Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

In the Matter of	)	
	)	
ExxonMobil Pipeline Company	)	CPF No. 4-2013-5027
Pegasus Pipeline incident	)	Notice of Probable Violation
(March 29, 2013), Mayflower, Arkansas	)	

RESPONDENT'S
POST HEARING BRIEF

INTRODUCTION

As drafted, the Notice of Probable Violation (NOPV) issued to ExxonMobil Pipeline Company (Respondent or Company) implies that violations must have occurred because there was an incident. The Pipeline Safety Act (PSA) has no strict liability provision, however, a fact that was admitted by the Pipeline and Hazardous Materials Administration (PHMSA or Agency) at the Hearing. The Agency must therefore prove alleged violations, not presume them. The Agency has not established that proof in this case.

I. The Law Applicable to LF-ERW Pipe

In order to fully evaluate the allegations made by PHMSA in this matter, particularly for NOPV Items 1-4 and 7, it is necessary to understand the state of the law underlying integrity management regulation of low frequency electric resistance welded (LF-ERW) pipe. The National Transportation Safety Board (NTSB), PHMSA and leading experts in pipeline metallurgy and risk management nationally have not yet been able to develop a standard process that allows operators to identify all features associated with the risk of seam failure on LF-ERW pipe, because current technology does not provide adequate data to identify all ERW anomalies. The NOPV in this matter, however, flatly asserts that Respondent had "*more than adequate information*" to be able to do just that. *NOPV Item 1, p. 2.* That assertion is simply wrong. The Agency itself has not been able to produce rules or guidance that would direct operators to find such isolated anomalies, and the leading experts in this area – both Respondent's and the government's – have concluded that technology is not yet capable of finding all these anomalies.

Various methods have been used over the decades to manufacture steel pipe used in construction of oil and gas pipelines. One of the methods used prior to 1970 involved joining the long seam of pipe segments by LF-ERW. In 1986, two long seam failures of pre-1970 LF-ERW pipe occurred in Minnesota, leading the Office of Pipeline Safety (OPS) to issue alerts to industry in both 1988 and 1989. *Exhibit 72, OPS Alert ALN-88-01 (Jan. 28, 1988); Exhibit 73, OPS Alert ALN-89-01 (Mar. 8, 1989).* The alerts simply warned that LF-ERW welds had the potential to fail in limited circumstances, and that operators should consider that potential risk while conducting pipe inspection and maintenance activities.

In 1994, and again in 2000 (in the integrity management program (IMP) rule), OPS issued rules directing liquid pipeline operators to conduct hydrostatic pressure testing of pre-1970 LF-ERW pipe in certain circumstances. *Exhibit 74, Final Rule, 59 Fed. Reg. 29379 (June 7, 1994)*; *Exhibit 75, Final Rule, 65 Fed. Reg. 75378 (Dec. 1, 2000).* The Agency also commissioned a study resulting in a report issued in 2004, proposing a protocol for operators to use in evaluating the risk posed by pre-1970 LF-ERW pipe. *Hearing Exhibit No. 3 (Baker-Kiefner Report)*. The protocol it proposed was not incorporated into OPS rules, but operators were encouraged to follow it. Respondent not only followed that protocol, it retained one of the study co-authors (John Kiefner) to help adapt the protocol specifically to the Company's IMP.

The OPS rules regarding pre-1970 LF-ERW pipe for liquid lines are minimal, and more advisory than prescriptive. In fact, there are only three places in the entirety of Part 195 that address pre-1970 LF-ERW pipe: 49 C.F.R. Part 195.303(d) (which was a one-time opportunity to conduct risk based alternatives to hydrotesting); and Parts 195.452(e)(1)(ii) (requiring consideration of manufacturing information as a risk factor in IMP threat identification) and 195.452(j)(5) (requiring assessment methods for LF-ERW pipe susceptible to seam failure to be capable of assessing seam integrity, among other things). Where a segment is found to be susceptible to longitudinal seam failure under the IMP rules, an operator is directed to use certain integrity assessment tools. Other than the requirement to "consider" the risk of ERW seam failure, however, the Agency has offered no specific guidance to operators beyond the non-mandatory 2004 Baker-Kiefner report.

In 2007, a pipeline accident in Carmichael, Mississippi involving LF-ERW pipe led the NTSB to issue two formal recommendations to OPS (by then part of PHMSA). Recommendation P-09-01 urged PHMSA to "conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in electric resistance welded (ERW) pipe." *Exhibit 68, NTSB Accident Report, NTSB/PAR-09/01, at p. 51 (Nov. 1, 2007).* Recommendation P-09-02 encouraged PHMSA to "implement actions needed [based on the results of the study requested in P-09-01]." *Id.* NTSB stated that its reason for making such recommendations was a conclusion that *"[PHMSA's] current inspection and testing programs are not sufficiently reliable to identify features associated with longitudinal seam failures of ERW pipe prior to catastrophic failure*" of an operating pipeline. *Exhibit 69, Letter from NTSB to PHMSA, at p. 3 (Oct. 27, 2009), transmitting recommendations* (emphasis added).

NTSB's recommendations to PHMSA regarding LF-ERW pipe went unaddressed for several years. The NTSB issued letters to the Agency in 2010, 2011 and 2012, inquiring about the status of PHMSA's response on the issue. In the 2010 letter from NTSB Chair Deborah Hersmann to PHMSA Administrator Cynthia Quarterman, NTSB stated that it was "disappointed" that PHMSA had not yet commenced a study on LF-ERW pipe. *Exhibit 70, Letter from NTSB to PHMSA, at p. 1 (Dec. 29, 2010).* In a subsequent letter, NTSB noted that it understood the Agency finally had commissioned the ERW study, which was expected to be completed by the Battelle Memorial Institute by November 2012. *Exhibit 71, Letter from NTSB to PHMSA, at p. 2 (Oct. 19, 2011).*

It was not until five years after the NTSB issued Recommendations P-09-01 and P-09-01 to PHMSA about LF-ERW pipe that Battelle issued an interim report." *Exhibit 65, Battelle Institute, "Final Interim Report" on ERW Seam Failures (Sept. 20, 2012) (Battelle Interim Report).* A little more than a year after that, Battelle issued a "Final Summary Report," dated October 23, 2013. Significantly, this "Final Summary" report was issued after the Mayflower incident. The October 2013 report commissioned by PHMSA noted that:

> …it is clear that gaps remain both in the understanding of the [ERW] failure process, and in quantifying the effectiveness of current schemes and technology to manage the ERW pipeline network. As such, the work initiated under [this study project] is being continued to bridge those gaps.

Exhibit 66, Battelle Final Summary Report on ERW Seam Failures, p. vi (Oct. 23, 2013) (Battelle Final Summary Report).

The Battelle study commissioned by PHMSA is still ongoing, long after NTSB issued its Recommendations on point, and long after the Mayflower incident that is the subject of this NOPV. On May 31, 2014, Battelle issued its "12th Quarterly Report" on the continuing work on this issue. That update notes that 15 Task Reports have been issued under Phase I of the project, but that the stated goal of the study has not yet been met: "to identify the factors the pipeline operators must consider in order to assure that their ERW pipelines are safe." *Exhibit 67, Battelle ERW Study, 12th Quarterly Report,* p. 1, "Public Page" (May 31, 2014).

Battelle's reports note that the frequency of occurrence of long seam weld failures on LF-ERW pipe has been declining since the 1960s. *Exhibit 65, Battelle Interim Report p. 76 (Sept. 20, 2012).* That trend is obviously important, as more than 25% of all liquid pipelines in the U.S. contain pre-1970 ERW pipe. *PHMSA, Hazardous Liquid Annual Data 2012 (as of May 1, 2014) available at* www.phmsa.dot.gov (includes direct current welded pipe). If the risk of seam failure was greater than it is, PHMSA could direct more mandatory inspection or testing activities than it has. To the credit of NTSB and PHMSA, however, study of this risk continues, with a goal of providing pipeline operators with better tools and methods to predict and identify LF-ERW long seam anomalies that could otherwise lead to failure in limited circumstances.

As discussed below, Respondent complied with all applicable law and guidance in evaluating the Pegasus Pipeline for susceptibility to long seam failure of LF-ERW pipe. Post-incident analysis confirmed that the anomaly was not capable of reliable detection. In sum, more than five years of vigorous study and analysis by PHMSA to develop actions that could be implemented by pipeline operators to eliminate LF-ERW failures has offered no definitive results or guidance, yet PHMSA's NOPV directly faults Respondent for not completely eliminating the possibility of a LF-ERW seam failure on a pipeline that operated for over 60 years without incident. The Battelle study on ERW issues, commissioned by PHMSA, continues, but its preliminary findings support the Company's position in this proceeding.

II. Respondent Complied with the Law Applicable to LF-ERW Pipe with an IMP Plan, Engineering Analyses on Seam Risk, ILIs and Hydrotests (NOPV Items 1-4, 7)

A. Overview of Relevant NOPV Allegations

In NOPV Items 1 – 4 and 7, PHMSA asserts five violations of its IMP regulations concerning LF-ERW pipe. PHMSA specifically alleges that Respondent failed to (1) consider the susceptibility of pre-1970 LF-ERW pipe seam failure as a risk factor when establishing its assessment schedule, citing 49 C.F.R. Part 195.452(e)(1) *(NOPV Item 1)*; (2) establish a five year reassessment interval, citing Part 195.452(j)(3) *(NOPV Item 2)*; (3) obtain a variance from the five year interval to extend the seam/crack tool assessment of Conway to Corsicana in violation of its procedures (IMP Plan 5.1), citing Part 195.452(b)(5), (j)(4) and (i) *(NOPV Item 3)*; (4) prioritize higher risk segments of the Pegasus Pipeline for reassessment, citing 195.452(e) and (j)(3) *(NOPV Item 4);* and (5) follow internal procedures (IMP Plan 5.4 and OIMS 2.4) by not updating its risk assessment when the TFI tool run was delayed, citing 49 C.F.R. Part 195.452(b)(5) and (j)(1) and (2) *(NOPV Item 7)*.

All of these allegations hinge on PHMSA's presumption, conveniently made after the fact, that the Pegasus Pipeline should have been determined to be susceptible to seam failure.

All of these allegations, however, are unsupported by the facts, the law and available guidance. The allegations and their underlying presumption also conflict with the opinions of the nation's leading experts on these issues.

B. Respondent Appropriately Conducted Seam Susceptibility Analyses and Pressure Testing of LF-ERW Pipe

As discussed in Section I, above, other than alerting operators to the potential risk of seam failure on some LF-ERW pipe, PHMSA has provided little regulation or guidance on how to anticipate or locate LF-ERW anomalies. The most recent research into these issues was commissioned by PHMSA and conducted by Battelle, which concluded (notably, after the Mayflower incident) that technology and methods are not yet well enough developed to be able to identify all LF-ERW anomalies, even as the occurrence of LF-ERW related incidents is declining. The record in this case shows that Respondent did *far more* than required by existing rules or guidance to identify LF-ERW pipe that is susceptible to seam failure.

Respondent incorporated LF-ERW consideration procedures into its IMP program from the very outset, using the services of one of the co-authors PHMSA retained to develop guidance on the topic. The Company carefully considered all relevant risk factors, based on all available information, in establishing its baseline and reassessment schedules. Respondent subsequently completed four separate engineering analyses specific to the Pegasus Pipeline, looking at the risk of seam failure and incorporating information from three hydrostatic pressure tests and three in-line inspection (ILI) runs (one with a crack/seam tool).

John Kiefner, who co-authored the 2004 LF-ERW seam failure risk study commissioned by PHMSA, and who was part of the 2012/2013 Battelle study commissioned by PHMSA to further examine ERW risk, has submitted an affidavit for this matter. As stated clearly in his affidavit, hydrostatic test failures alone are not indicative of susceptibility to seam failure. *Hearing Exhibit No. 1, Kiefner Aff. ¶ 13*. There must be evidence of fatigue-related failures, selective seam corrosion or other time dependent defects (such as stress corrosion cracking). *Id.* Kiefner goes on to describe his review of the data associated with the Mayflower incident, noting that the "point of failure showed no evidence of fatigue." *Id. at ¶ 17.* More significantly, Kiefner concludes that

> [he has] reviewed the integrity data that would have been available to EMPCo prior the incident regarding the Conway to Corsicana testable segment. Based upon that review, EMPCo's conclusion that the segment was not seam-failure-susceptible under the federal regulations was reasonable, and was consistent with the seam failure susceptibility determination guidance available prior to March 29, 2013.

Id. at ¶ 19. Kent Muhlbauer, a national pipeline risk management expert who has also worked with PHMSA, also submitted an affidavit stating that

> It is my opinion that the Company properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus Pipeline, and complied with the Part 195 IMP regulations.

Hearing Exhibit No. 2, Muhlbauer Aff. at ¶ 11.

At the Hearing, PHMSA raised additional issues concerning Respondent's methods and analyses used to evaluate seam risk, suggesting that the Company did not sufficiently consider that the pipe was brittle, and therefore the continued focus on fatigue analysis was misplaced. PHMSA asserted that Respondent should have focused on the hardness and toughness of the pipe in its analyses. *Transcript of Hearing on PHMSA NOPV CPF 4-2013-5027 (Jun. 11, 2014) (Transcript), p. 111, lines 1-9.*

The Company's detailed seam susceptibility and fatigue analyses expressly considered all available information regarding the Pegasus Pipeline, including its manufacturing history, the pipe material properties (such as documented fracture toughness values), sixty years of operating and maintenance history, leak history, and the results of prior pressure tests and integrity assessments (and subsequent metallurgical analysis). In the absence of evidence of other failure mechanisms on the Pegasus Pipeline, including pressure reversals, environmental cracking, and hardness related to the seam, the Company relied on the Baker-Kiefner process which directs an operator to analyze pressure cycle-induced fatigue.[1] Indeed, the Company directly consulted with John Kiefner, one of the world's leading experts on LF-ERW seam failure analysis. Contrary to PHMSA's allegations at the Hearing, Respondent's Pipelife fatigue analysis software (developed by John Kiefner) specifically considers toughness (*i.e.*, the measure of a pipe's brittleness) as a factor in the analysis, and the Company followed the manual's instruction to use actual representative toughness values when they are available.[2]

In addition, at the Hearing, PHMSA asserted that Respondent should have run its hydrotests at higher pressures, from 90-100% SMYS, in order to properly assess seam risks or threats. *Transcript, p. 105, lines 8-15*. The Agency's regulations do not specify any such pressures or hydrotest parameters for LF-ERW pipe beyond compliance with Subpart E, however.[3] To that very point, Kiefner noted in his affidavit that "the level of hydrostatic test

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[1] As attested to by Kiefner, the Company's conclusion that the segment was not seam failure susceptible was "reasonable" and "consistent with available guidance," further based on the examinations of the prior hydrostatic test failures, there was "no evidence of excessively hard heat affected zones." *Hearing Exhibit No. 1, Kiefner Aff. ¶¶ 18, 19.*

[2] The 2011 analysis used a seam toughness CVN value of 7 because it was the average representative toughness value documented by the Hurst 2006-2007 analyses of the 2005-2006 hydrotest failures. Further, Kiefner notes that his review of the pipe material properties indicates that the anomaly that caused the Pegasus incident "was not capable of reliable detection given that it exhibited atypical characteristics not frequently seen before in the industry." *Hearing Exhibit No. 1, Kiefner Aff. ¶ 24*.

[3] This issue was raised at the Hearing and Respondent pointed out that there are no Agency regulations or guidance that <u>require</u> a higher hydrostatic test pressure for this type of pipe. *Transcript, p. 105, lines 17-18*. While PHMSA suggested that 49 C.F.R. Part 195.303(d) has bearing on this issue, as explained by Respondent at the Hearing – and notably not challenged by PHMSA – that provision was enacted in 1998 and established a one-time historical opportunity for operators to elect a risk-based alternative to pressure testing of pre-1970 pipe, and specifically at subsection (d) for pre-1970 LF-ERW pipe. *Transcript, p. 105, line 16 – p. 106, line 11*. That provision was enacted prior to the IMP rules, and other than specifying considerations for seam susceptibility analyses, it has no other relevance. *Id.* Further, 195.303(d) required pressure testing of pre-1970 LF-ERW pipe that was susceptible to seam

pressure employed in 2006 on the Conway to Corsicana segment was consistent with the 49 C.F.R. Part 195 regulatory requirements." *Hearing Exhibit No. 1, Kiefner Aff. ¶ 22.*

Even after its conclusion that the Pegasus Pipeline was not susceptible to seam failure, and despite the lack of direction or guidance from the Agency, the Company continued to conduct tests and analyses, using both company engineers and third parties, to reevaluate whether the line was susceptible.[4] No actionable anomaly was ever identified on the segment of pipe that failed in the Mayflower incident. Significantly, even after the incident, metallurgical examination revealed a pipe joint with highly unusual chemical and mechanical properties and unique characteristics at the point of failure. *Hearing Exhibit No. 1, Kiefner Aff. ¶¶ 16, 17.* There is no evidence that the anomaly that failed was capable of reliable detection by technology and methods of inspection used at the time in compliance with applicable law.

The Agency conducted an intensive inspection of the Company's IMP program and LF-ERW procedures in 2007, specifically with respect to the Pegasus Pipeline, and found no issue with those procedures or their implementation. The record shows that Respondent complied with all of PHMSA's existing rules and guidance in trying to anticipate and identify LF-ERW seam susceptibility issues on the Pegasus Pipeline. *Hearing Exhibit No. 1, Kiefner Aff. ¶ 21* ("The seam-integrity assessment activities that EMPCo employed on this segment of pipe were consistent with the Baker Report Flow Chart and IMP regulations and guidance in effect at the time.").

C. Respondent Complied with Applicable Law and Guidance in Conducting ILI of the Pegasus Pipeline

Given all available information and analyses, conducted over a period of time, Respondent concluded that the Pegasus Pipeline was not susceptible to seam failure. Despite that conclusion, the Company elected to voluntarily run a seam/crack tool in 2012. The next reassessment after the 2010 ILI on the Conway to Corsicana segment was not due until 2015, but the Company voluntarily decided to employ the seam/crack tool well in advance of that date.

Because a seam/crack tool was not required, it was not subject to the variance reporting requirements under the IMP rules or the Company's IMP procedures, as alleged in NOPV Item 3. The Company's IMP Manual Section 5.1 incorporates verbatim the language of Part 195.452(j)(3), which requires an operator to request a variance when it cannot meet the 5 year interval. The rules do <u>not</u> require an operator who *voluntarily* elects to reassess a line with a seam tool, however, to request a variance.

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failure pursuant to pressure levels under Part 195 Subpart E pressure test which is consistent with the pressure test that Respondent performed in 2006 on the Pegasus Pipeline.

[4] Although not directly relevant to the allegations set forth in the NOPV, at the Hearing and in the Agency's Pipeline Safety Violation Report (PSVR), PHMSA suggests that the Company has not updated its LF-ERW susceptibility analysis in light of a 2012 incident in Torbert, Louisiana or participated in industry research regarding these issues. These statements are inaccurate and not germane to this proceeding.

Similarly, since the decision to run a seam/crack tool was not required under IMP, it was not therefore subject to the prioritization process at the base of NOPV Item 4. Contrary to the Agency's allegations in support of Item 4, the decision to run Patoka to Conway segment first was based on an analysis that the Patoka to Conway segment experienced (i) more hydrostatic seam failures on a LF-ERW per mile basis; (ii) more pressure reversals; (iii) shorter theoretical fatigue life based on existing data; and (iv) three girth weld leaks not present in Conway to Corsicana. Also, in the same year, the Company assessed the Conway to Corsicana segment with a magnetic flux leakage combo ILI tool.

For the foregoing reasons, Items 1 – 4 of the NOPV should be dismissed or rejected because they are neither supported by the law or facts, and they are all based on an incorrect after-the-fact presumption: that the Company should have deemed the Pegasus Pipeline susceptible to seam failure. PHMSA goes on to allege in Item 7 of the NOPV that Respondent failed to consider preventative and mitigative (P&M) measures (as incorporated into the Company's internal procedures), by not updating its risk assessment when the voluntary TFI tool run was delayed. As reflected by the record, that allegation is simply incorrect. The Company revised its seam failure susceptibility analysis risk assessment in March of 2011, and it was scheduled to be reviewed again in 2013. The re-assessment interval was conservative and no changes had occurred that would affect the assessment. Further, no TFI seam/crack tool run was even required, since all prior risk assessments had concluded that there was no risk of long seam failure. Simple logic underscores how this alleged violation is without support, given that no anomaly was reported when the Company ultimately did run the TFI tool in 2012-2013; since crack growth is typically a time dependent threat, it was even less likely that any anomaly would have been discovered by an earlier tool run, as suggested by the allegations in Item 7.

NOPV allegations 1 - 4 and 7, all of which rely upon PHMSA's presumption that the Pegasus Pipeline should have been determined to be susceptible to seam failure, are unsupported by the facts, the law and available guidance. They also conflict with the opinions of the nation's leading experts on these issues. The record in this case clearly shows that Respondent did *far more* than required by existing rules or guidance to identify LF-ERW pipe that is susceptible to seam failure. In establishing its assessment schedules, the Company carefully considered all required risk factors based on all available information, expressly including risks associated with LF-ERW pipe. The Company subsequently completed four separate engineering analyses to further evaluate the risk of seam failure on the Pegasus Pipeline, incorporating information from three hydrostatic pressure tests and three in-line inspection (ILI) runs (one with a crack/seam tool). Each analysis indicated that the line was not seam failure susceptible and the Company performed its integrity assessments and evaluations accordingly and in compliance with the IMP regulations and its internal procedures.

III. PHMSA Has Not Proved Alleged Violations Nos. 5-6 or Nos. 8-9

A. NOPV Item 5

PHMSA alleges that two locations, "MP 164.051" and "MP 142.394," were identified as immediate repair conditions on a preliminary report from the tool vendor that was received by Respondent on August 9, 2010. PHMSA asserts that instead of considering this information as presenting "immediate" conditions, Respondent instead treated the anomalies as confirmation or validation digs, and that the Company did not declare them as "immediates" until the sites were excavated. As a result, PHMSA asserted at the Hearing that Respondent was "declaring discovery in the ditch" and failed to take appropriate actions for "immediate conditions" pursuant to 49 C.F.R. Part 195.452(h). *Transcript, p. 22, line 22.* To the contrary, as set forth in the Pre-Hearing Brief and stated in the Hearing, both of these allegations are incorrect as a matter of fact and law, because: (1) the vendor reports were received on August 23, 2010, and January 10, 2011, respectively; and (2) in both instances, the Company took prompt action to efficiently and effectively remediate the anomalies, in accordance with its IMP procedures that have been reviewed and inspected by PHMSA numerous times.

The first anomaly at Site MP 164.051 was not identified as an immediate condition because it was estimated to be a 72% wall loss anomaly on the preliminary vendor report that was provided to Respondent on August 23, 2010.[5] *Hearing Exhibits No. 23 and 24*. Such an anomaly is not classified as an "immediate" condition unless and until it is greater than 80% wall loss. *49 C.F.R. Part 195.452(h)(4)(i)(A).* The Company added tool tolerance, in accordance with its internal procedures that exceed the regulatory requirements. *Transcript, p. 29, lines 12-23; Exhibit 57, Respondent's IMP Manual, Appendix K, Validation and Repair Process (2010).*[6] As a result, the Company promptly took action by declaring the anomaly as a potential "immediate" on the same day and excavated, examined and repaired it within five days. *Hearing Exhibit No. 25*.[7] As further explained by Respondent at the Hearing,

> Our program makes an analogy between an <u>*unvalidated*</u> preliminary report and an immediate repair and a safety related condition. So, we have five days to validate that report and then five days to fix it. And so, we immediately convene a discussion internally when we receive that report and begin to take those steps as if it were a safety [related] condition. So, we repaired it within that very first five days.

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[5] The NOPV erroneously states Respondent received the preliminary report on August 9, 2010, but that is a reference from the vendor's database, <u>not</u> the date information was transmitted to Respondent. PHMSA stated at the Hearing that this was "the first time [they had] seen that [date]." *Transcript, p. 26, lines 19-20.* That statement is simply unsupported by both the NOPV itself and further discussion at the Hearing. PHMSA cites to the correct receipt in NOPV Item 6 where the correct receipt date of August 23, 2010, is set forth in the Table at p. 6 of the NOPV, last line, second column. PHMSA attempted to suggest in the Hearing that the data must have been available on August 9, 2010, due to the wording by the vendor in an August 23, 2010, email attached as Hearing Exhibit 23 that "Today is the day [Respondent] wanted [the data] sent to him." *Transcript, p. 18, line 3.* To the contrary, this is simply a reference to the fact that the data was due to be provided to the Company on August 23, 2010, consistent with Respondent's requirements that the vendor provide preliminary reports within 30 days of completion of the 2010 Conway to Corsicana ILI. To suggest otherwise is pure conjecture on the part of the Agency without any factual basis whatsoever.

[6] Notably, this specific procedure has been inspected many times by PHMSA and the Agency has not cited any concerns.

[7] In this instance, the anomaly did, in fact, turn out to be an immediate with greater than 90% wall loss. *Transcript, p. 29, lines 12-19.*

Transcript, p. 28, lines 11-19 (emphasis added); *Exhibit 58, Respondent's IMP Manual, Section 2.3.5.4.2-4 (Safety-Related Condition Requirements) (2010).* In PHMSA guidance, the Agency endorses consideration of safety-related conditions as they relate to immediate repairs.[8] Further, PHMSA guidance expressly provides for the discovery of immediates upon excavation and examination. *Exhibit 79, PHMSA Liquid IMP Frequently Asked Question (FAQ) 7.19*.

The second anomaly referenced in the NOPV as Site MP 142.394 was not included in the August 23, 2010, preliminary report at all, but instead was called out in the final report from the vendor that was received by Respondent on January 10, 2011.[9] *Hearing Exhibit No. 30.* Respondent determined that this anomaly was an immediate condition based on orientation and proximity to a high consequence area. As reflected in Hearing Exhibit 31 and related documentation, the Company immediately scheduled the anomaly for excavation, made relevant one call notifications, and repaired the anomaly two days later, on January 12, 2011, when it was excavated.[10]

NOPV Item 5 should be dismissed for failure to state a claim given that PHMSA has not produced evidence in support of either allegation regarding the anomalies in question, and Respondent fully complied with the IMP rules and procedures.

B. NOPV Item 6

PHMSA cites four occasions where Respondent allegedly failed to declare discovery of actionable anomalies within 180 days of an ILI assessment, per 49 C.F.R. Part 195.452(h)(2), "despite the availability of adequate information in the vendor reports to make such determinations." The Agency is incorrect as a matter of fact and law. In all four instances, the Company did not receive ILI data from the vendor until near the end of the requisite 180-day period. As a result, in all four instances, adequate information was <u>not</u> available and 'discovery' was impractical given the late transmittal of data. PHMSA's IMP regulations and guidance allow for situations where vendor data is received so late as to make declarations of "discovery" within that time period impracticable. *49 C.F.R. Part 195.452(h)(2).*

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[8] *See e.g., Exhibit 80, Notice of Amendment in re: Cenex Pipeline Company, CPF 5-2011-5018M (July 26, 2011)* (citing an operator under 49 C.F.R. Part 195.452(h) for failure to reference its safety-related condition report procedure in its IMP manual related to immediate conditions to require a safety-related condition report where a repair cannot be made within 5 days of determination or 10 days of discovery).

[9] This is a different anomaly than cited to in the Agency's PSVR, and at the Hearing PHMSA further confused the issue by citing to other anomalies that are not alleged in the NOPV. *Hearing Exhibit No. 32; Transcript p. 21, lines 23 – p. 22, line 17.* The NOPV clearly alleges a violation with respect to an anomaly at MP 142.394, however; given that is the specific allegation at issue, any discussion at the Hearing regarding other anomalies is simply irrelevant.

[10] Respondent has confirmed that page 3 of the PL-0751 form mistakenly identifies January 5, 2011, as the discovery and repair date. Related documentation supports that the final report was received on January 10, 2011, and that the repair occurred on January 12, 2011. *See Hearing Exhibit No. 31* (repair form signed Jan. 12, 2011; attached dig sheets printed on Jan. 10, 2011); *Hearing Exhibit No. 27* (final ILI report and repair summary noting receipt on Jan. 10, 2011 and repair on Jan. 12, 2011)*; Hearing Exhibit 30* (email correspondence regarding the final report dated Jan. 10, 2011); *see also Exhibit 59, Email from C. Gorman dated Jan. 10, 2011* (noting that date as day zero for the potential immediate).

At the Hearing, PHMSA asserted additional allegations not reflected in the NOPV, namely that, because the Company requested that the vendor provide data for four segments together, the vendor could not have met the 180-day deadline because of the length of the entire tool run. *Transcript, p. 39, lines 8-16, 25- p. 40, line 1*. PHMSA asserted that an operator must account for both its process and the final vendor report within the 180-day period, and that an operator cannot use the fact that a vendor provided data late in the 180-day period as the basis for an impracticability argument. *Transcript, p. 35, lines 12- p. 36, line 2.*

No Agency regulation, guidance or precedent exists that governs the particular length of a tool run in the IMP regulations. There is also little guidance on impracticability, but PHMSA has held in other cases that there are "…situations where a delay in receiving ILI results from a tool vendor may render the 180-day discovery period impracticable." *Exhibit 78, Final Order in re ExxonMobil Pipeline Company, CPF 4-2011-5016, (June 27, 2013), p. 17.*

Respondent has clearly demonstrated in the record that, in all four instances cited by PHMSA, the tool vendor did not provide the Company with the ILI data until very nearly the end of the 180-day period. This is despite express commitments by the vendor to provide preliminary data within 30 days and final data within 90 days of completion of any ILI tool run, in order to allow the Company sufficient time to validate and integrate the data within the regulatory timeframe.[11] In light of the late dates in which the final data was received, it was simply not possible to verify the ILI vendor data and to conduct data integration properly. PHMSA's assertion that the Company knew that the vendor would not be able to provide the final data within 180 days is inaccurate and not supported by the evidence.[12] As allowed by the IMP rules, Agency guidance and the Company's IMP procedures, the 180-day period was extended for acknowledged reasons, and documented in accordance with the Company's IMP Plan and the IMP regulations. *See Hearing Figure 4 and Exhibits No. 26, 33, 38 and 39* (IMP Forms 1.2 documenting each extension).

Given the lack of regulation or guidance that supports either of PHMSA's allegations in this instance, NOPV Item 6 should be withdrawn in its entirety, or alternatively, the penalty should be substantially reduced.

C. NOPV Item 8

The NOPV alleges that Respondent violated 49 C.F.R. Part 195.402(a) regarding operations and maintenance (O&M) manuals, but as noted at the Hearing, the actual allegations and facts relate to the Agency's IMP rules under Part 195.452. *Transcript, p. 63, lines 12-16*. In addition to the fact that this allegation is erroneously pleaded as a matter of law, it also fails on

[11] Specific only to the last of the four tool runs at issue, the 2013 Conway to Coriscana TFI tool run, the ILI vendor subsequently committed to providing the preliminary data within 60 days and the final data within 90-120 days. *See e.g., Exhibit 64, Email from J. Johnson (GEPII) to P. Vocke (Respondent) (April 12, 2012).*

[12] *See e.g., Exhibit 61, Email from L. Lamons (Respondent) to J. Johnson (GE PII) (Nov. 29, 2012); Exhibit 62, Email from C. Gorman (Respondent) to R. Coryell (GE PII) (Dec. 3, 2012); Exhibit 63, Email from C. Gorman (Respondent) to B. Hagerman (GE PII) (Mar. 15, 2013).*

the merits because Respondent did comply with the relevant integrity management regulations and its procedures.

PHMSA alleges under NOPV Item 8 that Respondent violated O&M provision 49 C.F.R. Part 195.402(a) by selectively using its IMP threat identification and risk assessment (TIARA) process in violation of its IMP manual (which resulted in the failure to characterize the risk of a release to certain areas). The regulation cited, 49 C.F.R. Part 195.402(a), however, is wholly unrelated to the allegations, which instead are founded on the IMP rules at 49 C.F.R. Part 195.452. *See 49 C.F.R. Part 195.402(a)* (requiring operators to prepare and follow a manual of written procedures for "conducting normal operations and maintenance activities and handling abnormal operations and emergencies."). For that reason, the Presiding Officer should dismiss (or PHMSA should withdraw) this alleged violation. Such action would be consistent with past enforcement precedent. *See Exhibit 76, Final Order in re Rocky Mountain Pipeline System, LLC, CPF 5-2004-5001 (Dec. 11, 2006) p. 7* (withdrawing the alleged violation "because the regulation cited does not relate to the alleged problem.").

Even if the claim in Item 8 is allowed to stand although incorrectly pleaded, the record clearly shows that Respondent properly applied its integrity management procedures under TIARA. The TIARA model did not identify any threats or require any P&M measures.[13] Using this software, and in consideration of recommendations and analysis performed by the engineers familiar with the Pipeline, the Company implemented P&M measures, including scheduling of three emergency flow restrictive devices and the decision to run a TFI seam/crack tool.

As explained at the Hearing, the Company's TIARA analysis assesses threats on a forward-looking basis for the next five years based on information regarding the design, construction, operation and maintenance of the pipeline until the next reassessment. As such, part of the analysis would include the knowledge that a seam tool would be run during the next five year interval. The TIARA risk score for each threat is then examined and analyzed by the Company for sensitivity to varying inputs. Specific to the 2011 TIARA analysis and risk assessment on the Conway to Corsicana segment, Respondent included comments in the TIARA inputs and performed a hypothetical threat analysis to better understand the sensitivities of the TIARA software and identify the conditions under which the model would have identified a manufacturing threat. Even though the actual (as opposed to hypothetical) TIARA analysis did not identify any threats, based on the recommendations from its engineers, the Company nonetheless implemented additional P&M measures to protect the pipeline, expressly addressing sensitive areas and drinking water bodies along the Pegasus Pipeline.

Item 8 should either be dismissed or withdrawn because it fails to state a claim, and because it is based on an inaccurate reading of facts and application of the law.

[13] In compliance with the Company's TIARA procedures, the only notification provided to management was OIMS 2A Attachment #7 which conveyed the risk score. *Exhibit 60, Email from M. Weesner (Respondent) approving OIMS 2A Attachment #7 (Mar. 15, 2011).* No other management notifications or approvals were required under TIARA or OIMS 2A because there were no elevated threats.

D. NOPV Item 9

PHMSA alleges that Respondent failed to follow its own IMP procedures by not creating Management of Change (MOC) documentation when the decision was made to merge test segments for ILI purposes. Item 9 asserts a violation of 49 C.F.R. Parts 195.452(b)(5) and (j)(1). PHMSA goes on to assert that it is the failure to follow the MOC procedures that allowed the testable segments to be merged and resulted in a dilution of the TIARA risk scores. As clearly reflected in the record and further discussed at the Hearing, however, it is evident that Respondent did in fact create not one, but <u>two</u> MOC forms to support its decision, following a risk analysis conducted in 2005 that *specifically* considered the impact of the merger of testable segments on IMP ILI assessments. *Hearing Exhibits No. 10 and 11.*

Respondent's risk analysis in 2005 expressly considered the impact of the merger of testable segments on IMP ILI assessments. Respondent concluded that there would be <u>no</u> negative impact to the integrity risk assessment process. This analysis is reflected in the two MOC forms that Respondent produced to PHMSA, in compliance with the Company's OIMS procedure 7.2.[14] *Id.* As explained in the Hearing, under Respondent's TIARA program, dynamic risk assessment threats cannot be aggregated or masked over multiple miles and, therefore, the length of a testable segment simply does not impact the identification of threats. *See Transcript, p. 69, line 23 – p. 70, line 12.* Accordingly, PHMSA's NOPV Item 9 as alleged should be withdrawn.[15]

IV. <u>The Proposed Penalty Should be Withdrawn, or Alternatively, Substantially Reduced</u>

As the Agency admitted during the Hearing, there is no strict liability under the PSA. *Transcript, p. 84, lines 21-23.* The occurrence of an incident is not by itself a basis for a violation or penalty. Because Respondent complied with all applicable rules, no penalty should apply. Even if violations are deemed to have occurred, the amount of penalty is not warranted and should be significantly reduced in compliance with the PSA.[16] NOPV Items 1 – 4 and 7 are so closely related for penalty purposes, by sharing the same elements of facts and law, that they constitute a "related series of violations" subject to the PSA statutory penalty maximum of $1 million in the aggregate. Further, all of the penalties proposed under the NOPV should be reduced in consideration of the required statutory mitigation factors.

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[14] The overall risk for potential leaks was reduced by the removal of pig traps, which included removal of potential sources of leaks (redundant piping, valves, flanges, and fittings). As a result, the MOC form did not require a risk assessment. With respect to consideration of any impact to ILI report timing, those considerations are addressed by the Part 195 regulatory timeframe and ILI vendor contract specifications.

[15] Throughout the Hearing, much of the discussion regarding NOPV alleged violations went well beyond the allegations pleaded in the NOPV itself. The discussion surrounding NOPV Item 9 was no exception, a point acknowledged by PHMSA counsel. *Transcript, p. 74, lines 6-8.* The extraneous discussions have no bearing on the allegations pled by PHMSA and are therefore to be ignored in this proceeding.

[16] As noted by PHMSA counsel in the Hearing, the proposed penalty in the NOPV is an "initial … starting point," or a "cap" and adjustment of the penalty will be considered by taking into account mitigating points made at the Hearing. *Transcript, p. 150, lines 17 – p. 151, line 7.*

A. Items 1-4 and 7 are "Related" for Penalty Purposes

NOPV Items 1 – 4 and 7 are related because they rely on the same facts and law and should constitute a single violation subject to the statutory $1 million penalty maximum for "related series of violations." *49 U.S.C. § 60122(a)(1); 49 C.F.R. Part 190.223(a)*. All of these alleged violations rely on the Agency's argument that Respondent failed to consider that the segment was susceptible to seam failure. Assessing five separate penalties that when combined exceed $1 million, based on the same facts and applicable law, contradicts the plain language of the PSA, the Agency's rules and the Agency's only guidance issued to date on the subject.

The PSA requires that "any related series of violations" occurring prior to January 3, 2012 must be capped at no more than $1 million. *49 U.S.C. § 60122(a)(1); 49 C.F.R. Part 190.223(a)*. The only legislative history on point indicates that this phrase should be applied in regard to a single incident.[17] Further, the only relevant guidance articulated by the Agency to date states that a related series of violations should include the situation where the facts and law for multiple claims "are so closely related…that they are not separate and should be considered one violation." *Exhibit 77, Final Order in re: Colorado Interstate Gas Co., CPF 5-2008-1005 (Nov. 23, 2009)*.

The facts and law underlying NOPV Items 1 – 4 and 7 are inextricably intertwined and stem from one underlying PHMSA allegation. But for the Agency's allegation that the Respondent failed to conclude that the pipe segment was susceptible to seam failure, there would not be a basis for the purported violations asserted in Items 1 – 4 and 7. Item 1 addresses the alleged failure to conclude that the pipe was susceptible to seam failure. Item 2 builds on that allegation to assert that because Respondent did not make this conclusion, it exceeded the length of time allowed to run a seam ILI tool. In turn, Item 3 alleges that Respondent failed to complete a Management of Change form for extending the five year reassessment interval allegedly violated under Item 2. Similarly, Item 4 alleges again that because Respondent failed to conclude the pipe was susceptible to seam failure, it did not properly prioritize the timing of ILI seam tool runs. In Item 7 of the NOPV, PHMSA asserts that by not updating its risk assessment when the seam tool was delayed, the Respondent failed to follow certain internal procedures. This is further underscored by the Agency's PSVR, which cites the same evidence in support of these Items. *PHMSA PSVR, CPF 4-2013-5027, pp. 7, 13, 26* (describing the relevant evidence to include hydrostatic pressure test data and IMP assessment worksheet and risk assessments); and *pp. 19 and 45* (describing the relevant evidence to include IMP risk assessments, analyses and IMP Form 2.3).

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[17] During reauthorization efforts that preceded the enactment of the Pipeline Safety Improvement Act of 2002, Senators had the following exchange regarding "related series of violations": [Sen. Hollings]: "*I am seeking clarification that all information requests issued by the Secretary pursuant to a single incident investigation are considered "related" for purposes of calculating the $1,000,000 civil penalty cap for a 'related series of violations'…" [Sen. Kerry]: "it is the intention of this legislation to treat all information requests pursuant to a single incident investigation as 'related' for purposes of applying the civil penalty cap…*" *Exhibit 81,* Senator Hollings (SC) and Senator Kerry (MA). "Pipeline Safety Improvement Act." Congressional Record 146:103 (Sept. 7, 2000), p. S8235.

B. Any Penalty Must Consider All Mitigating Factors

In addition to the above, the proposed penalty fails to account for relevant statutory mitigation factors required under the Pipeline Safety Act, including good faith and cooperation. *49 U.S.C. § 60122(b); 49 C.F.R. Part 190.225*. In assessing a penalty, the Agency must ("shall") consider the nature of the violation, circumstances, gravity, culpability and good faith in attempting to achieve compliance. *Id.* The Agency's PSVR failed to appropriately apply these factors, however, despite evidence in the record demonstrating that Respondent clearly complied with applicable regulatory requirements under IMP and did not at any time make conscious decisions to disregard the law.

In addition, the proposed penalty does not appear to consider the fact that Respondent was prompt, diligent and thorough in responding to and investigating the incident. The Agency acknowledges this fact in the PSVR. *Exhibit B to PHMSA PSVR, CPF 4-2013-5027 (Accident Report), pp. 11, 14* (noting that Respondent's response to the incident was timely, appropriate and in accordance with its procedures). To date, Respondent has spent over $75 million in response to the Mayflower incident and continues to review and revise its procedures in consideration of its incident investigation.

Finally, the proposed penalty should be reduced because PHMSA failed to expressly allege multi-day or statutory maximum claims in the NOPV in violation of due process and procedural requirements of the Administrative Procedure Act (APA). The APA requires that respondents in any enforcement proceeding be informed of the "matters of fact and law asserted." *5 U.S.C. 554(b).* This should include a clear statement of the theory on which the agency will proceed with its case, such that respondent can understand the issues and is afforded full opportunity to present its defense at a hearing. *Yellow Freight System v. Martin, 954 F.2d 353, 357 (6th Cir. 1992).* PHMSA's NOPV fails to satisfy these basic requirements because it does not provide any explanation of how the penalty was derived, including whether it alleges multi-day or statutory maximum claims. The proposed penalty should be reduced accordingly, as a matter of equity, policy, and in light of due process considerations.

For all of the reasons noted above, the proposed penalty should be significantly reduced.

V. The Compliance Order is Overbroad and Unnecessary

The Proposed Compliance Order (PCO) should be withdrawn because Respondent complied with the IMP regulations, thus there is no basis for a finding of violation that would allow issues of a PCO. In addition, the PCO is both overbroad and unnecessary and, as such, constitutes an abuse of agency discretion.

The PCO directs Respondent to undertake activities on "all assets," not just the Pegasus Pipeline. There is no authority under the PSA or the Agency's rules to apply incident-specific corrective actions in a NOPV to other company assets.[18] In addition, established federal case law requires

[18] At the Hearing, PHMSA incorrectly estimated that 80% of ExxonMobil Pipeline Company and Mobil Pipeline Company assets are pre-1970 ERW. *Transcript, p. 154, lines 14-15*. In actuality, the companies own or operate pipelines consisting of roughly 50% of LF-ERW pipe.

that injunctive relief be narrowly tailored to the specific harm alleged (not potential harm) and that an overboard scope of injunctive relief is an abuse of discretion. *Ahearn ex rel. N.L.R.B. v. Remington Lodging & Hospitality, 842 F.Supp.2d 1186, 1205-06 (D. Alaska 2012) (appeal dismissed Apr. 6, 2012) citing Stormans, Inc. v. Selecky, 586 F.3d 1109, 1140 (9th Cir. 2009).* Yet, the PCO does just that. *PCO, Paragraph 1* (requiring review and revision of the Company's IMP Plan for "all pre-70 ERW pipe *on any assets covered by the operator's IMP*") (emphasis added).

In addition, the PCO is unnecessary. The IMP regulations require continual evaluation of risk to a pipeline's integrity, regardless of whether incidents have occurred or violations are alleged. *49 C.F.R. Part 195.452(j)*. For this reason, and as a prudent operator, Respondent has already begun work on virtually all actions addressed in the PCO and expects to address all of the elements of the PCO.[19]

In light of the above, the PCO should be withdrawn or, at a minimum, modified to tailor the corrective actions to the assets at issue.

VI. Summary and Request for Relief

PHMSA closely audited the Pegasus Pipeline in 2007, including a specific and intensive review of Respondent's seam failure engineering analyses. Despite four PHMSA inspectors spending a full week on the review, the Agency did not find *any* flaws in the Respondent's IMP plan or implementation of its LF-ERW seam risk process. Even after the 2013 incident, the nation's leading experts in LF-ERW threat analysis and pipeline risk management who submitted affidavits for this matter concluded the Mayflower incident was not capable of either prediction or reliable detection using existing technology and methods. The Agency's own most recent Battelle report on ERW pipe risk generally, commissioned by PHMSA at the repeated request of NTSB and issued *after* this incident, similarly concluded that technology is not yet capable of finding such unusual anomalies as that causing the Mayflower incident. That conclusion is in stark contrast to the NOPV's bold after the fact assertion that "*there was more than adequate information*" to conclude that a specific risk existed. The record reveals that the anomaly causing this incident was not capable of prediction or reliable detection by technology and methods of inspection used at the time in compliance with applicable law. Moreover, Respondent not only complied with applicable law in considering the risk of seam failure, it actually did *more* than what is legally required regarding consideration of the risk of LF-ERW seam failure.

The Agency has issued relatively little regulation or guidance over the years on how to consider or identify the risk of LF-ERW seam failure. Despite this lack of direction, Respondent clearly did have a written IMP Plan in place that carefully considered the risk of seam failure of its LF-ERW pipe, in compliance with the minimal legal requirements and PHMSA guidance available, and consistent with industry standards on this issue. In fact, Respondent reviewed the risk of seam failure numerous times, over many years, using dozens of in-house and consulting engineers to review the data, analyses and conclusions. Three separate hydrotests were

[19] In addition, the timeframes set forth in the PCO, including Paragraph 1, are both unreasonable and unworkable.

performed, along with three ILI runs (one being a seam/crack tool), and four separate seam failure engineering analyses.

The alleged violations in Items 1 – 4 and 7 of the NOPV are unsupported by the record in this case because they presume a failure to conduct a seam analysis, which is controverted by the facts. In addition, there are errors and inconsistencies in the NOPV which were not explained by the Agency in the Hearing. In light of such errors, Items 5, 6, 8 and 9 go unsupported by the evidence. Item 8 should also be dismissed for failure to state a claim, because it asserts a violation of the Agency's O&M program rules, but discusses facts related to the Agency's IMP rules.

Even if the alleged violations were proved, the amount of penalty proposed should be significantly reduced. Items 1 – 4 and 7 are a "related series of violations" for penalty purposes, meaning they should be combined to a single claim and then subject to the statutory penalty cap. The Agency also failed to apply mitigating factors required by the statute in proposing a penalty.

Finally, the PCO is both illegally overbroad, and unnecessary, in light of the fact that existing IMP regulations require such 'continual evaluation' of risk factors and analyses proposed in the Compliance Order.

For all of these reasons, and in consideration of other matters as justice may require, the NOPV (including the Proposed Civil Penalty and the Proposed Compliance Order), should be withdrawn in its entirety. In the alternative, the claims asserted should be revised, the penalty substantially reduced and the Compliance Order substantially modified.

Respectfully submitted,

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Date: July 25, 2014

Index of Attached Exhibits[20]

No.	Exhibit
57	EMPCo IMP Manual, Appendix K, Validation and Repair Process (2010)
58	EMPCo IMP Manual, Sections 2.3.5.4.2-4 (Safety-Related Condition Requirements) (2010)
59	EMPCo Email from C. Gorman to IMP team (Jan. 10, 2011)
60	EMPCo Email from M. Weesner approving OIMS 2A Attachment #7 (Mar. 15, 2011)
61	EMPCo Email from L. Lamons to J. Johnson (GE PII) (Nov. 29, 2012)
62	EMPCo Email from C. Gorman to R. Coryell (GE PII) (Dec. 3, 2012)
63	EMPCo Email from C. Gorman to B. Hagerman (GE PII) (Mar. 15, 2013)
64	GE PII Email from J. Johnson to P. Vocke (EMPCo) (Apr. 12, 2012)

[20] The Exhibit references set forth in this Index continue from the Hearing Exhibits referenced and included with Respondent's Pre-Hearing Brief and discussed at the Hearing.

Index of Exhibits Included by Reference[21]

No.	Exhibit
65	Battelle Institute, "Final Interim Report" on ERW Seam Failures (Sept. 20, 2012)
66	Battelle Final Summary Report on ERW Seam Failures (Oct. 23, 2013)
67	Battelle ERW Study, 12th Quarterly Report (May 31, 2014)
68	NTSB Accident Report (Carmichael, MS), NTSB/PAR-09/01 (Nov. 1, 2007)
69	NTSB Safety Recommendation to PHMSA (Oct. 27, 2009)
70	NTSB Letter to PHMSA (Dec. 29, 2010)
71	NTSB Letter to PHMSA (Oct. 19, 2011)
72	OPS Alert ALN-88-01 (Jan. 28, 1988)
73	OPS Alert ALN-89-01 (Mar. 8, 1989)
74	OPS Final Rule, 59 Fed. Reg. 29379 (June 7, 1994)
75	OPS Final Rule, 65 Fed. Reg. 75378 (Dec. 1, 2000)
76	PHMSA Final Order, In re Rocky Mountain Pipeline System, LLC, CPF 5-2004-5001 (Dec. 11, 2006)
77	PHMSA Final Order, In re: Colorado Interstate Gas Co., PHMSA CPF 5-2008-1005 (Nov. 23, 2009)
78	PHMSA Final Order, In re: ExxonMobil Pipeline Company, PHMSA CPF 4-2011-5016 (Jun. 27, 2013)
79	PHMSA Liquid IMP Frequently Asked Question (FAQ) 7.19
80	PHMSA Notice of Amendment, In re Cenex Pipeline Company, PHMSA CPF 5-2011-5018M (July 26, 2011)
81	"Pipeline Safety Improvement Act," Congressional Record 146:103 (testimony of Senator Hollings and Senator Kerry) (Sept. 7, 2000)

[21] These documents should be considered part of the record in this matter, but they have not been attached with this submission because they are publically available.