NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: mhummel@northstarmidstream.com, tchadwick@northstarmidstream.com, pbautista@northstarmidstream.com

June 15, 2021

McMillan Hummel
Chief Executive Officer
NorthStar Holdco Energy, LLC
10077 Grogans Mill Rd Suite 530
The Woodlands, TX 77380

CPF 3-2021-052-NOPV

Dear Mr. Hummel:

On various dates between January 2018 and September 2018, 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 NorthStar Holdco Energy, LLC's subsidiary, NorthStar Midstream's (NST) crude oil pipeline system between East Fairview and Alexander, North Dakota.

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

1. § 195.262 Pumping equipment.

(a) . . .

(c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

NST failed to test and determine that pumping station safety devices were functioning properly prior to operation per § 195.262(c). PHMSA determined that seven safety devices for pumping stations located at East Fairview (three devices) and Alexander Station (four devices) were not functioning properly (as per described in applicable control narratives) before November 16, 2016, the date when the commodity was introduced to the pipeline.

PHMSA reviewed records dated October 3, 2018, and the associated work orders #ST120222 and #ST120221. This information detailed that fire, Hydrogen Sulfide (H2S), and Lower Explosive Limit (LEL) detectors did not sound any alarms or shutdowns. Section 2.2 of NST procedure, *Station General Protectives of the Control Narratives for*

East Fairview and Alexander Station, stated, "these devices would have resulted in a pump shut down."

NST's correspondence to PHMSA on October 16, 2018, identified that the condition had not been corrected at the local facility or at the Remote Operations Center.

2. **§ 195.406 Maximum operating pressure.**
(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:
(1) . . .
(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under subpart E of this part.

NST failed to follow maximum operating pressure guidelines per § 195.406(a)(3) by operating segments of its pipeline at a pressure that exceeded 80% of the test pressure (pressure tested under subpart E of Part 195) during normal operations. PHMSA inspectors reviewed actual discharge maximums by month for the East Fairview location and found that in calendar years 2017 and 2018, the pressure exceeded 80% of the hydrostatic test pressure for the following locations:

East Fairview Regulated Low Pressure				
Location at Northstar Express Pipeline. Stations. Fairview Pipeline. Station Analog Points.	Month/Year of Pressure Exceedance	Hydrostatic Test Pressure (psi)	80% of Test Pressure	Actual Discharge Pressure (psi)
PIT-126	Apr/2017	370	296	300.0721
PIT-126	Aug/2017	370	296	307.4821
PIT-126	Jan/2018	370	296	317.0023
PIT-126	Feb/2018	370	296	300.2194
PIT-030	Jan/2018	370	296	308.0219

NST provided no records to substantiate that these events occurred due to surges or other variations from normal operations.

3. **§ 195.406 Maximum operating pressure.**
(a) . . .
(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

NST failed to provide adequate controls and protective equipment to limit pressures during surges or other variations from normal operations. Specifically, NST failed to limit the operating pressure of the pipeline system from exceeding 110% of MOP established under § 195.406(a) at the following locations:

East Fairview Regulated Low Pressure				
Location at Northstar Express Pipeline. Stations. Fairview Pipeline. Station Analog Points.	Month/Year of Pressure Exceedance	MOP	110% MOP	Actual Discharge Pressure (psi)
PIT-030	Mar/2017	285 - ANSI 150	313.5	659.04
PIT-030	Nov/2017	285 - ANSI 150	313.5	1112.031
PIT-030	Dec/2017	285 - ANSI 150	313.5	394.6846
PIT-030	Mar/2018	285 - ANSI 150	313.5	526.7396

Regulated High Pressure				
Location at Northstar Express Pipeline. Stations. Fairview Pipeline. Station Analog Points.	Month/Year of Pressure Exceedance	MOP	110% MOP	Actual Discharge Pressure (psi)
PIT-019	Jun/2018	1480 - ANSI 600	1628	2590.989
PIT-019	Jul/2018	1480 - ANSI 600	1628	2590.989
PIT-019	Aug/2018	1480 - ANSI 600	1628	2576.025
PIT-217	Mar/2017	1480 - ANSI 600	1628	2501.186

4. **§ 195.420 Valve maintenance.**

(a) . . .

(b) Each operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

NST failed to inspect each mainline valve to determine if it is functioning properly at intervals not exceeding 7 ½ months per § 195.420(b). NST provided Form 18.10 Valve Inspection Form dated April 19, 2018, for MOV's 001 East and West Yellowstone River, which indicated that both of these river valves were operated during the inspection on that date. PHMSA determined that both of these river valves are monitored through the SCADA system and requested SCADA data for this time frame to confirm that the valves were in fact operated as indicated on the Form 18.10 to determine they are functioning properly. The data showed that the West River Valve was operated, but the data showed no indication that the East River Valve was operated on this day. PHMSA requested East

River Valve SCADA data several times and has not received any information from NST confirming this valve's operation to determine it was functioning properly.

5. **§ 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 1⁄2 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.

NST failed to inspect and test a total of 21 overpressure protection devices at intervals not exceeding 15 months, but at least once each calendar year. Specifically, the devices that were not inspected in 2017 are:

Device number	Date of Device Inspection	Device Set Date and initial inspection
4728	4/23/2018	3/7/2016
4729	4/23/2018	3/4/2016
4730	4/23/2018	3/4/2016
4731	4/23/2018	3/18/2016
4732	4/23/2018	3/18/2016
4733	4/23/2018	8/15/2016
4734	4/23/2018	3/18/2016
4735	4/23/2018	3/18/2016
4736	4/23/2018	3/17/2016
4744	4/23/2018	3/17/2016
4745	4/23/2018	3/18/2016
4746	4/23/2018	3/17/2016
4747	4/23/2018	8/15/2016
4748	4/23/2018	3/17/2016
4749	4/23/2018	8/15/2016
4762	4/19/2018	3/18/2016
4763	4/19/2018	3/18/2016
4764	4/19/2018	3/18/2016
4765	4/19/2018	3/18/2016
4766	4/19/2018	3/17/2016
4767	4/19/2018	3/18/2016

Also, NST failed to inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it functioned properly, is in good mechanical condition, is adequate from the standpoint of capacity and reliable for operation of the service for 29 devices. The table below depicts the device and the lack of sufficient documentation to determine the pressure at which 28 devices activated. In addition, one device is listed below that exceeded its pressure relieving set point when tested, but the record provided does not indicate that the device was inspected such that this was corrected during the inspection and proved to be reliable.

Device number	Release Pressure documented (Yes/No)	Record documentation	Location
4728	No	Incomplete	Alex
4729	No	Incomplete	Alex
4730	No	Incomplete	Alex
4731	No	Incomplete	EFV
4732	No	Incomplete	EFV
4733	No	Incomplete	EFV
4734	No	Incomplete	EFV
4735	No	Incomplete	EFV
4736	No	Incomplete	EFV
4737	No Exceeded pressure	Incomplete	AJ
4738	No	Incomplete	AJ
4739	Yes	Incomplete	AJ
4740	Yes	Incomplete	AJ
4741	Yes	Incomplete	AJ
4742	Yes	Incomplete	AJ
4743	Yes	Incomplete	AJ
4744	Yes	Incomplete	EFV
4745	Yes	Incomplete	EFV
4746	Yes	Incomplete	EFV
4748	Yes	Incomplete	EVF
4749	Yes	Incomplete	EFV
4758	Yes	Incomplete	Alex
4759	Yes	Incomplete	Alex
4762	No	Incomplete	EFV
4763	Yes	Incomplete	EFV
4764	Yes	Incomplete	EFV
4765	Yes	Incomplete	EFV
4766	Yes	Incomplete	EFV
4767	Yes	Incomplete	EFV

6. **§ 195.446 Control room management.**

(a) . . .

(c) *Provide adequate information*. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) . . .

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

NST failed to conduct point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays. A total of three instances were identified.

PHMSA reviewed documents provided by the operator as it relates to point-to-point verification. The pipeline became operational in November 16, 2016, but the operator has not to date provided commissioning records or other records providing verification that point-to-point was conducted for point(s) that impact safety when the system was originally validated to the SCADA system. The point-to-point record dated January 31, 2018 did not include confirmation that each point that can impact safety was verified to the relevant SCADA displays. In addition, field values and SCADA values recorded have considerable variability without sufficient reconciliation in the records or comments including missing calibration ranges (for example a reading originally recorded as a pressure reading became a temperature "Northstar Express Pipeline.Stations.Alexander Junction.Station Analog Points.TIT-109" which would not have the same calibration ranges or display ranges). SCADA and field related values were present in the records provided without explanation or corrective actions identified. For example, 11-2-17 DIT-727 SCADA Value 1 - 47.20908, and Field Value 1 - 0.7928, where these two values should be equivalent unless explained as a conversion of some type but this was not referenced in the record.

7. **§ 195.446 Control room management.**

(a) . . .

(e) Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) . . .

(3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months;

NST failed to provide records that demonstrate compliance with the requirements of § 195.446(e)(3) for verification of correct safety-related alarm set point values and alarm descriptors when associated field instruments are calibrated or changed at least once each calendar year, but at intervals not to exceed 15 months. A total of three instances were identified.

Form 11-12 only confirms that a review was performed once each calendar year, at intervals that did not exceed 15 months. However, records were not available to demonstrate the correct alarm set point values or correct alarm descriptors at the time of the review, nor were records available to demonstrate how the correct alarm set point values and alarm descriptors were confirmed, as required by § 195.446(e)(3). In addition, the operator failed to produce documentation that safety alarm set-point values and alarm descriptors were verified when field instruments were calibrated or changed.

8. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . .

(b) ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**

(1) . . .

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	**Date**
Category 1	**December 31, 2001.**
Category 2	**November 18, 2002.**
Category 3	**Date the pipeline begins operation.**

NST failed to identify each pipeline segment that could affect an HCA area prior to beginning pipeline operations.

The earliest information provided by NST that determined which pipeline segments could affect an HCA (referred by NST as indirect HCA's) was a report titled "Northstar Midstream Services Company LLC Liquid Pipeline HCA Analysis" that was dated June 29, 2018. According to NST's website, the commissioning of the pipeline was more than two years earlier on November 16, 2016. PHMSA identified during the inspection in September of 2018 that Alexander Junction pump station was in a could-affect HCA. NST's report did not include Alexander Junction pump station as being in a could-affect HCA location.

The earliest information provided by NST that determined which pipeline segments could affect an HCA (referred by NST as indirect HCA's) was a report titled "Northstar Midstream Services Company LLC Liquid Pipeline HCA Analysis" that was dated June 29, 2018. According to NST's website, the commissioning of the pipeline was more than two years earlier on November 16, 2016. PHMSA identified during the inspection in September of 2018 that Alexander Junction pump station was in a could-affect HCA. NST's report did not include Alexander Junction pump station as being in a could-affect HCA location.

9. § 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 (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:**
(1) . . .
(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys;[a]

NST failed to analyze all available information about the integrity of the entire pipeline and the consequences of a failure.

NST did not have an information analysis, also referred to as risk analysis or risk model, between November 16, 2016 and September 2018. NST completed its risk analysis on September 17, 2018. A risk model for analysis relevant to the baseline assessment did not exist.

During the inspection PHMSA determined that the risk model had not been updated with all available information, such as third-party digs near the asset, changes in land use, geotechnical hazards, corrosion data, etc

Information that could change the reassessment interval had not been integrated into the risk model at the time of inspection. Areas that need to be incorporated into the risk model that is actual datum and available to the operator including, but are not limited to, third-party digs near the asset, changes in land use, geotechnical hazards, and corrosion control data. The risk model was reviewed and did not incorporate the following identified corrosion datum:

1. A CP system was designed. Proposal/Design dated 4/4/2016;
2. Two CP systems were installed, MATCOR installed Final GB installed on 4/3/2017;
3. A Native Survey was performed before any of the CP systems were energized. Surveyed this line between 06/09/2017 to 06/11/2017;
4. The CP systems were energized shortly after the Native Survey was performed.
5. A polarized potential test point survey was performed. Annual Survey finished on 11/2/2017; and
6. Rectifier Survey finished on 5/16/2018.

PHMSA identified the pump station located at Alexander Junction or Dore Junction (due to being in Dore County) at the time of the inspection as being in a no flow operating condition. The operator confirmed verbally that this operating condition had been in place for an extended period. However, the risk analysis or risk model did not consider the elevated threat of internal corrosion due to no or low flow operating conditions.

[a] The regulation was amended after the inspection. The regulation language contained herein was in force at the time of the inspection.

10. **§ 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) . . .

(3) *Leak detection*. An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

NST failed to adequately include a means to evaluate the capability of its leak detection in its Integrity Management Program (IMP) between November 16, 2017 and September 10, 2018. The operator used the original hydrotest as the integrity program baseline assessment. A hydro test is not a monitoring system as required by the regulation. Specifically, Section 7.5 – Leak Detection Capability was modified in NST's IMP as of September 10, 2018. The Annual Evaluation Report of the IMP dated March 31, 2018 identified the need for this correction.

11. **§ 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.

NST failed to document 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 §192.452. Specifically, NST could not provide documentation indicating why NST did not perform a close interval survey (CIS), in calendar years 2017 and 2018. Cathodic protection was installed and energized on June 23, 2017. In reports to NST for 2017 and 2018, a third-party consultant recommended a CIS be performed. Yet, NST has not conducted a CIS or documented justifications or decisions for performance failure cause.

12. **§ 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.

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.**

NST failed to electrically check rectifiers for proper performance at least six times each calendar year, but with intervals not to exceed 2.5 months. The cathodic protection system was energized on June 23, 2017. As identified during the inspection of NST records, all rectifiers known to PHMSA during the inspection (three locations) were missing three inspection cycles:

Rectifier	**Report Inspection Date**	**Missing**	**Report Inspection Date**	**Missing**	**Missing**	**Report Inspection Date**
Alexander Terminal	6/23/2017	9/6/2017	10/27/2017	1/10/2018	3/26/2018	4/24/2018
Yellow Stone Block Valve	6/23/2017	9/6/2017	10/27/2017	1/10/2018	3/26/2018	4/24/2018
Fairview Rail Terminal	6/23/2017	9/6/2017	10/27/2017	1/10/2018	3/26/2018	4/24/2018

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, NorthStar Holdco Energy, LLC is subject to a civil penalty not to exceed $222,504 per violation per day the violation persists, up to a maximum of $2,225,034 for a related series of violations. For violation occurring on or after July 31, 2019 and before January 11, 2021, the maximum penalty may not exceed $218,647 per violation per day the violation persists, up to a maximum of $2,186,465 for a related series of violations. For violation occurring on or after November 27, 2018 and before July 31, 2019, the maximum penalty may not exceed $213,268 per violation per day, with a maximum penalty not to exceed $2,132,679. For violation occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022. We have reviewed the circumstances and supporting documentation involved for the above probable violation(s) and recommend that you be preliminarily assessed a civil penalty of $687,100 as follows:

Item number	PENALTY
1	$85,300
2	$70,100
3	$87,700
5	$190,500
6	$58,400
7	$54,900
8	$46,600
12	$93,600

Warning Items

With respect to Items 4, 9, 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.

Proposed Compliance Order

With respect to items 1, 2, 3, 5, 6, and 7, pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to NorthStar Holdco Energy, LLC. 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 the receipt of this Notice, you have 30 days to submit written comments, or request a hearing under 49 CFR § 190.211. 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. This period may be extended by written request for good cause.

In your correspondence on this matter, please refer to **CPF 3-2021-052-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Gregory A. Ochs
Director, Central Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

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

cc: Tara Chadwick – tchadwick@northstarmidstream.com
Pablo Bautista – pbautista@northstarmidstream.com

PROPOSED COMPLIANCE ORDER

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

1. In regard to Item Number 1 of the Notice pertaining to safety devices, the operator must test each safety device under conditions approximating actual operations to ensure they are functioning as designed. A schedule for testing of safety devices must be submitted to the Director, Central Region within 30 days of the final order. Completion of this testing shall not exceed 6 months from the issuance of the final order.

2. In regard to Item Number 2 and 3 of the Notice pertaining to pipeline being operated at a pressure that exceeded 80% of the test pressure and pipeline exceeding 110% of MOP during surges or other variations from normal operations, the operator must conduct tests, or inspection activities, to confirm that each pipe segment where pressure was exceeded, the pipe integrity has not been compromised and must provide adequate controls and protective equipment to control the pressure within affected segments. This shall include launchers and receivers and associated piping to establish MOP. A new surge analysis to match the configuration of the pipeline shall be completed as part of this action. A plan and associated schedule for completion of activities to confirm pipeline integrity and that adequate controls are performing as designed must be submitted to the Director, Central Region within 30 days of the final order. Completion of the submitted plan shall not exceed 6 months from the issuance of the final order.

3. In regard to Item Number 5 of the Notice pertaining to overpressure safety devices, the operator must inspect and test all applicable devices to determine and document that they are functioning properly, are in good mechanical condition, and are adequate from the standpoint of capacity and reliability of operation. A schedule for testing of overpressure safety devices must be submitted to the Director, Central Region within 30 days of the final order. Completion of this testing shall not exceed 6 months from the issuance of the final order.

4. In regard to Item Number 6 and 7 of the Notice pertaining to point-to-point verification between SCADA displays and related field equipment or field equipment calibration, and verification of correct safety-related alarm set point values and alarm descriptors, the operator must conduct verification to confirm that each safety related alarm set-point value identified in the field is in agreement with the SCADA system and associated display values. A schedule for completion of these actions must be submitted to the Director, Central Region within 30 days of the final order. Documentation that indicates calibration ranges, alarm set-point values, checking through SCADA displays that are position sensitive, and comments associated with reconciliation shall be submitted to the Director, Central Region. Completion of this test shall not exceed 6 months from the issuance of the final order.

5. It is requested that Northstar Midstream maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Gregory Ochs, Director, Central 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.