



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

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

**NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER**

VIA ELECTRONIC MAIL TO : Martyn.Willsher@amplifyenergy.com

April 6, 2023

Mr. Martyn Willsher
President and Chief Executive Officer
Amplify Energy Corp.
111 Ocean Boulevard, Suite 1240
Long Beach, CA 90802

CPF 5-2023-025-NOPV

Dear Mr. Willsher:

From August 31, 2021 through September 3, 2021, 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.), inspected your San Pedro Bay Pipeline, a transmission line that transports crude oil from Platform Elly, located off the coast of California in Federal waters, to Beta Pump Station located onshore in the City of Long Beach, California.

This inspection, and subsequent enforcement action, is not related to the October 2, 2021 pipeline failure. PHMSA's investigation into the circumstances that led to the failure, including Beta Offshore's compliance with the Federal pipeline safety regulations, remains ongoing. The results of that investigation could lead to further administrative or judicial enforcement action.

As a result of the inspection, it is alleged that you have 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) ...

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (see paragraph (j) of this section), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Operators must continue to comply with the data integration elements specified in §195.452(g) that were in effect on October 1, 2018, until October 1, 2022. Operators must begin to integrate all the data elements specified in this section starting October 1, 2020, with all attributes integrated by October 1, 2022. This analysis must:

(1) Integrate information and attributes about the pipeline that include, but are not limited to:

- (i) Pipe diameter, wall thickness, grade, and seam type;**
 - (ii) Pipe coating, including girth weld coating;**
 - (iii) Maximum operating pressure (MOP) and temperature;**
 - (iv) Endpoints of segments that could affect high consequence areas (HCAs);**
 - (v) Hydrostatic test pressure including any test failures or leaks - if known;**
 - (vi) Location of casings and if shorted;**
 - (vii) Any in-service ruptures or leaks - including identified causes;**
 - (viii) Data gathered through integrity assessments required under this section;**
 - (ix) Close interval survey (CIS) survey results;**
 - (x) Depth of cover surveys;**
 - (xi) Corrosion protection (CP) rectifier readings;**
 - (xii) CP test point survey readings and locations;**
 - (xiii) AC/DC and foreign structure interference surveys;**
 - (xiv) Pipe coating surveys and cathodic protection surveys.**
 - (xv) Results of examinations of exposed portions of buried pipelines (i.e., pipe and pipe coating condition, see § 195.569);**
 - (xvi) Stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in-situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline;**
 - (xvii) Aerial photography;**
 - (xviii) Location of foreign line crossings;**
 - (xix) Pipe exposures resulting from repairs and encroachments;**
 - (xx) Seismicity of the area; and**
 - (xxi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this part.**
- (2) Consider information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline;**
- (3) Consider how a potential failure would affect high consequence areas, such as location of a water intake.**

(4) Identify spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of encroachment). Storing the information in a geographic information system (GIS), alone, is not sufficient. An operator must analyze for interrelationships among the data.

In periodically evaluating the integrity of each pipeline segment, Beta Offshore failed to analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Operators must begin integrating all the data elements set forth in § 195.452(g)(1)-(4) by October 2020, and must complete the integration of all the data elements by October 2022. During the inspection, conducted several months after the first October 2020 implementation deadline, PHMSA observed Beta Offshore conducting an information analysis that did not incorporate any of these new elements. A pipeline operator's ability to integrate and analyze integrity data from many sources is essential for enhanced safety and proactive integrity management.

2. § 195.573 What must I do to monitor external corrosion control?

(a) *Protected pipelines.* You must do the following to determine whether cathodic protection required by this subpart complies with §195.571:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

Beta Offshore failed to conduct tests on the San Pedro Bay Pipeline at least once each calendar year, but with intervals not exceeding 15 months, to determine whether cathodic protection (CP) complies with § 195.571. Specifically, Beta Offshore failed to take annual CP readings for three consecutive years in four specific locations on its pipeline that is coated in concrete. During the inspection, Beta Offshore informed PHMSA that the test points were paved over during a construction project in the Long Beach Dock.¹ However, Beta Offshore failed to reinstall or establish new test points in the appropriate area(s) to ensure that the pipeline had adequate CP. Beta Offshore listed the locations as “not accessible,” instead of fixing the test leads in order to perform the requisite testing.

3. § 195.573 What must I do to monitor external corrosion control?

(a) ...

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

¹ During the inspection, PHMSA observed that Beta Offshore personnel did not have the proper security access to get onto the dock as required to do pipeline surveys or ROW patrols.

Device	Check frequency
Rectifier	At least six times each calendar year, but with intervals not exceeding 2 ½ months
Reverse current switch	
Diode	
Interference bond whose failure would jeopardize structural protection	
Other interference bond	At least once each calendar year, but with intervals not exceeding 15 months.

Beta Offshore failed to electrically check each device at the requisite frequency for proper performance as required by § 195.573(c). Although Beta Offshore personnel conducted rectifier readings at the correct intervals, they failed to ensure that the readings were accurate. Specifically, Beta Offshore personnel did not use a meter to verify gauge readings; instead, they only documented what the gauge indicated on the rectifier.²

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.

² PHMSA has previously held that “...inspection of a rectifier does not simply consist of obtaining and reviewing rectifier data sent remotely; it requires an operator to periodically check and calibrate the rectifier to ensure the accuracy of the data the remote monitoring device is providing.” *In the Matter of Plains Marketing, LP*, CPF No. 2-2016-6003, 2018 WL 11260434, at *5. PHMSA enforcement guidance also notes that “remote monitoring devices which are used to read rectifiers, bonds, or test stations, must be periodically calibrated or checked for accuracy if the readings are used to meet compliance requirements and time frames.” Part 195 Corrosion Enforcement Guidance, pg. 59.

We have reviewed the circumstances and supporting documentation involved for the above probable violations and recommend that you be preliminarily assessed a civil penalty of \$58,400 as follows:

<u>Item number</u>	<u>PENALTY</u>
2	\$58,400

Proposed Compliance Order

With respect to Items 1, 2, and 3 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Beta Offshore. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

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 5-2023-025-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

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

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

cc: PHP-60 Compliance Registry
PHP-500 J. Gilliam, L. Green (#21-200502)

PROPOSED COMPLIANCE ORDER

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

- A. In regard to Item 1 of the Notice pertaining to Beta Offshore's failure to begin integrating new data elements set forth in § 195.452(g)(1)-(4) into its information analysis, Beta Offshore must develop and implement a written procedure that incorporates these new data elements into its information analysis (understanding that it need not integrate *all* of the elements set forth in § 195.452(g)(1)-(4) until October 2022) and submit the procedure to PHMSA within **180** days of receipt of the Final Order.
- B. In regard to Item 2 of the Notice pertaining to Beta Offshore's failure to take annual CP readings for three consecutive years in four specific locations on its pipeline that is paved over by concrete:
 - 1. Beta Offshore shall reinstall or establish new test points in at least two of the four previous test lead locations to ensure that the pipeline has adequate CP within **360** days of receipt of the Final Order;
 - 2. Beta shall remove the test point locations from their annual survey that are no longer accessible and add the two new locations they will establish within **360** days of receipt of the Final Order;
 - 3. Beta Offshore must conduct a close interval survey (CIS) of the entire onshore portion of the San Pedro Bay Pipeline at a minimum three foot spacing to verify that adequate CP has been maintained on the pipeline within **180** days of receipt of the Final Order; and
 - 4. Beta Offshore must provide to the Director, Western Region, a copy of all test results from the CIS within **60** days of completing the CIS.
- C. In regard to Item 3 of the Notice pertaining to Beta Offshore's failure to electrically check each device at the requisite frequency for proper performance as required by § 195.573(c), Beta Offshore must establish and submit to PHMSA a procedure and process for performing electrical checks of the rectifier with a trained technician from NACE or AMPP within **90** days of receipt of the Final Order.
- D. It is requested (not mandated) that Beta Offshore 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.