U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

12300 W. Dakota Ave., Suite 340
Lakewood, CO 80228

NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: bill.johnson@p66.com

March 26, 2026

Mr. William Johnson
President
Phillips 66 Pipeline LLC
2331 Citywest Blvd.
Houston, TX 77042

CPF 5-2026-006-NOPV

Dear Mr. Johnson:

From August 26 to October 23, 2025 representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code (U.S.C.) inspected Phillips 66 Pipeline LLC's (P66) Borger to Denver and Borger to Amarillo (BDAM) pipeline system, from Borger, Texas, to Denver, Colorado, and Amarillo, Texas, respectively. The BDAM consists of the following three mainlines: the 8-inch and 12-inch Borger to Denver mainline (BD-01), the 8-inch Borger to Amarillo mainline (AM-08), and the 10-inch Borger to Amarillo mainline (AM-10).

As a result of the inspection, it is alleged that P66 has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The items inspected and the probable violations are:

1. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . .
(c) ***What must be in the baseline assessment plan? –***

(1) An operator must include each of the following elements in its written baseline assessment plan:
(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by in-line inspection tool(s) described in paragraph (c)(1)(i)(A) of this section for the range of relevant threats to the pipeline segment. If it is impracticable based upon the construction of the pipeline (e.g., diameter changes, sharp bends, and elbows) or operational limits including operating pressure, low flow, pipeline length, or availability of in-line inspection tool technology for the pipe diameter, then the operator must use the appropriate method(s) in paragraphs (c)(1)(i)(B), (C), or (D) of this section for the range of relevant threats to the pipeline segment. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in § 195.106(e) or lap-welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies.
(A) In-line inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. For pipeline segments with an identified or probable risk or threat related to cracks (such as at pipe body or weld seams) based on the risk factors specified in paragraph (e), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an in-line inspection tool, an operator must comply with § 195.591. An operator using this method must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies;

P66 failed to conduct baseline integrity assessments for the range of relevant threats to the BDAM, as required.[1] Section 195.452(c)(1)(i)(A) requires that for pipeline segments located in an high consequence area (HCA) or in a could affect HCA with an identified or probable risk or threat related to cracks, operators must use an in-line inspection tool or tools capable of detecting crack anomalies. During the inspection, PHMSA found evidence of identified or probable risk or threat related to cracks on multiple pipeline segments of the BDAM. A review of P66's records indicated P66 identified cracking as the primary threat on numerous pipeline segments, including the 10-inch AM-10 mainline. However, P66 failed to identify cracking as a threat on other pipeline segments with similar pipeline characteristics operating above 60% of specified minimum yield strength (SMYS), such as the 8-inch AM-08 mainline.

In addition, P66 classified numerous pipeline segments with a baseline susceptibility for both the long seam cracking threat and the stress corrosion cracking (SCC) threat. However, during the PHMSA inspection, a review of P66's Crack Management Program (CMP) found the Baseline Screening Process section for both susceptibility to long seam cracking failure and SCC failed to identify pipeline segments considered susceptible to the cracking threat and thereby failed to schedule a baseline in-line inspection capable of detecting crack anomalies as required by §

[1] The P66 BDAM includes pipeline segments that could affect a high-consequence area (HCA), as defined per 49 CFR § 195.450 and Appendix C to Part 195.

195.452(c)(1)(i)(A).[2] Further, P66's Appx 04B Long Seam Cracking Baseline Assessment Flowchart permits pipeline segments with susceptibility to the long seam cracking threat to not undergo a baseline crack assessment. Similarly, P66's IP-004 Appendix C Stress Corrosion Cracking Baseline Assessment Flowchart permits pipeline segments with susceptibility to the SCC threat to not undergo a baseline crack assessment. PHMSA also observed that the Baseline Screening Process section allowed the Asset Integrity Team to use engineering judgement to justify a baseline crack assessment for pipelines not meeting the requirements for either a long seam cracking or SCC baseline assessment. However, engineering basis is only permitted for variance from the 5-year reassessment interval in limited situations, not for the baseline assessment.[3]

A review of P66's repair notes found cracks, crack-like features, or dents with internal linear indications on numerous pipeline segments, such as the 8-inch Mckee to milepost (MP) 52 segment, the 8-inch MP 136 to Ninaview segment, the 8-inch MP 190 to La Junta segment, the 8-inch La Junta to Rush segment, and the 8-inch Rush to Kiowa pipeline segment. Internal linear indications, while not conclusive determinations, demonstrate a probable risk of cracks being present on the pipeline segments.

Moreover, P66 identified locations with SCC risk factors based on pipeline characteristics, failure history, and environmental conditions.[4] Specifically, the 12-inch BD-01 replacement segments were constructed between 1985 and 1987, were operated above 60% of SMYS, and had either tape or coal tar coating. Also, the 8-inch AM-08 mainline was constructed in 1958, was operated above 60% SMYS, and had either tape or coal tar coating. In addition, the 10-inch AM-10 mainline was constructed in 1990, was operated above 60% SMYS, and had either tape or coal tar coating.

Further, a review of P66's records found that in 2000, a pipe seam failure occurred near MP 254 on the 8-inch Rush to Denver Terminal pipeline segment due to a crack-like defect within the electric resistance welded (ERW) seam. In addition, in 2004, a seam failure occurred during a surge event near MP 209 on the 8-inch La Junta to Rush pipeline segment. A review of the corresponding failure report found that pressure surges contributed to the seam split.

However, a review of P66's records during the PHMSA inspection revealed that P66 only ran crack detection tools on the original 8-inch BD-01 segments of the BDAM and not the following pipeline segments located in an HCA or in a could affect HCA:

- 12-inch BD-01 replacement pipeline segments, including:
    - 12-inch Borger to Mckee (37.4 total miles; 14.9 HCA miles)
    - 12-inch Boise City to MP 114 (14.8 total miles; 3.3 HCA miles)
- 8-inch AM-08 mainline (46.8 total miles; 16.3 HCA miles)

[2] For example, NACE SP0204-2015 specifies that a pipeline segment is considered susceptible to SCC if all the following susceptibility criteria are met: the operating stress exceeds 60% of SMYS, the age of the pipeline is greater than 10 years, and the coating type consists of a material other than plant-applied or field-applied fusion-bonded epoxy (FBE) or liquid epoxy (when abrasive surface preparation was used during field coating application).

[3] See § 195.452(j)(4)(i).

[4] See § 195.452(e).

- 10-inch AM-10 mainline (46.8 total miles; 16.6 HCA miles)

Therefore, P66 failed to conduct a baseline assessment for the range of relevant threats to the pipeline segments of the BDAM located in an HCA or in a could affect HCA in accordance with § 195.452(c)(1)(i)(A).

2. § 195.452 Pipeline integrity management in high consequence areas.

> **(a) . . .**
> **(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity? –***
> **(1) …**
> **(4) *Variance from the 5-year intervals in limited situations –***
> **(i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.**

P66 failed to notify PHMSA 270 days before the end of the five-year interval of the justification for a longer interval based on engineering basis, and failed to propose an alternative interval for continual evaluation and assessment of the pipeline's integrity, for numerous pipeline segments identified on BDAM, as required by § 195.452(j)(4)(i).

Specifically, a review of P66's records during the PHMSA inspection found that P66 had determined integrity assessment intervals greater than five years for multiple segments of the BDAM. However, P66 had not notified PHMSA at least 270 days prior to the end of the five-year reassessment intervals to justify the extended assessment periods for the following pipeline segments on the BD-01:

- 8-inch Mckee to MP 52 (15.3 total miles; 0.42 HCA miles) with a crack reassessment interval of 16.3 years
- 8-inch MP 136 to Ninaview (38.4 total miles; 0.4 HCA miles) with a crack reassessment interval of 22 years
- 8-inch MP 190 to La Junta (13.9 total miles; 4.1 HCA miles) with a crack reassessment interval of 15 years
- 8-inch La Junta to Rush (66.9 total miles; 23.4 HCA miles) with a crack reassessment interval of 10 years
- 8-inch Kiowa to Denver Terminal (36 total miles; 23.7 HCA miles) with a crack reassessment interval of 35 years

Except for the 8-inch Rush to Kiowa segment, which has a crack reassessment interval of 5 years, all the 8-inch BD-01 pipeline segments have crack reassessment intervals of 5 years or more. This deviates from the minimum 5-year interval required by § 195.452(j)(3) for segments located in an HCA or in a could affect HCA. P66's records justified the longer intervals with an engineering basis of a Pressure Cycle Fatigue Analysis (PCFA), which is permitted in limited situations, however, P66 could not provide any records to demonstrate P66 had notified PHMSA 270 days before the end of the five-year interval of this analysis and justification for a longer interval.

Therefore, P66 failed to notify PHMSA 270 days before the end of the five-year interval of the justification for a longer interval for multiple pipeline segments of the BDAM located in an HCA or in a could affect HCA in accordance with § 195.452(j)(4)(i).

3. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . .
(j) ***What is a continual process of evaluation and assessment to maintain a pipeline's integrity? –***
(1) …
(3) *Assessment intervals.* **An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.**

P66 failed to base its pipeline integrity assessment intervals on the risk the line pipe posed to the HCAs to determine the priority for assessing pipeline segments on the BDAM, as required by § 195.452(j)(3). Specifically, P66 failed to base the 8-inch Kiowa to Denver pipeline segment's crack assessment interval on the risk the pipeline posed to the HCA.

During the inspection, PHMSA reviewed P66's records and found that P66 identified cracking as the primary threat on the 8-inch Kiowa to Denver pipeline segment. In addition, P66 classified this segment with a baseline susceptibility for both the SCC threat and the long seam cracking threat.

A review of P66's repair notes found cracks, crack-like features, or dents with internal linear indications on numerous pipeline segments, including the 8-inch Mckee to MP 52 segment, the 8-inch MP 136 to Ninaview segment, the 8-inch MP 190 to La Junta segment, the 8-inch La Junta to Rush segment, and the 8-inch Rush to Kiowa pipeline segment.

In addition, P66 identified locations with SCC risk factors based on pipeline characteristics, failure history, and environmental conditions. Specifically, the 8-inch Kiowa to Denver pipeline segment was constructed in 1971, operated above 60% SMYS, and had either tape or coal tar coating.

Further, as stated in Item 1, PHMSA's review found that in 2000, a pipe seam failure occurred near MP 254 on the 8-inch Rush to Denver Terminal pipeline segment due to a crack-like defect within the ERW seam. In addition, in 2004, a seam failure occurred during a surge event near MP 209 on the 8-inch La Junta to Rush pipeline segment. That failure report found pressure surges contributed to the seam split.

In addition, P66's records indicated the 8-inch Kiowa to Denver pipeline segment has the highest percentage of HCA miles (approximately 65%) of the BDAM pipeline segments and is located in heavily populated suburban and industrial areas of Denver. However, its baseline crack-detection tool assessment was performed on December 15, 2014, and no crack-detection tool reassessment has been done since that date as P66's records indicate this pipeline segment was given a 35 year reassessment interval.

Therefore, P66 failed to base its assessment intervals on the risk the line pipe posed to the HCA to determine the priority for assessing crack-susceptible pipeline segments on the BDAM, as required by § 195.452(j)(3).

4. § 195.416 Pipeline assessments.

> **(a) . . .**
> **(b) *General*. An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029, and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.**

P66 failed to determine periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment, as required by § 195.416(b).[5] Specifically, a review of P66's records during the PHMSA inspection found that P66 had determined the periodic

[5] Section 195.416(b) also requires operators to perform initial assessments on non-HCA segments by October 1, 2029. A review of P66's records during the PHMSA inspection found that the 12-inch MP 52 to MP 67 segment, the 12-inch Campo to MP 136 segment, and the 12-inch Ninaview to MP 190 segment had not been scheduled for an initial assessment yet. PHMSA notes that these pipeline segments must have its initial assessments performed by October 1, 2029.

reassessment intervals for the following pipeline segments not located in an HCA or in a could affect HCA (non-HCA segments)[6] on the BD-01:

- 8-inch MP 67 to Boise City (31.6 total miles; 0 HCA miles) with a crack reassessment interval of 15 years
- 8-inch MP 114 to Campo (12.9 total miles; 0 HCA miles) with a crack reassessment interval of 114 years

The 8-inch MP 67 to Boise City's crack baseline assessment was performed on December 1, 2017. Therefore, the reassessment for this pipeline segment should be calendar year 2027, as required by § 195.416(b), not calendar year 2032.[7] Further, the 8-inch MP 114 to Campo's crack baseline assessment was performed on December 16, 2016. A reassessment interval of once every 10 years would mean the next assessment should occur in calendar year 2026 not 2130, as noted in P66's records.

Therefore, P66 failed to determine periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment, as required by § 195.416(b).

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $272,926 per violation per day the violation persists, up to a maximum of $2,729,245 for a related series of violations. For violation occurring on or after December 28, 2023 and before December 30, 2024, the maximum penalty may not exceed $266,015 per violation per day the violation persists, up to a maximum of $2,660,135 for a related series of violations. For violation occurring on or after January 6, 2023 and before December 28, 2023, the maximum penalty may not exceed $257,664 per violation per day the violation persists, up to a maximum of $2,576,627 for a related series of violations. For violation occurring on or after March 21, 2022 and before January 6, 2023, the maximum penalty may not exceed $239,142 per violation per day the violation persists, up to a maximum of $2,391,412 for a related series of violations. For violation occurring on or after May 3, 2021 and before March 21, 2022, the maximum penalty may not exceed $225,134 per violation per day the violation persists, up to a maximum of $2,251,334 for a related series of violations. For violation occurring on or after January 11, 2021 and before May 3, 2021, the maximum penalty may not exceed $222,504 per violation per day the violation persists, up to a maximum of $2,225,034 for a related series of violations. For violation occurring on or after July 31, 2019 and before January 11, 2021, the maximum penalty may not exceed $218,647 per violation per day the violation persists, up to a maximum of $2,186,465 for a related series of violations.

[6] Section 195.416 applies to non-HCA segments not subject to the integrity management requirements in § 195.452, as stated in §195.416(a).

[7] Section 195.416(c) requires operators to use appropriate in-line inspection tool(s) for the range of relevant threats being assessed, including the cracking threat. In addition, § 195.416(d) permits operators to use other technologies if the operator can demonstrate the technology can provide an equivalent understanding of the condition of the line pipe for threat being assessed. An operator choosing this option must notify OPS 90 days before conducting the assessment.

We have reviewed the circumstances and supporting documents involved in this case, and have decided not to propose a civil penalty assessment at this time.

Proposed Compliance Order
With respect to Item 1 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to P66. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Warning Items
With respect to Items 2, 3, and 4, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these items. Failure to do so may result in additional enforcement action.

Response to this Notice
Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Enforcement Proceedings*. Please refer to this document and note the response options. All material you submit in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. §552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following your receipt of this Notice, you have 30 days to respond as described in the enclosed *Response Options*. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order. If you are responding to this Notice, we propose that you submit your correspondence to my office within 30 days from receipt of this Notice. The Region Director may extend the period for responding upon a written request timely submitted demonstrating good cause for an extension.

In your correspondence on this matter, please refer to **CPF 5-2026-006-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

For Dustin Hubbard
Director, Western Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 J. Luo (#25-329421)
Jeff Shouse, Director DOT Liquid Operations Compliance, jeff.d.shouse@p66.com
Doug Sauer, Manager Pipeline Regulatory Affairs, doug.b.sauer@p66.com
Brennon Blevins, DOT Coordinator, brennon.d.blevins@p66.com

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Enforcement Proceedings

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to P66 a Compliance Order incorporating the following remedial requirements to ensure the compliance of P66 with the pipeline safety regulations:

A. In regard to Item 1 of the Notice pertaining to integrity baseline assessments:

1. P66 must create and submit amended written procedures that properly identifies pipeline segments with an identified or probable risk or threat related to cracks, so that those pipeline segments can be scheduled for a baseline crack assessment capable of detecting crack anomalies. The amended procedures must be submitted to the Director, Western Region, for review and approval within **30** days of receipt of the Final Order.

2. P66 must create a plan and schedule to assess the pipelines on the BDAM with in-line-inspection tool(s) capable of detecting cracks or crack-like flaws in the pipe body, and girth and long seam welds, and submit the plan and schedule to the Director, Western Region for review and approval within **30** days of receipt of the Final Order. For HCA segments (e.g., the 12-inch Borger to Mckee or 8-inch AM-08), the baseline crack assessment should be scheduled within **180** days from the receipt of the Final Order.

B. It is requested (not mandated) that P66 maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Dustin Hubbard, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.