of the inspection did not demonstrate that the specified data sets were reflected in its integrity management program. Respondent did provide additional data tabulation materials in connection with the hearing reflecting modifications that were subsequently made to its program, but this material was for a different set of line segments and Respondent was unable to establish that this material represented the data tabulation practices Respondent had in place at the time of the inspection.[10] Therefore, Respondent failed to demonstrate that it considered the results of previous integrity assessments in a manner permitting a meaningful risk analysis during the relevant time period. Accordingly, I find that Respondent violated § 195.452(g) by failing to use available pipeline data as inputs in its information analysis.

Item 6 in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(e)(1)(iv) by failing to include eleven specified HCA line sections containing hazardous liquids in its BAP. Respondent did not contest this allegation. Accordingly, I find that Respondent violated § 195.452(e)(1)(iv) as more fully described in the Notice.

Item 7 in the Notice alleged that Respondent violated 49 C.F.R. § 195.452(d)(3)(ii) by failing to incorporate new HCAs or new information about existing HCAs into its BAP within one year from the date the areas were identified. Respondent did not contest this allegation. Accordingly, I find that Respondent violated § 195.452(d)(3)(ii) as more fully described in the Notice.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

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[9] See footnote 7.

[10] We make no determination here as to whether these additional documents were sufficient to subsequently establish compliance.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $100,000 per violation for each day of the violation up to a maximum of $1,000,000 for a related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require.

With respect to Item 1, the Notice proposed a civil penalty of $100,000 for Respondent's failure to include provisions in its BAP to account for and address the susceptibility of its pre-1970 low-frequency ERW piping to seam failures and the potential of its piping for SCC in the absence of sound technical justifications for discounting these risk factors. The safety of the public depends on pipeline operators maintaining the integrity of their pipelines. Conducting an effective risk analysis is a key step in order for pipeline operators to prioritize the integrity assessment of the highest risk segments of their pipelines. If the risk analysis is not properly conducted at the baseline assessment stage, it can adversely affect an operator's entire IMP program.

In its response and at the hearing, Respondent contended that the IMP rule only required that it have a "framework" program and that the issues cited by OPS are merely improvements that it had intended to develop over time. This argument, however, is unpersuasive. The IMP rule expressly required that pipeline operators have the specified program elements in place by March 31, 2002.[11] Although continual evolution of IMP plans is certainly contemplated by the IMP rule (indeed, operators are required to update their programs as new data is acquired), when required program elements such as prioritization of baseline assessments by risk were due to be implemented, an operator's process for doing so must be mature, and nothing in the record warrants concluding otherwise. In this case, all of the citations arose from Respondent's omission of required program elements or lack of technical justification for program methodologies.

Respondent also questioned the adequacy of notice of how OPS intended to interpret and enforce the IMP rule. The history of the IMP rule, however, demonstrates that OPS went to great lengths to provide operators with pre-enforcement guidance on how it would interpret and apply the requirements of the IMP rule including holding public meetings, developing a extensive IMP websites, publishing detailed frequently asked questions (FAQs), and even publishing the inspection protocols later used by OPS in conducting IMP compliance inspections. For example, OPS pointed out that the need to assess lines for the risk of cracks including SCC was emphasized during a 2002 Workshop attended by Respondent's personnel in which crack tools were specifically listed as assessment methods.[12] Respondent has presented no information that

[11] 49 C.F.R. § 195.452(b)(1).

[12] See 66 FR 35319 and 67 FR 31399 for more information on the IMP workshops.

would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $100,000 for violating 49 C.F.R. § 195.452(b)(3).

With respect to Item 2a, the Notice proposed a civil penalty of $25,000 for Respondent's failure to consider the results of previous integrity assessments including previously identified defect type and predicted growth rate in establishing an integrity assessment schedule prioritizing its pipeline segments by risk. In order for a pipeline integrity program to be effective, a key step is prioritizing the integrity assessment schedule by risk. In order to prioritize an integrity assessment schedule by risk, an operator must consider all risk factors that reflect the risk conditions each pipeline segment. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $25,000 for violating 49 C.F.R. § 195.452(e)(1)(i).

With respect to Item 2b, the Notice proposed a civil penalty of $25,000 for Respondent's failure to consider repair history in establishing its integrity assessment schedule. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $25,000 for violating 49 C.F.R. § 195.452(e)(1(iii).

With respect to Item 2c, the Notice proposed a civil penalty of $25,000 for Respondent's failure to consider local environmental factors including soil corrosivity, subsidence, climactic conditions, and geo-technical hazards in establishing its integrity assessment schedule. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $25,000 for violating 49 C.F.R. § 195.452(e)(1)(vii).

With respect to Item 2d, the Notice proposed a civil penalty of $25,000 for Respondent's failure to consider physical support of a segment such as by a cable suspension bridge in establishing its integrity assessment schedule. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $25,000 for violating 49 C.F.R. § 195.452(e)(1)(ix).

With respect to Item 3b, the Notice proposed a civil penalty of $50,000 for Respondent's failure to demonstrate that the weight assigned to product type by the risk model it used to identify the need for preventative and mitigative measures was justified given Respondent's actual operating experience. In order for a pipeline operator to effectively identify the need for preventative and mitigative measures, the risk analysis must be meaningful. In order for the risk analysis to be meaningful, the weights assigned to the risk factors must correspond as closely as possible to the actual risks on the system. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $50,000 for violating 49 C.F.R. § 195.452(i)(2).

With respect to Item 4, the Notice proposed a civil penalty of $15,000 for Respondent's failure to integrate available information concerning the age of in-line inspections and hydrostatic pressure tests into its integrity management analysis. In order for a pipeline integrity program to be effective, the information analysis must be meaningful. In order for an information analysis to be meaningful, all available pipeline data must be used. Respondent argued that its system is comprised of eight separate legacy business units acquired over time and that assigning one score to lines that had never been assessed and identical scores to all other lines was the approach that was the most useful to the company. While Respondent is correct that those pipelines of its business units that had never been assessed should have received higher risk scores, it does not follow that its decision to treat all other lines equally was justified. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $15,000 for violating 49 C.F.R. § 195.452(f)(3).

With respect to Item 5, the Notice proposed a civil penalty of $50,000 for Respondent's failure to use available pipeline data including basic information on seam design, block valve rating, maximum expected discharge pressure, and internal corrosion inhibitor as inputs in its information analysis. In order for a pipeline integrity program to be effective, the information analysis must be meaningful. In order for an information analysis to be meaningful, all available pipeline data must be used. While Respondent provided some additional information in connection with the hearing concerning its subsequent activities, it failed to show that its decision not to use the available data specified in the Notice during the relevant time period was justified. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $50,000 for violating 49 C.F.R. § 195.452(g).

With respect to Item 6, the Notice proposed a civil penalty of $10,000 for Respondent's failure to include eleven specified HCA line sections containing hazardous liquids in its BAP. Ensuring that all pipeline segments that could affect a HCA are included in an integrity management program is an important part of ensuring pipeline integrity. Respondent has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $10,000 for violating 49 C.F.R. § 195.452(e)(1)(iv).

For the forgoing reasons, I assess Respondent a total civil penalty of $325,000. Respondent has the ability to pay this penalty without adversely affecting its ability to continue in business.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-300), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-8893.

Failure to pay the S325,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a Compliance Order with respect to Items 1-7 in the Notice. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under Chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to Item 1 of the Notice:

   Incorporate provisions in the risk model and other associated aspects of the integrity management program to account for and address both the susceptibility of pre-1970 low frequency ERW piping to seam failures and the potential of any piping for SCC, or provide a thorough engineering analysis containing sound technical justifications for their exclusion;

2. With respect to Item 2 of the Notice:

   Revise the risk factors in the Integrity Management program to include data from:

   (a) Results of previous integrity assessments, including previously identified defect type and predicted defect growth rate;

   (b) Repair history:

   (c) Local environmental factors such as soil corrosivity, subsidence, climatic conditions, and geo-technical hazards; and

   (d) Physical support of a segment such as a cable suspension bridge;

3. With respect to Item 3 of the Notice:

   (a) Provide adequate justification and documentation in general for the basis of risk factor weighting and scores;

   (b) Either provide specific justification for the heavy weighting of product type in the risk rankings, or adjust the weighting to be more in line with Respondent's actual operating history;

   (c) Revise and substantiate the assignment of weighting factors for HCA type; and

   (d) Either justify the weighted averaging of risk scores towards shorter lines, or revise the weighted averaging process for equitable treatment for all line segment lengths:

4. With respect to Item 4 of the Notice:

   Revise the risk model scoring to differentiate the age of previous in-line inspections and hydrostatic pressure tests;

5. With respect to Item 5 of the Notice:

   Either substantiate and justify the exclusion of pipeline integrity data, or incorporate all appropriate available pipeline integrity data even though similar data may not be uniformly available for all line segments;

6. With respect to Item 6 of the Notice:

   Conduct a thorough review of records and physical examination, as appropriate, of the eleven sections of lines that were improperly excluded from the BAP schedule due to being classified as idle lines. As a result of that review and examination, either drain and evacuate those lines found to still contain hazardous material, or revise the status of any line still retaining hazardous material in the risk model and other associated aspects of the integrity management program;

7. With respect to Item 7 of the Notice:

   Incorporate field information to identify new HCAs, update existing HCA information, and update the BAP and the Information Analysis to reflect the updated HCA information;

8. Complete Items 1-7 above within 180 days of receipt of this Final Order unless an item or portion thereof is required to be completed sooner by another PHMSA Order applicable to any portion of Respondent's system in which case that earlier time requirement shall apply. The management and analytical process guidance used to implement the program

must be of sufficient detail and specificity to clearly articulate the necessary steps to perform each program element and ensure repeatability, describe the key input information sources, define the process output products, their documentation (including the justification for decisions), and document retention requirements and specify organizational responsibilities for performing key process steps; and

9. Provide ten copies of all documentation demonstrating the completion of each item above to the Director, Eastern Region. The documentation must include reference numbers to the items above.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

Failure to comply with this Compliance Order may result in the assessment of civil penalties of up to $100,000 per violation per day, or in the referral of the case for judicial enforcement.

WARNING ITEMS

The Notice did not propose a civil penalty or corrective action for Items 8, 9, 10, and 11 in the Notice. Therefore, these are considered to be warning items. Respondent is warned that if it does not take appropriate action to correct these items, enforcement action will be taken if a subsequent inspection reveals a violation. The warnings were for:

Notice Item 8 – Respondent's failure to document the technical justifications for changes it made to its BAP between March 31, 2002 and March 15, 2003 in accordance with the requirements of § 195.452(c)(2):

Notice Item 9 – Respondent's failure to adequately establish a means of ensuring that information sufficient to determine whether or not a condition identified during an in-line inspection represents a potential integrity threat is promptly obtained in accordance with the requirements of § 195.452(h)(2);

Notice Item 10 – Respondent's failure to consider in-line inspection tool tolerances in its process for reviewing integrity assessment results in accordance with the requirements of § 195.452(f)(8): and

Notice Item 11 – Respondent's failure to adequately establish criteria for reporting and addressing conditions identified during in-line inspections that meet the relevant categorical thresholds for remedial action in accordance with the requirements of § 195.452(f)(4).

Under 49 C.F.R. § 190.215, Respondent has a right to submit a petition for reconsideration of this Final Order. Should respondent elect to do so, the petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of a petition automatically stays the payment of any civil penalty assessed. All other terms of this Final Order, including any required corrective action, remain in full effect unless the Associate Administrator, upon request, grants a stay.

Failure to comply with this Final Order may result in the assessment of civil penalties of up to $100,000 per violation per day, or in the referral of the case for judicial enforcement. The terms and conditions of this Final Order are effective on receipt.

Stacey Gerard
Associate Administrator
for Pipeline Safety

JUN 26 2006

Date Issued