NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: john.kurz@alyeska-pipeline.com

April 25, 2025

Mr. John Kurz
President and CEO
Alyeska Pipeline Service Company
PO Box 196660, MS 502
Anchorage, Alaska 99519

CPF 5-2025-010-NOPV

Dear Mr. Kurz:

From April 22 through 26, May 8 through May 10, 2024, and August 19 through 30, 2024, 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 Alyeska Pipeline Service Company's (APSC) Trans-Alaska Pipeline System (TAPS) in Alaska.

As a result of the inspections, 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. **§ 195.64 National Registry of Operators.**

(a)…
(c) Changes. Each operator must notify PHMSA electronically through the National Registry of Operators at *https://portal.phmsa.dot.gov,* of certain events.
(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:
(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

APSC failed to notify PHMSA about the construction of the Point Source Heat facility at pipeline Milepost 238 not later than 60 days prior to the start of construction. APSC personnel stated to the PHMSA inspector that the construction costs were initially budgeted to be less than $10 million but that the final costs exceeded $10 million. APSC was required to notify PHMSA as soon as there was a reasonable expectation that the project costs would exceed $10 million. In this instance, APSC began the project in 2020 and completed it in 2021, but did not notify PHMSA until May 2024, after the lack of notification was identified during the inspection.

Therefore, APSC failed to timely notify PHMSA of a construction project that cost $10 million or more, as required pursuant to § 195.64(c)(i).

2. **§ 195.262 Pumping equipment.**

(a) Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.

APSC failed to provide adequate ventilation to prevent the accumulation of hazardous vapors at the "Scraper Building" at Pump Station 1, as required. APSC personnel stated that the introduction of high vapor pressure products from upstream oil producers has resulted in additional risk of hazardous vapor exposure to personnel operating the pig trap at the Pump Station 1 Scraper Building. During the inspection PHMSA observed that, in lieu of a providing an adequate fixed ventilation system at the PS1 Scraper building, APSC's practice is to gravity-drain the pig trap into a sump tank at the building and use a temporary hood over the trap door and ventilate the hazardous vapors outdoors using fans.

APSC personnel also described how APSC has proposed to use a nitrogen purge system to force purge the pig trap with pressurized nitrogen gas to reduce the exposure of accumulated hazardous vapors to operators. However this project had not been implemented as of the August 29, 2024 on-site inspection.

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.**

APSC failed to maintain each valve that is necessary for the safe operation of the TAPS in good working order at all times.

First, PHMSA observed and photographed relief valve 35-PSV-729 at Pump Station 5 Booster Pump leaking oil from the bonnet during the on-site inspection on August 27, 2024. Records provided by APSC indicated that valve 35-PSV-729 had been replaced a month prior to the inspection due to it leaking oil from the bonnet. However at the time of the inspection the issue did not appear to be resolved.

In addition, PHMSA also reviewed APSC's records regarding valve MOV-789. On January 1, 2024 valve MOV-789 failed to open on demand, causing blocked flow into the Valdez Marine Terminal (VMT) and a full flow relief event into the VMT's relief tanks. Afterwards, APSC found that MOV-789 failed to open on demand due to failed gearing in the valve's Limitorque SMB actuator. The Limitorque SMB actuator used on valve MOV-789 is the same make and model that are widely used on TAP's mainline block valves. However, APSC has not inspected the other Limitorque SMB actuators used on its mainline block valves to detect potential latent damage in the actuator's gearing since the failure of MOV-789, but only stated that the internals SMB actuators on the mainline are inspected and maintained "approximately every 20 years."

Therefore, APSC failed to maintain TAP's valves in good working order at all times, as required.

4. § 195.428 Overpressure safety devices and overfill protection systems.

> **(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.**

APSC failed to inspect and test each pressure-limiting device, relief valve, pressure regulator, or other pressure control equipment to ensure it was functioning properly, in good mechanical condition, and adequate in capacity and reliability for its intended service at least once each calendar year at intervals not to exceed 15 months on two occasions:

> APSC's inspection records of its relief valves at the North Pole Metering Facility demonstrated that APSC failed to inspect and test three relief valves at the North Pole Metering Facility (PSV-110, PSV-120, and PSV-130) during the calendar year of 2021.

APSC had records demonstrating it had inspected and tested PSV-110, PSV-120 and PSV-130 in October 2020 and again 24 months later in October 2022, but no records for the calendar year 2021.

In addition, APSC's records indicated that ASPC failed to inspect and test each pressure regulator and other items of pressure control on their regulated breakout tanks at Pump Station 1 for the calendar years of 2021 and 2022. Work orders for inspection and testing of the pressure control system on the gas blanketing system were completed during the calendar years of 2020 and 2023, but none were completed during the calendar years of 2021 or 2022.

Therefore, APSC failed to inspect and test each pressure-limiting device, relief valve, pressure regulator, or other pressure control equipment to ensure it was functioning properly, in good mechanical condition, and is adequate from a standpoint of capacity and reliability of operation for the service in which it is used at intervals not exceeding 15 months, but at least once a calendar year, as required.

5. § 195.432 Inspection of in-service breakout tanks.

(a)…
(b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to API Std 653 (except section 6.4.3, Alternative Internal Inspection Interval) (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, its integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3). The risk-based internal inspection procedures in API Std 653, section 6.4.3 cannot be used to determine the internal inspection interval.

APSC failed to inspect the physical integrity of in-service atmospheric above ground breakout tank in accordance with API Std 653 during their 2021 inspection of Tank 130. Specifically, API Std 653 Section 4.3 requires a formal tank shell evaluation of conditions that might affect the structural integrity of the shell. This evaluation must be completed by a storage tank engineer, and the evaluation must consider all anticipated loading conditions, including nozzle loads and settlement.

APSC's historic survey data shows that the soils beneath the tank bottom have experienced significant settlement since construction. According to APSC's documentation, during the 2021 out-of-service inspection of Tank 130, APSC disconnected the tank's inlet nozzle from the 32-inch relief piping and the relief piping deflected approximately 1-inch up and 1-inch to the side of the tank nozzle. This deflection is evidence that the tank's settlement was putting significant pressure on the tank's nozzle and connected piping.

API Std 653 requires the preparation of a formal written report that is retained for the life of the tank. As such, APSC was required to have produced a formal written report of the evaluation of the tank shell and nozzle loads contemporaneous with the 2021 inspection and prior to returning the tank to service. APSC provided the PHMSA inspector a report on Tank 130 regarding this evaluation that was dated August 2024, three years after the tank's inspection, and after PHMSA's inspection had begun. In addition, the report demonstrated that tank's settlement had put unsafe levels of stress on the tanks nozzle and that the settlement had not been adequately mitigated at the time of inspection.

Therefore, APSC failed to inspect the physical integrity of Tank 130, an in-service atmospheric steel above ground breakout tank in accordance with API Std 653, as required.

6. § 195.446 Control room management.

> **(a)…**
> **(j) *Compliance and deviations*. An operator must maintain for review during inspection:**
> **(1)…**
> **(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of the pipeline facility.**

APSC failed to contemporaneously document that a deviation from its control room management procedures was necessary for the safe operation of the facility, as required. Specifically, from May 26 through 27, 2022, the control room shift supervisor was required to exceed their maximum hours without sufficient rest[1]. The control room shift supervisor may be required to act as or direct the actions of the pipeline controller on duty. This deviation was documented on October 22, 2022, almost five months after the supervisor exceeded the required shift length.

Therefore, APSC failed to adequately document a deviation from its control room management procedures was necessary for the safe operation of the facility, as required.

7. § 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:**

[1] 195.446(d)(1) requires shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(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;

APSC failed to conduct an assessment for the range of relevant threats to the TAPS. Neither APSC's baseline and continuing assessments have ever used an in-line inspection (ILI) tool capable of detecting crack anomalies. Paragraph (c)(1)(i)(A) requires that pipelines with a probable risk or threat related to cracks must be assessed using ILI tool or tools capable of detecting crack anomalies.

During the inspection PHMSA found evidence of the probable threat related to cracks. APSC's non-destructive examination data found dents with internal "linear indications." This information was found by ultrasonic inspections. While linear indications cannot be conclusively determined to be cracks without cutting out the pipe and doing an internal examination of the indicated area, findings of linear indications do demonstrate probable risk.

In addition, PHMSA reviewed documentation where APSC had identified locations with stress corrosion cracking risk factors based on pipeline and environmental conditions. Further, during the inspection, APSC acknowledged that the backpressure control valves that were installed at Valdez in approximately 1998 were installed to "reduce the risk of fatigue" from cyclic stresses due to slackline conditions at Thompson Pass (a high consequence area).

In addition, PHMSA reviewed an Integrity Assessment Plan which included a proposed ILI schedule for the calendar years of 2021 through and including 2029. The Integrity Assessment Plan proposed to run crack assessment tools in the calendar years of 2022 and 2025. However, APSC did not run such a tool in 2022 and its updated Integrity Assessment Plan for calendar year 2024 acknowledged that no prior ILI run was capable of collecting baseline crack assessment data.

Therefore, APSC failed to conduct an assessment for the range of relevant threats to the TAPS in accordance with § 195.452(c)(1)(i)(A).

8. § 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)…**
> **(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.**

APSC failed to identify spatial relationship using all available information about the integrity of the entire TAPS and analyze the data for interrelationships, as required. Specifically, during the inspection, PHMSA observed that APSC only had spatial-integrated data for short sections of the pipeline where it intended to do excavation, rather than spatial data along the entire pipeline. PHMSA observed that APSC spatially integrated data by preparing "Site Excavation and Investigation" data sheets for proposed digs sites, however, those data sheets were limited to the locations where APSC had proposed to excavate the pipeline for non-destructive examination. APSC did not have spatially integrated data for the majority of sections along TAPS where a release could potentially impact an HCA, nor did it obtain the information to do a spatial relationship analysis in areas where Site Excavation and Investigation data sheets had not been prepared.

Therefore, APSC failed to identify and analyze spatial relationships among anomalous information, as required.

9. § 195.452 Pipeline integrity management in high consequence areas.

(a)…

(i) What preventive and mitigative measures must an operator take to protect the high consequence area?

(1)…

(4) Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment that is located in, or which could affect, a high-consequence area (HCA) in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, evaluate the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain within the HCA or between the pipeline segment and the HCA it could affect, and benefits expected by reducing the spill size. An RMV installed under this paragraph (i)(4) must meet all of the other applicable requirements in this part, provided that the requirement of this sentence does not apply to gathering lines.

APSC failed to determine whether emergency flow restricting devices (EFRD) are needed on TAPS using the specific factors outlined in § 195.452(i)(4), as required. During the inspection, APSC demonstrated to PHMSA that it possessed the information on individual factors required to make the determination, such as leak detection performance data, spill plume modeling, and HCA locations. However, APSC did formally compile and evaluate these individual data points to determine whether EFRDs were required.

Therefore, APSC failed to determine whether EFRDs were needed on TAPS as required.

10. § 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained paragraphs 6.2.2, 6.2.3, 6.2.4, 6.2.5 and 6.3 in NACE SP 0169 (incorporated by reference, see § 195.3).

APSC failed to provide cathodic protection meeting criteria contained in section 6.2 or 6.3 of NACE SP 0169, as required. PHMSA reviewed APSC's "Exception Reports" which are tabulated data showing areas along TAPS that did not meet the applicable NACE SP0169 criteria for the calendar years of 2021 through and including 2023. The Reports that showed areas where pipe-to-soil potentials did not meet the required criteria, including areas that had deficient cathodic protection for consecutive years. For example areas between pipeline milepost 769 and 770 did not meet criteria in 2021, 2022, or 2023, and several areas between pipeline milepost 796 and 798 did not meet criteria in 2022 or 2023.

Therefore, APSC failed to provide cathodic protection as required pursuant to § 195.571.

11. § 195.573 What must I do to monitor external corrosion control?

> **(a)…**
> **(e) *Corrective action*. You must correct any identified deficiency in corrosion control as required by § 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under § 195.452, you must correct the deficiency as required by § 195.452(h).**

APSC failed to repair or replace the generators providing current to the Bonanza Creek cathodic protection rectifier promptly. Specifically, during the inspection PHMSA observed that the bi-Monthly rectifier monitoring reports provided by APSC showed that Bonanza Creek rectifier was monitored and found to be operating on May 8, 2022, and again on November 11, 2022, but monitoring records taken between those dates stated that the rectifier was "Off for Generator Repairs. " In addition, the cathodic protection monitoring records for 2022 stated that the "Bonanza Creek Anode flex was deenergized for the entirety of the survey season" and the cathodic protection survey found that monitoring points protected by the Bonanza Creek system did not meet criteria in 2022. In addition, field notes 2023 from the site's maintenance log stated that technicians servicing the generator found it to be non-operational and the generator was wired incorrectly to power the CP system.

APSC failed to promptly repair the CP system – allowing this segment to have insufficient cathodic protection for at least 6 months in 2022 and some period in 2023.

<u>Proposed Civil Penalty</u>
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.

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 Items 2, 5, 7, 8, and 9, pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Alyeska Pipeline Service Company. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Warning Items
With respect to Items 1, 3, 4, 6, 10, and 11, 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 5-2025-010-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. Gano (#24-298502)
Janine Boyette, APSC Sr. Compliance Manager – janine.boyette@alyeska-pipeline.com

PROPOSED COMPLIANCE ORDER

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

A. In regard to Item 2 of the Notice pertaining to the exposure of hazardous vapors to operators at the Pump Station 1 scraper building, APSC must install a forced-purge system on the pig trap within **180** days of receipt of the Final Order, and must provide to the Western Region Director photographs and as-built engineering drawings within **30** days of system's completion and commissioning.

B. In regard to Item 5 of the Notice pertaining to Tank 130's settlement putting excess stress on the tank's nozzle, Alyeska Pipeline Service Company must:
- Re-level the tank and piping in such a manner that the piping can be fitted to the tank in as close to an unstressed state as possible;
- Install an engineered foundation sufficient to mitigate the future tank settlement;
- Hydrostatically test the tank.

Alyeska Pipeline Service must complete the actions above within **365** days of receipt of the Final Order, and submit documentation of completion to the Western Region Director.

C. In regard to Item 7 of the Notice pertaining to integrity assessments, Alyeska Pipeline Service Company, within **30 days** of receipt of the Final Order, submit an plan and schedule to assess TAPS with in-line-inspection tool(s) capable of detecting cracks or crack-like flaws in the pipe body, and girth and long seam welds. If Alyeska Pipeline Service Company requires time to modify TAPS to accommodate such tool(s) (include but not limited to modifying pig traps, adding temporary pigging facilities, or adding additional pressure and flow controls to ensure adequate data collection in areas of slackline) these modifications must be described in the plan and schedule. The plan and schedule must provide for assessment as soon as practicable but not less than **365 days** from the receipt of the Final Order.

D. In regard to Item 8 of the Notice pertaining to spatial integration of integrity data, Alyeska Pipeline Service Company must:
- Spatially align the information and attributes about the pipeline including at a minimum those required under 195.452(g)(1);
- Overlay those areas with pipeline segments that could affect an HCA;
- Analyze the data for interrelationships.

Alyeska Pipeline Service Company must complete this within **180** days of receipt of the Final Order, and submit documentation of completion to the Western Region Director.

E. In regard to Item 9 of the Notice pertaining to emergency flow restricting devices, Alyeska Pipeline Service Company must make a formal, written determination of the adequacy of their ability to protect HCA's using their emergency flow restricting devices (for example, their remote gate valves) as it is currently configured. Alyeska Pipeline Service Company must compete this within **180** days of receipt of the Final Order, and submit documentation of completion to the Western Region Director.

F. It is requested (not mandated) that Alyeska Pipeline Service Company 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.