NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: Massimo.insulla@eni.com

December 27, 2023

Mr. Massimo Insulla
President, CEO
Eni US Operating Co., Inc.
1200 Smith St., Suite 1700
Houston, TX 77002

CPF 5-2023-019-NOPV

Dear Mr. Insulla:

From April 25 through April 29, 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.), inspected your Nikaitchuq assets in Prudhoe Bay, Alaska.

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

1. § 195.310 Records.

(a) . . . .
(b) The record required by paragraph (a) of this section must include:
(1) . . . .
(2) Test instrument calibration data;

(4) The date and time of the test;
(7) A description of the facility tested and the test apparatus;

ENI US Operating Co., Inc. (ENI) failed to maintain proper documentation of a hydrotest performed in 2021. Exhibit H-1 to this NOPV is a record of the hydrotest titled D2P03 SID Subsea Diesel Line DOT Hydro 2021 completed by Udelhoven Oilfield System Services Inc. (UOSS). The Pipe Test Record (on page 27 of Exhibit H-1), showed that a gauge titled Crystal Gauge UDE7539 had a calibration due date of March 18, 2021, however, the gauge was utilized during testing to record temperature on July 8, 2021. The record reviewed did not include test instrument calibration data for Crystal Gauge UDE7539 to show that it was calibrated prior to its use on July 8, 2021. Further, on page 35 of Exhibit H-1, the Certificate of Calibration, identified Asset No. UDE7539s having a Serial No. of 567539, however page 27 of Exhibit H-1 identified the same gauge as having a serial number of UDE7539/000273. The serial numbers did not match between records, and it cannot be verified whether the gauge used in the hydrotest was calibrated.

In addition, page 8 of Exhibit H-1 indicated that blinds for Lockout Tag No. 34837 through No. 34844 were installed on July 9, 2021, and removed on July 8, 2021, however the test was completed July 8, 2021. The blinds were installed to isolate the portion of the pipeline that was being hydrotested. The order of events documented by the records did not outline a sensible order of these events. The operator either didn't describe their blind installation and lock-out/tag-out system correctly or the incorrect dates of blind installation were recorded. The operator wouldn't have been able to test the pipeline without the blinds installed to isolate that section of the pipeline.

Finally, page 27 of Exhibit H-1showed the foreman of the hydrotest and the UOSS Inspector signed for the Spy Island Drilling (SID) segment of the test on July 9, 2021, but the test was conducted and completed on July 8, 2021.

2. § 195.402 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

The required review of the O&M manual was inadequately documented. Some procedures documented revision numbers and dates; however several instances were discovered where signature blocks indicating acceptance of revised procedures were not completed by the required personnel.

For example, shown in Exhibit B-4, a review of a procedure titled DOT Work Ticket, was

completed on January 7, 2022. Exhibit B-4, Page 7/38, Certification of Procedure, demonstrated revision 01 was issued for use, however the signatures and dates for approval from the Maintenance Supervisor (David Coombes and Rick Kennedy), Production Superintendent (Stephen Dexheimer and Dan Lyden), and Maintenance Manager (Francesco Pitzailis) were absent. Exhibit B-4, Page 3/36, KPP01 Shutdown Valve, SDV-12021 Semi-Annual DOT PM Procedure was not signed, dated, and approved prior to use in the field. The procedure's inadequacy and lack of review was evidenced on Pages 21 through 25 out of 36 of Exhibit B-4. These procedural steps had both inserted text and handwritten notes entered into the "Action" columns, while other text was crossed out, indicating the procedure was a draft and not a finalized procedure. ENI did not provide an adequate procedure for field personnel to follow as evidenced in Exhibit B-4.

3. § 195.420 Valve maintenance.

(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

ENI failed to maintain each valve that is necessary for the safe operation of its pipeline in good working order at all times. Specifically, the 2020 and 2021 valve inspection and maintenance records for the 10-inch Sales Oil pipeline failed to evidence that ENI performed proper valve maintenance on its pipeline on five separate occasions.

First, ENI's valve maintenance record of Shut Down Valve KPP01-SDV-12021, dated January 8, 2021 (Exhibit B-1) included a sheet labeled "Annex B", with a table labeled "Function Test and Greasing", and a column header labeled "[Check] Performed". The column was left blank indicating that no valve maintenance work was performed, despite ENI checking a box on the form stating that valve maintenance requirements were met. Without complete documentation of the work performed, valve maintenance could not be verified.

Second, ENI's valve maintenance record for Shut Down Valve KPP01-SDV-12021, dated July 5, 2021 (Exhibit B-2), similarly failed to evidence proper valve maintenance. This record included a sheet labeled "Valve and actuator Info", with a table labeled "Function Test and Greasing", and a column header labeled "[Check] Below if Performed". The column was left blank. This maintenance record did not indicate if the valve was greased or if the valve had adequate grease. Without this completed documentation, valve maintenance could not be verified.

Third, the valve maintenance record for Shut Down Valve, KPP01-SDV-12021, dated January 21, 2020 (Exhibit B-3) included a sheet labeled "Valve and actuator Info", with a table labeled "Function Test and Greasing", and a column header labeled "[Check] Below if Performed". The column was left blank. This maintenance record did not indicate the valve was greased. Without this completed documentation, valve maintenance could not be verified.

Fourth, the valve maintenance record for ENI's 2-inch Diesel pipeline, Shut Down Valve, D2P03-SDV-53601 (Exhibit C-1), dated January 10, 2021, included a sheet labeled "Valve and actuator info", with a table "Function Test and Greasing". The row labeled "Grease Valve" was

left blank. This maintenance record showed no indication the valve was greased nor that it was in an acceptable condition. Without this completed documentation, valve maintenance could not be verified.

Fifth, the valve maintenance record for Shut Down Valve, D2P03-SDV-53601, dated January 8, 2020 (Exhibit C-2) included a sheet labeled "Valve and actuator info", with a table "Function Test and Greasing". The row labeled "Grease Valve" stated [the valve] was "Not greased". This maintenance record showed no indication the valve was greased nor that it was in an acceptable condition. Without this completed documentation, valve maintenance could not be verified.

4. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .
(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:
(1) . . . .
(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure …

ENI's Sales Oil Pipeline and Nikaitchuq Diesel Pipeline are both located within high consequence areas (HCAs). ENI's integrity management program failed to include an analysis that integrated all available information about the integrity of its Sales Oil Pipeline and its Nikaitchuq Diesel Pipeline and the consequences of a failure.

Specifically, the 2021 risk analysis (Exhibit A-11) for the 10-inch Sale Oil Pipeline included outdated information in 15 areas, as follows:

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 72/158, Pipe Segment: Sales Oil Pipeline Segment 1 Internal Corrosion, row 3, Pipeline Age, stated record/score was based on "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 73/158, Pipe Segment: Sales Oil Pipeline Segment 1, Stress-Corrosion Cracking, row 7, Years Since Last Pressure Test, stated record/score was based on "greater than 5 years but less than 10 years" since the last pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 74/158, Pipe Segment: Sales Oil Pipeline Segment 1, Material Problems, row 3, Pipeline Age, stated record/score was based on "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010. Row 7, of the same page, stated record/score was based on "greater than 5 years but less

than 10 years" since the last pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 75/158, Pipe Segment: Sales Oil Pipeline Segment 1, Construction Errors, row 2, Pipeline Age, stated record/score was based on "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010. Row 6 of the same page stated that the record/score was based on "greater than 5 years but less than 10 years" since the last pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 79/158, Pipe Segment: Sales Oil Pipeline Segment 1 Natural Forces Damage, row 4, Pipeline Age, stated record/score was based on "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 84/158, Pipe Segment: Sales Oil Pipeline Segment 2, Internal-Corrosion, row 3, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 85/158, Pipe Segment: Sales Oil Pipeline Segment 2, Stress-Corrosion Cracking, row 7, Years Since Last Pressure Test, stated record/score was based on "greater than 5 years but less than 10 years" for a pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 86/158, Pipe Segment: Sales Oil Pipeline Segment 2, Material Problems, row 3, Pipeline Age, stated record/score was based on "5 Years or Less" for the age of the pipeline. The Sales Oil Pipeline was installed in 2010. The same page, row 4, Years Since Last Pressure Test, stated record/score was based on "greater than 1 year but less than 5 years" since the last pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 87/158, Pipe Segment: Sales Oil Pipeline Segment 2, Construction Errors, row 2, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010. The same page, row 6, Years Since Last Pressure Test stated, "greater than 5 years but less than 10 years". The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 91/158, Pipe Segment: Sales Oil Pipeline Segment 2, Natural Forces Damage, row 4, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 96/158, Pipe Segment: Sales Oil Pipeline Segment 3, row 3, Internal Corrosion, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 97/158, Pipe Segment: Sales Oil Pipeline Segment 3, row 7, Years Since Last Pressure Test, stated record/score was based on a "greater than 5 years but less than 10 years" since the last pressure test. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 98/158, Pipe Segment: Sales Oil Pipeline Segment 3, Materials Problems, row 3, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010. The same page, row 4, Years Since Last Pressure Test states record/score “greater than 5 years but less than 10 years”. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 99/158, Pipe Segment: Sales Oil Pipeline Segment 3, Construction Errors, row 2, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010. The same page, row 6, Years Since Last Pressure Test states record/score “greater than 5 years but less than 10 years”. The last pressure test was conducted in 2010.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 103/158, Pipe Segment: Sales Oil Pipeline Segment 3, Natural Forces Damage, row 4, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Sales Oil Pipeline was installed in 2010.

The risk analysis for ENI’s 2-inch Nikaitchuq Diesel Pipeline Risk similarly contained outdated information and therefore did not include an analysis that integrated all available information about the integrity of the pipeline and the consequences of a failure. Specifically, the records reviewed indicated outdated information was used in the risk analysis in six areas, as follows:

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 108/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Internal-Corrosion, row 3, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Nikaitchuq Diesel Pipeline was installed in 2009. The same page, row 4, Frequency of In-Line Inspection or Pressure Test for Internal Corrosion Detection, stated “greater than 2 years less than 3 years” based on the last pressure test conducted in “July 2016.” The last pressure test conducted, per Exhibit H-1, was conducted in 2021.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 109/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Stress-Corrosion Cracking, row 2, Pipeline Age, stated record/score was based on a "10 years or less" age of pipeline. The Nikaitchuq Diesel Pipeline was installed in 2009. The same page, row 7, Years Since Last Pressure Test, stated “greater than 5 years but less than 10 years” based on the last pressure test conducted in “2009”. The last pressure test conducted, per Exhibit H-1, D2P03 SID Subsea Diesel Line DOT Hydro 2021, was in 2021.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 110/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Materials Problems, row 3, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Nikaitchuq Diesel Pipeline was

installed in 2009. The same page, row 4, Years Since Last Pressure Test, stated “greater than 5 years but less than 10 years” based on the last pressure test conducted in “2009”. The last pressure test conducted, per Exhibit H-1, D2P03 SID Subsea Diesel Line DOT Hydro 2021, was in 2021.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 111/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Construction Errors, row 2, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Nikaitchuq Diesel Pipeline was installed in 2009. The same page, row 6, Years Since Last Pressure Test, stated “greater than 5 years but less than 10 years” based on the last pressure test conducted in “2009”. The last pressure test conducted, per, Exhibit H-1, D2P03 SID Subsea Diesel Line DOT Hydro 2021, was in 2021.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 113/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Excavation Damage, row 11, “Deformation ILI rool run or pressure test frequency”, stated record/score was based on a "greater than 2 years less than 3 years” based on “Pressure Test July 2016”. The last pressure test conducted, per, Exhibit H-1, D2P03 SID Subsea Diesel Line DOT Hydro 2021, was in 2021.

- Per IMP Revision 1.2 (2021 version), Exhibit A-11, on Page 115/158, Pipe Segment: 2” Nikaitchuq Diesel Pipeline, Natural Forces Damage, row 4, Pipeline Age, stated record/score was based on a "6 to 10 years" age of pipeline. The Nikaitchuq Diesel Pipeline was installed in 2009.

5. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .
(h) What actions must an operator take to address integrity issues? -
(1) *General requirements*. An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats.

ENI failed to take prompt action to address a known anomalous condition on its 10-inch Sales Oil Pipeline. Specifically, in June 2020, ENI retained Coffman Engineers to perform an Atmospheric Corrosion Inspection on its Nikaitchuq assets, which included the 10-inch Sales Oil pipeline. The Atmospheric Corrosion Inspection Report (Exhibit K-1) described the as found condition of the KPP Pig Receiver segment as follows: “[p]ipe noted to be submerged in water at

road crossing nearby the KPP Pig Receiver facility. The pipe should be removed from contact with the water, if practical." The Atmospheric Corrosion Inspection report included two photos showing that the Sales Oil pipeline was "approximately 50 percent submerged." The Atmospheric Corrosion Inspection Report included a recommendation that, "[i]f practical, remove the contact between the water and the sales oil pipeline near the KPP pig receiver module pad and include this section of pipe in NDT inspection programs, if implemented." Despite this recommendation to address a known anomalous condition, ENI could not produce any documentation to show that cathodic protection was installed on the 10-inch Sales Oil pipeline, that they inspected the submerged segment, or that they performed an evaluation of the inundated pipeline insulation. ENI could not provide evidence of evaluation or remedial action taken due to the anomalous condition discovered and documented via the official Coffman Atmospheric Corrosion Inspection Report of July 3, 2020.

6. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .
(l) What records must an operator keep to demonstrate compliance?
(1) An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At a minimum, an operator must maintain the following records for review during an inspection:
(i) . . . .
(ii) Documents to support the decisions and analyses, including any modifications, justifications, deviations and determinations made, variances, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

ENI failed to document certain decisions and analysis it made with respect to recommended preventative and mitigative measures when implementing its integrity management program. Specifically, ENI's 2018 Pipeline Integrity Evaluation for the 10-inch Sales Oil Pipeline evaluated preventive and mitigative measures (Exhibit I-1). This record included a proposal to "[i]nstall remotely controlled valves" to mitigate the amount of a possible release, and two preventative measures to "[e]stablish shorter inspection intervals" and to "[c]onduct radiography for under insulation corrosion" to prevent a possible release. Part 5 of the Pipeline Integrity Evaluation "Approval of Recommended Measures" was a form that listed the preventive and mitigative measures that were considered, evaluated, and had boxes where the reviewer was to indicate whether the measures were approved or disapproved. The indication boxes in Part 5 were blank, without comments, and no decision was documented as to whether to accept or reject the proposed measures. The form was then approved and signed without determination of recommended measures.

7. § 195.503 Definitions

Qualified means that an individual has been evaluated and can:

(a) Perform assigned covered tasks and
(b) Recognize and react to abnormal operating conditions.

ENI failed to ensure through evaluation that individuals performing covered tasks were qualified. Specifically, a valve maintenance record for Shut Down Valve, D2P03-SDV-53601, on ENI's 2-inch Diesel Pipeline (Exhibit C-1) included reference to an individual who performed the valve maintenance but was not qualified to recognize or respond to an abnormal operating condition (AOC). Valve maintenance for the 2-inch Diesel pipeline, Shut Down Valve, D2P03-SDV-53601 was considered a covered task where individuals performing the task must also be qualified to respond to any AOCs. Records did not demonstrate the individual was able to recognize or respond to an AOC while performing valve maintenance, therefore the individual was not qualified to conduct covered tasks. During the inspection, ENI produced a DOT work ticket, which stated that the "Covered Task 100.01-Abnormal conditions outside control room" (Exhibit C-1) required the performance of valve maintenance by a qualified individual. The work ticket identified the name of the individual who performed the covered task, however, the qualification records for this individual did not include a qualification for covered task 100.01-Abnormal conditions outside control room.

The Employee / Tasks Qualified table for the employee who performed the valve maintenance did not list a qualification for Covered Task 100.01-Abnormal conditions outside control room at the time the record was generated on January 11, 2021. The operator could not produce records demonstrating that the employee was qualified to respond to AOCs while conducting valve maintenance on January 10, 2021.

8. § 195.505 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:
(a) . . . .
(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

ENI used Midwest Energy Association's (MEA) Remote Evaluations procedure, Initial Qualification Methods and Records (Exhibit E-3), to complete operator qualification evaluations remotely during the coronavirus pandemic. MEA procedure for conducting remote evaluations included recommended steps that required the proctor take extensive notes indicating communication devices used, verification of audio and video quality, and verification that the employee to be qualified cannot be assisted, among other requirements. ENI qualified personnel without adequate documentation to demonstrate adherence to the MEA procedure.

Qualification records reviewed for a qualified individual did not indicate the type of communication device utilized, did not verify the quality of the audio or video, nor indicated verification that the individual being tested could not be assisted during evaluation as required by the MEA Procedure. Recordings of the evaluations conducted on June 18, 2021 were not available for PHMSA review.

9. § 195.555 What are the qualifications for supervisors?

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under § 195.402(c)(3) for which they are responsible for insuring compliance.

ENI failed to require and verify that supervisors maintained a thorough knowledge of the corrosion control procedures for which they were responsible for insuring compliance. Specifically, ENI's, DOT Pipeline O&M Manual, Section 3.1 Supervisor Training and Qualifications (Exhibit A-1) described the requirement for Facility Engineers and Maintenance Supervisors. The final paragraph of section 3.1 stated "[t]he Production Manager will sign-off that the Facility Engineer and Maintenance Supervisor has received and understands this information."

ENI's Supervisor Qualification Check Sheet, Appendix D (Exhibit E-2), was identified as the form used by the operator to verify supervisors were knowledgeable in corrosion control procedures. The form had no signature or a date for the evaluation of two supervisors.

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 violations and recommend that you be preliminarily assessed a civil penalty of $ 65,900 as follows:

Item number	PENALTY
4	$ 65,900

Proposed Compliance Order

With respect to items **3 through 9** pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to ENI. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Warning Item

With respect to items **1** and **2** 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 5-2023-019-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 M. Yeager (#22-236528)
Marty Slade, ENI Compliance Officer, Marty.Slade@eni.com
Larry Burgess, ENI SEQ Manager, Larry.Burgess@eni.com
David Hart, ENI Operations Manager, David.Hart@eni.com

PROPOSED COMPLIANCE ORDER

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

A. In regard to **3** of the Notice pertaining to the valve maintenance for the 10-inch Sales Pipeline & the 2-inch Diesel Pipeline, ENI must grease and operate each valve previously mentioned within **90** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

B. In regard to **4** of the Notice pertaining to the risk analysis for the 10-inch Sales Pipeline & the 2-inch Diesel Pipeline, ENI must update and evaluate the risk analysis within **90** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

C. In regard to **5** of the Notice pertaining to the 10-inch Sales Pipeline submerged in water, ENI must demonstrate the pipeline is protected from external corrosion within **270** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

D. In regard to **6** of the Notice pertaining to Integrity Evaluation preventative and mitigative measures review, ENI must demonstrate either acceptance or rejection of the proposed preventative and mitigative measures within **90** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

E. In regard to **7** of the Notice pertaining to an individual performing covered tasks without proper AOC qualifications, ENI must demonstrate the aforementioned individual is trained and qualified for AOCs prior to them conducting any further covered tasks, after receipt of the Final Order.

F. In regard to **8** of the Notice pertaining to verification of skills & abilities accomplished remotely, ENI must demonstrate re-evaluation of all personnel who were qualified utilizing the MEA remote evaluation method without extensive notes. ENI must review all work completed by those personnel who were qualified utilizing the MEA remote evaluation method without extensive notes. ENI must ensure when the MEA remote evaluation process is utilized the process will include extensive notes as described in the MEA EnergyU process. These actions must be completed by ENI within **90** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

G. In regard to **9** of the Notice pertaining to Supervisor's training & knowledge pertaining to corrosion control, ENI must evaluate and document all applicable supervisors have a thorough knowledge of corrosion control procedures within **90** days of receipt of the Final Order and submit documentation that this action was completed to the Western Regional Director.

H. It is requested (not mandated) that ENI 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.