NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

VIA ELECTRONIC MAIL TO: Steve.Ledbetter@hfsinclair.com

February 2, 2024

Steven Ledbetter
Executive Vice President
Osage Pipe Line Company, LLC
2828 N. Harwood
Suite 1300
Dallas, TX 75201

CPF 4-2024-010-NOPV

Dear Mr. Ledbetter:

On August 4, 2022, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.) investigated the Osage Pipeline System in Payne County, Oklahoma, operated by Osage Pipe Line Company, LLC, a subsidiary of Holly Energy Partners, L.P.

On July 8, 2022, at approximately 12:29 a.m. Central Standard Time (CT), the Osage Pipeline System ruptured at MP 6.99 in Payne County, Oklahoma. Osage discharged an estimated 7,110 barrels of crude oil onto land belonging to the Sac and Fox Nation. The crude oil migrated from land to Skull Creek, a tributary to the Cimarron River, and traveled 0.75 miles down the creek. The crude oil release contaminated soil and surface water and impacted wildlife, including fish, birds, and terrestrial animals.[1]

As a result of the investigation, it is alleged that you have committed a probable violation of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The item investigated and the probable violation is:

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[1] As a result of the rupture, PHMSA issued a Notice of Proposed Safety Order which was resolved in a Consent Agreement and Order. *See* Osage Pipe Line Company, LLC, Consent Agreement and Order, CPF No. 4-2022-055-NOPSO, 2022 WL 16900267 (Oct. 19, 2022).

1. § 195.446 Control room management.

(a) *General.* This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. The procedures required by this section must be integrated, as appropriate, with the operator's written procedures required by § 195.402. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

Osage Pipe Line Company, LLC (Osage) failed to follow its written control room management procedures in accordance with § 195.446(a). Specifically, Osage's controller and control room supervisor attempted to restart a pipeline after receiving multiple leak alarms before assuring segment integrity and determining if a leak occurred, contrary to Osage's written control room management procedures. This failure increased the severity of the July 8, 2022, accident.

At the time of the rupture, the Osage Pipeline System was under the primary control of a controller in Artesia, New Mexico. This location is the Primary Control Center (PCC) for Osage. Osage's PCC is composed of five continuously monitored consoles, and typically has a Control Center Shift Foreman (CCSF) or Senior Controller (SC) that can monitor all consoles and assumes control during controller breaks. The Osage Pipeline is one of the pipelines that Console 4 is responsible for controlling.

In its *Control Room Management Procedure*, Revision 11.0, effective 12/20/2021, Osage specified the required actions of a controller when a leak is suspected. Sections 17.7.1 and 17.9.2 both require shut-ins if any condition appears that could indicate a leak, and that the pipeline cannot be returned to service until segment integrity is assured and the pressure variance is explained.

As indicated in the timeline below, beginning at 12:29 a.m. CT on July 8, 2022, the Console 4 Controller received at least four indications a potential leak had occurred (Potential Indication), including a detected loss of suction pressure at two pump stations that caused an automatic shutdown of the pumps and two leak alarms. Despite these indications, the Console 4 Controller, with CCSF approval, attempted to restart a pump station on the Osage pipeline after the second leak alarm without assuring segment integrity and determining the cause of the pressure variance, such as by thoroughly investigating line balance, flow trends, rate of change, status of suppliers, and other factors associated with pipeline conditions. After the Console 4 Controller attempted to restart the upstream pump station, a third leak alarm occurred, causing the Console 4 Controller to shut down the Osage pipeline. The attempted restart, prior to assuring segment integrity, increased the volume of crude oil released and violated sections 17.7.1 and 17.9.2 of Osage's control room management procedures.

These failures are detailed in the following timeline:

- At 12:19 a.m. CT, the Console 4 Controller logged a regular break. Shortly after, the CCSF became suddenly ill and left the control room without notifying any other controllers that were working at other consoles. As a result, Console 4 was left un-monitored.

- At 12:29 a.m., the SCADA system detected a loss of suction pressure at the Cushing PS (upstream PS) which caused an alarm (Alarm 1, Potential Indication 1) and automatic shutdown of the pumps. This alarm went undetected until 12:33 a.m.

- At 12:30 a.m., a leak alarm occurred (Leak Alarm 1, Potential Indication 2) followed by the automatic shutdown of the Ralston PS (downstream PS) on a loss of suction pressure. This alarm went undetected until 12:33 a.m.

- At 12:32 a.m., the Hardy PS automatically shut down on a loss of suction pressure. This event was noted in the RCFA but was not listed as an alarm. This event went undetected until 12:33 a.m. (Potential Indication 3).

- At 12:32 a.m., the initial leak alarm returned to a normal state.[2]

- At 12:33 a.m., upon returning from a scheduled break, a SC at another console noticed Console 4 alarms and called upstream supplier checking on their status. The SC notified the supplier to shut down their booster pumps and they complied.

- At 12:35 a.m., a second leak alarm occurred (Leak Alarm 2, Potential Indication 4).

- At 12:37 a.m., Console 4 Controller and CCSF returned from breaks and were informed of the situation.

- At 12:38 a.m., Console 4 Controller acknowledged second leak alarm, which returned to a normal state.

[2] Although the leak alarm returned to a normal state, that does not mean there is no leak. The leak detection system may determine that conditions are "okay" as a result of the pumps shutting down. However, Osage's procedures require that leak alarms be presumed actual until proven otherwise. Therefore, a controller cannot assume a leak is not occurring if the leak alarm returned to a normal state as further investigation would be required.

- At 12:39 a.m., Console 4 Controller recontacted the upstream supplier asking them about a potential tank switch and received verification that there had not been a tank switch.[3] The Console 4 Controller then asked the supplier to restart their booster pump.

- At 12:40 a.m., Console 4 Controller and CCSF attempted to restart the Cushing PS. A third leak alarm activated at that time (Leak Alarm 3, Potential Indication 5).

- At 12:43 a.m., Console 4 Controller shut down the Osage pipeline and began the line block sequence.

Therefore, Osage failed to follow its written control room management procedures in accordance with § 195.446(a).

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to 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. For violation occurring on or after November 27, 2018 and before July 31, 2019, the maximum penalty may not exceed $213,268 per violation per day, with a maximum penalty not to exceed $2,132,679. For violation occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022.

We have reviewed the circumstances and supporting documentation involved for the above probable violation(s) and recommend that you be preliminarily assessed a civil penalty of $ 239,142 as follows:

Item number	PENALTY
1	$ 239,142

Response to this Notice

[3] Tank switches can often cause fluctuations in the operating conditions of a pipeline. Therefore, a tank switch could have caused the alarms if the tank switch was not communicated. Here, the controller contacted the upstream supplier to confirm that a tank switch did not occur.

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 4-2024-010-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Bryan Lethcoe
Director, Southwest Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Response Options for Pipeline Operators in Enforcement Proceedings*

cc: Ms. Lori Coupland, Vice President, Compliance and EHS, Holly Energy Partners, LP, lori.coupland@hollyenergy.com