



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

1200 New Jersey Avenue, SE
Washington, DC 20590

VIA ELECTRONIC MAIL TO:

Mr. Greg Lalicker
Chief Executive Officer
Hilcorp Energy Company
1111 Travis Street
Houston, Texas 77002

CPF No. 5-2021-019-CAO

Dear Mr. Lalicker:

Enclosed please find a Corrective Action Order (CAO or Order) issued by the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, in the above-referenced case. It requires Hilcorp Alaska, LLC, (Hilcorp or Respondent), a subsidiary of Hilcorp Energy Company, to take certain corrective actions with respect to a natural gas leak on its 8-inch Middle Ground Shoal (MGS) Fuel Gas System A Pipeline (MGS-A) that failed on or about April 1, 2021, within the Upper Cook Inlet, Alaska, on a subsea segment of the MGS-A pipeline between the MGS onshore facility and "A" Platform.

Service of the CAO by e-mail is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Sincerely,

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure: CAO

cc: Ms. Linda Daugherty, Deputy Associate Administrator for Field Operations, OPS
Mr. Dustin Hubbard, Director, Western Region, OPS
Mr. David S. Wilkins, Senior Vice President, Hilcorp Alaska (via email)
Mr. Ben Wasson, Hilcorp Alaska (via email)

CONFIRMATION OF RECEIPT REQUESTED

1 Hilcorp's MGS fuel gas system provides utility gas to the offshore Platforms A and C utilizing gas from the East Cook Inlet Gas Gathering System (ECIGGS) (ECIGGS is a PHMSA-regulated natural gas transmission system). The MGS pipeline system begins at the 3-inch tie-in to the ECIGGS pipeline on Wik Road in Nikiski, Alaska. The pipeline passes through Station O (201 Meter) and the MGS onshore facility before the subsea portion to the platforms. The line includes 2-inch, 4-inch, 6-inch and 8-inch diameters. The offshore (subsea) portion the MGS fuel gas system is identified as the "A" Pipeline. The "A" Pipeline begins at the onshore facility and is routed to the "A" Platform and from the "A" Platform it is routed to the "C" Platform. The "A" Pipeline is 8-inch diameter and was converted to gas service from oil service in 2005.

determined. The Failure occurred in an ecologically sensitive area and presents a serious risk to the environment due to the presence of several endangered and threatened species.

Pursuant to 49 U.S.C. § 60117, PHMSA initiated an investigation of the Incident. The preliminary findings of the agency's ongoing investigation are as follows:

Preliminary Findings

- At approximately 4:25 PM AKDT (Alaska time), on April 1, 2021, Hilcorp determined that their 8-inch MGS-A natural gas pipeline was leaking, resulting in an ongoing release of natural gas into the waters of the Cook Inlet, Alaska. The Incident was discovered when Hilcorp was informed by a helicopter pilot in the area that gas bubbles were observed on the surface of the waters of the Cook Inlet, Alaska near an offshore platform.
- Hilcorp reported the Incident to the NRC at approximately 9:20 PM EDT (5:20 PM AKDT). As a result of the Incident, Hilcorp reduced the pressure to the pipeline from 200 psig to approximately 140 psig, with a stated to PHMSA that it intended to further reduce the pressure to 70 psig, and stated that the investigation was ongoing. Hilcorp further stated that dispatching personnel to the site was being evaluated due to safety precautions during winter conditions.
- There were no fires, injuries, fatalities, or evacuations associated with the Incident.
- The MGS-A pipeline is an 8-inch nominal diameter transmission pipeline with 0.594" wall thickness. The pipeline is Grade B seamless pipe with X-Tru Coat and one-inch concrete weight coating. The portion of the MGS-A pipeline running from the MGS shore facility to the "A Platform" and the portion running from the "A Platform" to "C" Platform were installed in 1965.
- Hilcorp Alaska, LLC (OPID: 32645), purchased oil and gas facilities located in Nikiski, Alaska from XTO Energy, Inc. (OPID: 31178), on September 1, 2015. This purchase included the MGS-A pipeline.
- The product being transported by the "A Pipeline" is transmission-quality natural gas (98.67% methane). The pipeline operates continuously and has a normal operating pressure range of 150-200 psig. The pipeline was converted from liquid service to gas service in 2005.
- Several state and federal agencies, including the Alaska Department of Environmental Conservation (ADEC) and the National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS), have expressed concerns to PHMSA regarding damage marine life in the Cook Inlet as a result of methane release into the water. The Cook Inlet is designated as an environmentally sensitive area due to the presence of several endangered marine mammals. Species

likely to be present in upper Cook Inlet include Cook Inlet beluga whale (Endangered Species Act [ESA]-listed as endangered), western Distinct Population Segment (DPS) Steller sea lion (ESA-listed as endangered), Mexico DPS humpback whale (ESA-listed as threatened), harbor seals, killer whales, Hawaii DPS humpback whales, harbor porpoise, and Dall's porpoise. The Southwest Alaska DPS Northern sea otter (ESA-listed as threatened) is known to occur in lower Cook Inlet. The discharge location is within designated Critical Habitat for Cook Inlet beluga whales. Cook Inlet beluga whales are likely utilizing offshore waters in upper Cook Inlet during winter and will concentrate near forage fish locations as those populations arrive.

- Regarding risks associated with water craft, the United States Coast Guard (USCG) estimates that the risk to life and property would likely increase as the ice dissipates. The USCG has and continues its Very High Frequency radio broadcast to mariners describing the gas leak, its location, and specific requests to mitigate the risk. At this time the USCG has not implemented a safety zone around the leak location; however, if necessary it could. An identified risk condition related to the leaking pipeline itself is that the leak could get worse and the pipeline potentially mechanically fail if the leak was caused by outside forces, e.g. vibration, vortex shedding, abrasion, excessive bending, and or rock impingement.
- PHMSA has reviewed information from Hilcorp and with various state and Federal agencies regarding the various alternatives for proposed for responding to the Failure. These alternatives include: (a) immediate repair of the *Affected Segment*; (b) continued operation of the *Affected Segment* until it can be safely repaired; and (c) shutting in the *Affected Segment* until it can be safely repaired. Hilcorp has indicated it believes the safest alternative is to continue operating the *Affected Segment*, at reduced pressure until it can be safely repaired.
- PHMSA acknowledges from assertions made by Hilcorp that immediate repair of the leak would pose an extreme risk to personnel during the current cold weather conditions where diving operations are required to access, investigate, and repair the *Affected Segment*.
- PHMSA also finds that the risks for shutting in the pipeline until it can be safely repaired include a potential crude-oil spill in Cook Inlet. According to Hilcorp, the MGS-A pipeline fuels boilers and powers the platforms. Hilcorp could not continue providing a flow of water to the crude-oil line, the MGS-B pipeline, which lies directly next to the *Affected Segment* and which could freeze during colder temperatures due to such low-or no-flow conditions. This could potentially cause a breach in the MGS-B pipeline and a potential oil spill into the waters of the Cook Inlet.
- PHMSA recognizes that the majority of the MGS pipeline system is located within the waters of the Upper Cook Inlet, which is known for extreme tides (average tides

of 20 feet, maximum tides of 35 feet, and currents in excess of 5 to 7 knots) and the presence of dynamic sea ice conditions.

- Hilcorp plans to perform a multi-beam sonar survey to locate the leak and evaluate the adjacent seabed condition on Monday April 5, 2021.
- Hilcorp has further indicated to PHMSA that the company cannot access the *Affected Segment* until the ice clears, at which time diving operations can safely be conducted to access, investigate, and repair the leak. According to Hilcorp, they will attempt to get divers in the area of the Failure by Wednesday April 7, 2021. Hilcorp has indicated that it has temporary clamps that it may utilize as a temporary repair while they prepare plans for a permanent repair. The serviceability of the pipeline will remain impaired until at least this time.
- This is the fifth leak on the MGS-A since June 2014. The four previous leaks were in June 2014, August 2014, during ice-free conditions, in December 2016 thru May 2017, in ice conditions, and in 2019 when a leak was found by divers performing an inspection of the pipeline. Four of the leaks were determined to be caused by rocks contacting the pipeline in areas where the pipeline was not continuously supported by the seabed. The leak in 2019 was caused by corrosion/weld discontinuity. The rocks contacting the pipeline deteriorated the steel pipe wall by abrasion, resulting from relative movement between the pipeline and rocks contacting the pipeline. All prior leaks were repaired by installation of bolt-on, split-sleeve clamps. The 2014 leaks were 42 yards apart, the 2016/2017 leak was approximately 2/3 mile from the previous two leaks, and the current leak is in the general vicinity of the 2014 leaks.
- Vortex-induced vibrations of subsea pipelines within the Cook Inlet have been a known integrity threat for years. Subsea pipeline operators in Cook Inlet typically monitor subsea pipelines annually to identify pipeline spans that are unsupported by the seabed and, if necessary, provide additional pipeline supports within these areas. It is believed that vortex-induced vibrations are one of the motive forces responsible for the relative movement between pipeline and rocks contacting the pipeline in areas where the pipeline is unsupported by the seabed.
- PHMSA Consent agreement (5-2017-0004S), issued to Respondent in 2017 as a result of a leak on the MGS-A pipeline, included corrective measures that required integration of ILI assessment results and sonar inspection results. The integration of data identified several locations along the *Affected Segment* that met agreed upon intervention criteria resulting in pipeline repairs or other mitigation actions. Repairs and other mitigation actions included application of a pipeline clamp, coating repairs, and pipeline protection and stabilization.
- Respondent's MGS-A pipeline is subject to the pipeline safety laws in 49 U.S.C. chapter 601 and 49 C.F.R. part 192.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of title 49, United States Code, authorizes PHMSA to determine that a pipeline facility is or would be hazardous to life, property, or the environment and if there is a likelihood of serious harm, to expeditiously order the operator of the facility to take necessary corrective action, including suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other appropriate action. An order issued expeditiously must provide an opportunity for a hearing as soon as practicable after the order is issued.

In deciding whether to issue an order, PHMSA must consider the following, if relevant: (1) the characteristics of the pipe and other equipment used in the pipeline facility, including the age, manufacture, physical properties, and method of manufacturing, constructing, or assembling the equipment; (2) the nature of the material the pipeline facility transports, the corrosive and deteriorative qualities of the material, the sequence in which the material is transported, and the pressure required for transporting the material; (3) the aspects of the area in which the pipeline facility is located, including climatic and geologic conditions and soil characteristics; (4) the proximity of the area in which the hazardous liquid pipeline facility is located to environmentally sensitive areas; (5) the population density and population and growth patterns of the area in which the pipeline facility is located; (6) any recommendation of the National Transportation Safety Board made under another law; and (7) any other factors PHMSA may consider as appropriate.

After evaluating the foregoing preliminary findings of fact, and having considered the age of the pipeline, the hazardous nature of the materials transported, the significant history of leaks associated with the MGS-A pipeline, the location of the leak in a critical habitat for endangered species, the extreme tidal influence in the waters of the Cook Inlet, the threat to commercial navigation, the design of Respondent's system that depends on continued operation of MGS-A to avoid further potential harm to the environment, and the likelihood that similar conditions conducive to vortex-induced vibrations exist on the MGS-A pipeline, I find that continued operation of the *Affected Segment*, as defined below, without corrective measures is or would be hazardous to life, property, or the environment, and that failure to issue this Order expeditiously would result in the likelihood of serious harm.

Accordingly, this Order mandating immediate corrective action is issued expeditiously without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Western Region, PHMSA. If a hearing is requested, it will be held in accordance with 49 C.F.R. § 190.211.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. Respondent will be notified of any

additional measures required and, if appropriate, PHMSA will consider amending this Order. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions

Definitions:

Affected Segment – The “*Affected Segment*” means Hilcorp’s 8-inch MGS-A pipeline between the MGS onshore facility and “A” Platform.

Director – The Director, Western Region, PHMSA, OPS, 12300 West Dakota Avenue, Suite 110, Lakewood, CO, 80228

Day – Calendar day.

Pursuant to 49 U.S.C. 60112, I hereby order Respondent to immediately take the following corrective actions:

1. ***Operating Pressure Restriction.*** Hilcorp must immediately reduce operating pressure to no more than 65 psig along the entire length of the *Affected Segment*.
 - a. This pressure restriction is to remain in effect until written approval to increase the pressure or return a pipeline to its pre-failure operating pressure is obtained from the Director.
 - b. Within 15 days from the date of this Order, Respondent must provide the Director the actual operating pressures of each regulation station supplying natural gas to the *Affected Segment* at the time of failure and the reduced pressure restriction set-points at these same locations.
 - c. This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.
2. The *Affected Segment* must be temporarily repaired within 15 days from the date of this Order, and permanently repaired within 30 days from the date of this Order. If the MGS-A pipeline is not permanently repaired within 30 days from the date of this Order, Hilcorp must shut down the MGS-A pipeline consistent with Section B.2 of Hilcorp’s repair plan titled, “*Middle Ground Shoal Facilities and Pipeline Shutdown Plan*,” revision dated April 27, 2017, and keep it shut down until authorized to resume operation by the Director. If the *Affected Segment* must be shut down under the terms of this Order, the shutdown must be completed no later than 45 days from the date of this Order. Hilcorp must notify the Director, in writing, at least 5 days prior to commencing shutdown operations.
3. Hilcorp must notify the Director by telephone within one hour of a confirmed discovery of any abnormal operating conditions, as defined in Part 192, or other issues regarding the

safe operation of the *Affected Segment* at any time, 24 hours a day/7 days a week, after the issuance of this Order. In the event the Director is unavailable, Hilcorp must notify the Alaska Operations Supervisor, PHMSA, within the time requirement set forth in this paragraph.

4. Prior to making the permanent repair, Hilcorp must use its best efforts to reduce and maintain the pressure of the *Affected Segment* as low as practical to ensure that water does not intrude the residual oil-contaminated line or otherwise jeopardize safety or the environment. In no event, however, may Hilcorp increase the pressure above 65 psig without prior written approval from the Director.
5. Hilcorp must develop and implement a "Pipeline Leak Inspection and Repair Plan" for the *Affected Segment*. Hilcorp must submit the "Pipeline Leak Inspection and Repair Plan" for approval to the Director no later than 15 days from the date of this Order. Once approved by the Director, the plan is incorporated by reference into this Order. Respondent must complete the actions specified in the plan according to its timeline.
6. Hilcorp must develop and implement an "Inspection Plan" for the *Affected Segment*. Hilcorp must submit the plan to the Director for approval no later than 45 days from the issuance of the Order. At a minimum, the plan must include the high-resolution side-scan sonar inspection, or equivalent technology, and inline inspection. Once approved by the Director, the plan is incorporated by reference into this Order. Respondent must complete the actions specified in the plan according to its timeline.
7. ***Removal of Pressure Restriction.***
 - a. The Director may allow the removal or modification of the pressure restriction upon a written request from Respondent demonstrating that modifying or restoring the *Affected Segment* to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.
 - b. The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from Respondent demonstrating that temporary mitigative and preventive measures are implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the failure cause and provision of evidence that preventative and mitigative actions taken by the operator provide for the safe operation of the *Affected Segment* during the temporary removal or modification of the pressure restriction. Appeals of determinations by the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.
8. ***Root Cause Failure Analysis.*** Within 120 days following receipt of this Order, Respondent must complete a *root cause failure analysis* (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be supplemented or facilitated by an independent third-party and must document the decision-making process and all factors contributing to the failure. Respondent must obtain prior approval from the Director of Respondent's selection of the independent third-party. The final report must include

findings and any lessons learned and whether the findings and lessons learned are applicable to other locations within Respondent's pipeline system.

9. ***Replacement Plan (RP).***

- a. Within 45 days following the issuance of this Order, Respondent must submit to the Director for approval a *Replacement Work Plan (RP)* for replacement of the *Affected Segment*.
- b. Once approved by the Director, the RP is incorporated by reference into this Order.
- c. The Respondent must complete the replacement of the *Affected Segment*, as described in the approved RP, within 365 days of the date of this Order.

10. ***CAO Documentation Report (CDR).*** Respondent must create and revise, as necessary, a CAO Documentation Report (CDR). When Respondent has concluded all the items in this Order it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by Respondent with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.

- a. The Director may approve the CDR incrementally without approving the entire CDR.
- b. Once approved by the Director, the CDR will be incorporated by reference into this Order.
- c. The CDR must include, but is not necessarily limited to, the following:
 - i. Table of Contents;
 - ii. Summary of the Incident and the response activities;
 - iii. Summary of pipe data, material properties and all prior assessments of the *Affected Segment*;
 - iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;
 - v. Summary of the RCFA with all root causes as required by the Order;
 - vi. Documentation of all actions taken by Respondent to implement the RP, the results of those actions, and the inspection and repair criteria used;
 - vii. Documentation of any revisions to the RP including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;
 - i. Lessons learned while completing this Order;
 - ii. A path forward describing specific actions Respondent will take on its entire pipeline system as a result of the lessons learned from work on this Order; and
 - iii. Appendices (if required).

Other Requirements:

11. **Approvals.** With respect to each submission that under this Order requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director, and resubmit it for approval.
12. **Extensions of Time.** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.
13. **Reporting.** Respondent must submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on July 12, 2021. The Director may change the interval for the submission of these reports.
14. **Documentation of the Costs.** It is requested that Respondent maintain documentation of the costs associated with implementation of this CAO. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies, and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements, and other modifications; and (3) environmental remediation, if applicable.

Be advised that all material you submit in response to this enforcement action is subject to being 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).

In your correspondence on this matter, please refer to “CPF No. 5-2021-019-CAO” and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent’s pipeline system under 49 C.F.R. Parts 190 through 199, under any other order issued to Respondent under authority of 49 U.S.C. Chapter 601, or under any other provision of Federal or State law.

Respondent may appeal in writing any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued