ConocoPhillips

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Niobrara Flowline & Facility Piping Installation, Monitoring and Integrity Plan

Recommended Document Retention: CG01 Regulatory Compliance and Internal Governance

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1. General

1.1 Scope

This document details the minimum requirements for installation, monitoring, inspection, maintenance, and repair for flow lines located within ConocoPhillips's Niobrara Field. This document is intended to cover piping containing produced fluids for both buried and surface lines.

1.2 Governance

- The requirements in this document shall apply to all new facilities and modifications to existing facilities within ConocoPhillips Niobrara.
- Any deviations from this standard shall be approved by a Technical Authority in accordance with the Lower 48 Standards as well as any applicable codes and regulations.

1.3 Industry Standards and Codes

- The latest version of the listed industry standards and codes are for reference:

Code Number	Regulations
COGCC Rule 1101	Flowline Installation and Reclamation
COGCC Rule 1102	Flowline Operation Maintenance and Repair
Code Number	**American Petroleum Institute (API)**
API 5L	Specification for Line Pipe
API 1104	Welding of Pipelines and Related Facilities
Code Number	**National Fire Protection Association (NFPA)**
NFPA 70	National Electrical Code (NEC)
NFPA 30	Flammable and Combustible Liquids Code
Code Number	**American Society of Mechanical Engineers (ASME)**
ASME B31.3	Process Piping
ASME B31.8	Gas Transmission and Distribution Piping Systems
ASME BPVC Sec. IX	Qualification Standard For Welding, Brazing, And Fusing Procedures
ASME B1.20.1	Pipe Threads, General Purpose (Inch)
ASME B16.20	Metallic Gaskets for Pipe Flanges Ring-Joint, Spiral-Wound, and Jacketed
Code Number	**National Association of Corrosion Engineers (NACE)**
MR0175/ISO 15156	Petroleum and natural gas industries — Materials for use in H2S-containing environments in oil and gas production

1.4 Definitions

Company	The term “Company” shall mean ConocoPhillips or any entity represented by ConocoPhillips.
Contractor	Company or business that agrees to furnish materials or perform specified services at a specified price and/or rate to the Owner.
Inspector	A ConocoPhillips appointed engineer or inspector.
Flowline	The portion of piping extending from the wellhead to the inlet of the separation vessel or first piece of production equipment.
Facility Piping	All piping, excluding the flowline, resident on or with the surface facility located between the wellhead and point of sales or custody transfer.
Manufacturer	The recipient of a direct or indirect purchase order for materials and/or equipment. In this context, a direct order is one issued to a manufacturer by a contractor or the Owner.
Owner’s Engineer	A ConocoPhillips appointed engineer.
all-thread nipples	Pipe nipples that are threaded along the entire length of the nipple
MAOP	The maximum pressure pressurized system may safely hold in normal operation
Sour Service	Fluids containing water and hydrogen sulphide (H_2S) that is at a total pressure of 0.4MPa (65psia) or greater, and if the partial pressure of hydrogen sulphide in the gas is greater than 0.0003MPa (0.05psia)
Sweet Service	Fluid stream containing less hydrogen sulphide (H_2S) than that of a sour service.
Jeeping	Refers to the use of a holiday detection meter to find and locate imperfections in piping coating.
Fusion-Bonded Epoxy (FBE)	An epoxy powder coating used to protect pipe from exterior corrosion.
Preventative maintenance (PM)	The maintenance performed on equipment that lessens the likelihood of equipment failure.
Multi-Skilled Operator (MSO)	Company appointed personnel trained to operate and troubleshoot production equipment.

2. Installation:

2.1 Design:

All flow lines and facility piping are designed and constructed in accordance with ASME B31.3, B31.4 or B31.8 engineering standards as applicable and have a wall thickness not less then what in required in these codes. All underground piping and fittings have welded connections unless a transition is made to non-metallic piping sub-surface. Non-metallic piping is used in accordance with manufacturer recommendations. All flow lines are reviewed and approved by a Company engineer prior to being put into service. Any lines in sour service are constructed to the requirements outlined in NACE MR0175/ISO 15156.

2.2 Fabrication:

- Welded/Flanged Components:

All welders and welding procedures used in pipe fabrication are qualified in accordance with ASME Section IX or API 1104. All welding procedures comply with ASME B31.3/B31.8 welding requirements. All welds are full penetration welds except socket welds, pipe support attachment welds, and fillet welds where specified.

All flanged connections are made by tightening the flange bolts in an accepted pattern to an even torque. All piping gaskets are manufactured in accordance to ASME B16.20.

- Threaded Components:

Any threaded connections are NPT threads and conform to ASME B1.20.1. All threaded joints use pipe dope/thread tape during fit up in order to better prevent leaks. All threaded piping components are a minimum of SCH 80 pipe wall to ensure there is enough wall thickness to support the cutting of threads and external pipe loads. The use of “all-thread” nipples or one-step bushings is prohibited in hydrocarbon services.

- Non-Metallic Piping:

Any non-metallic piping is installed under the supervision of qualified personnel trained in the specific non-metallic piping system. All non-metallic piping systems are installed as per manufacturer recommendations to help ensure piping components are not damaged by the installation process. All transitions joints from metallic piping to non-metallic or from non-metallic to non-metallic piping are manufacturer approved. All non-metallic piping is buried with tracer wire.

2.3 Inspection:

- Visual Inspection: Prior to assembly of piping components, all pipe, valves, and fittings are visually inspected for defects. Post assembly, all joints are visually inspected by an appropriately trained and experienced person.

- Weld NDT: A minimum of 10% of the welds are examined on a random basis using radiographic examination, ultrasonic testing, magnetic particle testing or other approved testing method as outlined in ASME B31.8. All sub grade/buried welds undergo 100% weld inspection through one of the approved methods as listed in ASME B31.8 at the time of construction.
- Leak Test: Prior to being put into service all piping systems undergo a hydrostatic leak test in accordance with the appropriate ASME B31 code. This hydrostatic test is performed at a pressure of no less than 1.25 times the MAOP of the piping system.

2.4 Corrosion Protection:

- Metallic Piping Corrosion allowance:

a. Sweet Service: A minimum of 1/32" is added as extra wall thickness for corrosion

b. Sour Service: A minimum of 1/16" is added as extra wall thickness for corrosion

- Coating:

c. Above Ground Piping: Above ground piping will be painted with a coating selected by the Company's engineer for the specific application that will help prevent corrosion from ambient conditions.

d. Underground Piping: All below ground piping is protected from external corrosion through the use of external coatings and/or wrappings. The standard coating system used is fusion bonded epoxy (FBE). Coatings are examined for defects or "holidays" through "jeeping" of the pipe; soil to air transitions are protected with protective tape wrapping applied over the FBE coating and the pipe is padded with soil containing no medium to large sized rocks prior to burial.

- Cathodic Protection: Sacrificial anodes and insulating gasket kits are used in conjunction with underground coating systems to protect buried metallic lines from external corrosion.

2.5 Documentation:

- Process drawings: Process drawing that show the location of isolation valves are stored within company document management systems.
- Flow line location: Currently all buried flow lines stay within the bounds of the Company production site containing the well which they service. The location access is restricted via fence and locked gate. During construction buried flowlines are mapped on a site security diagram and can also be easily located with line locating equipment. The maps are kept in paper format, but are not kept in a GIS database because of the short length and on-pad location.

3. Monitoring

3.1 Instrumentation

- Pressure Transmitter & Programmable Logic Controller: The flow line is designed to be continuously monitored by a pressure indicating transmitter (PIT) that is linked to a programmable logic controller (PLC). This system monitors for pressure of the flow line to ensure the system stays within normal operating ranges. If the flow line pressure drops too low, indicating the possibility of a leak, or if the flow line pressure gets too high, the system will send a signal to an emergency shut down valve (ESD) to shut in the well. This system incorporates several fail safes to increase reliability. These fail safes include a shut off signal being sent to the ESD valve if communication is lost to the PIT or if power is lost to the site.
- Emergency Shut Down Valve (ESD): An ESD valve is located at the start of the flow line prior to the line going underground. The ESD and upstream piping is selected by the owner's engineer to have a MAWP greater than the maximum anticipated shut in pressure of the well. All ESD valves are fail closed and can only be re-opened by onsite personnel.

3.2 Data Recording

Flow line pressure data is pulled from the onsite PLC to a SCADA (supervisory control and data acquisition) system where the data is stored for all wells. This data can be viewed real time or at a later date to establish trends.

3.3 Personnel Monitoring

If the flow line pressure deviates from normal the ESD valve will automatically shut as outlined in section 3.1. Simultaneous to this shutdown a notification will be sent to a company appointed representative who will travel to the well location as soon as practicable to investigate the pressure deviation.

Additionally, a company appointed representative shall walk down the flow line on a weekly basis to look for signs of leakage. This will include an AVO (Audio, Visual, and Olfactory) inspection of the above ground piping as well as a visual surface/ground inspection of the buried flow line segments.

4. Inspection

4.1 Risk Based Inspection Program:

All Company facilities are inspected using a risk-based inspection program. This methodology takes into account the risk of the component in question (determined by the probability and consequence of failure) in order to develop an appropriate inspection interval based on the predicted time to failure and consequence of failure.

All inspected items are cataloged via a corrosion and inspection tracking database and maintained for the life of the component. Data entered into this system is used to establish recurring inspection intervals.

All known damage is monitored as appropriate, or, depending on the severity, is repaired or replaced.

4.2 Operator Lease Inspection

Wellsite operators are required to visit all Company operated wells a minimum of once per week to visually inspect the site for any integrity or operational issues. In addition to these weekly visits, operators are also required to conduct a comprehensive lease inspection annually.

4.3 SPCC Inspections:

The Company has developed a Spill Prevention Control and Countermeasures plan for all wellsite locations in accordance with the US Environmental Protection Agency Clean Water Act Section 311(j)(1)(C) (i.e. 40 CFR112). These site specific plans must be reviewed and signed off by a registered professional engineer who has visited and inspected the site in question for adherence to the submitted plan. Additionally, any items pertaining to the SPCC plan must be inspected at regular intervals to ensure that locations, drainages, oil traps, sumps and skimmers are free from oil and/or produced water accumulation. Any accumulation identified must be reported and promptly cleaned up. Any equipment defects noted during these inspections shall be reported to Company supervision and addressed per the guidance in Sections 5 & 6 of this document.

5. Maintenance

5.1 Chemical Treatment

Flowline and facility chemical treatment is addressed in detail in the Niobrara chemical management plan; however, treatment is predicated on the following factors:

- Corrosion Monitoring (i.e. metal counts, corrosion coupons, failure rates, etc.)
- Bacterial Counts (increased bacterial counts dictate bio-remediation treatment)
- Presence of corrosive or non-spec constituents (i.e. H_2S, CO_2, etc.)
- Occurrence of flow assurance threats (scale, paraffin, hydrates, etc.)

5.2 Critical Equipment

1. Critical Equipment is identified as those items that are critical to Safety, Business, and/or Regulatory as defined below:
    a. Physical asset where failure or malfunction could result in an unacceptable consequence with regards to safety, the environment, asset damage, business interruption or reputation.
    b. Designation as critical equipment is based upon business or governing body standard/regulation requirements, business need, or operational risk.
2. Items identified as critical equipment are assigned a preventative maintenance (PM) order that reoccurs on an established frequency.
3. See Appendix B for a list of critical equipment items that correspond to flowline monitoring and maintenance.

5.3 Unscheduled/Emergency Maintenance

1. Should an item fail or malfunction unexpectedly leading to loss of containment or safety concerns the well or site in question will be isolated and not returned to service until properly repaired or replaced as outlined in Section 6 of this document.

6. Repair/Replacement

6.1 General

All failures resulting in a leak or loss of containment constitute a condition requiring shut down of the well facility so that the leaking section can be safely isolated, depressurized and de-inventoried, and repaired or replaced.

6.2 Reporting & Control

Malfunctions or failures of the systems responsible for the integrity management and/or monitoring of flowline systems shall be reported to Company supervision immediately upon discovery. Should the malfunction or failure of these systems pose a safety, business, or environmental risk the wellsite facility shall be shut down such that the system(s) in question can be isolated and troubleshot or replaced accordingly.

6.3 Timing

Repair or replacement of these systems is to begin as soon as practical after discovery. It is recognized that many factors (such as material or component availability, cost, labor availability, etc.) will affect the time required to return the well to service. These factors should be minimized to the best of the Company's ability to ensure a timely return to service.

NOTE: A well needing repair or replacement of any of the components discussed in this document will not be returned to operation until such time those items are repaired or replaced to ensure mitigation of any safety, environmental, or business related threats.

7. On-Line Integrity Testing

7.1 Buried Flowlines

The section of piping beginning at the wellhead and terminating at the separation vessel or first piece of intervening process equipment shall be tested to the maximum anticipated operating pressure at a frequency established under regulation set forth by the Colorado Oil and Gas Conservation Commission (COGCC) or as agreed upon by Company and COGCC via a COGCC Rule 502.b variance request.

7.2 Facility piping

All segments of piping extending from the wellhead to the point of custody transfer or sales which exclude the flowline as defined above, will not be pressure tested to the maximum anticipated operational pressure conditional upon COGCC approval of a variance from Rules 1101 & 1102. This piping will instead continue to be monitored through such means as AVO inspections, FLIR Camera inspection, comprehensive

annual lease inspections, and other programs as necessitated or required throughout the life of the surface facility.

7.3 Other Piping

Any piping which does not conform to the descriptions given in sections 7.1 & 7.2 (e.g. flow back piping, gas lift gas injection piping, etc.) shall be considered nonstandard from the guidance and governance of this document. Such piping shall conform to industry standard and the requirements of the applicable governing regulatory authority.

APPENDIX A – Current Flowline Inventory

Wells Name	Location	Flowline Stays On COP Location?	Approximate Buried Flowline Length
BOMHOFF 5 8H	39°43'8.818"N, 104°33'49.226"W	Yes	150’
CLINE 4-64 2-1H	39°42'58.09"N, 104°30'33.14"W	Yes	150’
CONVERSE FAMILY 6-1H	39°43'43.979"N, 104°28'17.72"W	Yes	150’
COTTONWOOD CREEK 4-65 26-27 1H	39°40'37.78"N, 104°39'30.29"W	Yes	150’
GRIMM 34-4H	39°39'10.53"N, 104°32'34.08"W	Yes	150’
GRIMM MOTOCROSS 4-65 23-24 1H	39°41'40.628"N, 104°38'29.774"W	Yes	160’
KROUT 14-1H	39°42'30.809"N, 104°30'30.611"W	Yes	150’
MURPHY FAMILY 4-64 25-1H	39°40'43.06"N, 104°30'30.8"W	Yes	150’
MURPHY FAMILY 4-64 36-1H	39°39'19.76"N, 104°29'30.65"W	Yes	150’
PROPERTY RESERVE 4-65 3-4 1H	39°43'36.458"N, 104°38'36.859"W	Yes	150’
PROSPER FARMS 4-65 11-12 1H	39°43'25.748"N, 104°38'20.353"W	Yes	150’
PROSPER FARMS 4-65 13-14 1H	39°42'18.73"N, 104°38'22.76"W	Yes	150’
RESERVE 3-65 26-1H	39°46'1.82"N, 104°38'20.93"W	Yes	150’
RESERVE 3-65 34-35 1H	39°45'8.971"N, 104°37'23.581"W	Yes	150’
SKY RANCH 4-65 9-10 1H	39°42'46.667"N, 104°38'33.752"W	Yes	150’
STATE BLANCA 1H	39°38'10.37"N, 104°36'45.569"W	Yes	160’
STATE ELBERT 1-H	39°38'56.67"N, 104°37'25.65"W	Yes	160’
STATE HARVARD 1H	39°38'10"N, 104°36'46.08"W	Yes	160’
STATE MASSIVE 1-H	39°38'56.641"N, 104°37'26.17"W	Yes	160’
STATE OF COLORADO 36-1H	39°44'40.89"N, 104°29'54.42"W	Yes	150’
STATE OF COLORADO 5-24HZ	39°36'28.8"N, 104°36'19.44"W	Yes	150’
SUNSET 4-65 21-22 1H	39°41'5.028"N, 104°38'29.774"W	Yes	160’
TEBO 1-1H		Yes	150’

	39°38'57.289"N, 104°29'29.281"W		
TEBO 29-1H	39°40'2.85"N, 104°34'6.11"W	Yes	150’
TEBO 29-2H	39°40'32.43"N, 104°33'52.45"W	Yes	150’
TEBO 3-1H	39°39'0.07"N, 104°31'47.98"W	Yes	150’
TEBO 32 3H	39°39'11.91"N, 104°34'39.48"W	Yes	150’
TEBO 33-1H	39°39'16.841"N, 104°33'51.451"W	Yes	150’
TEBO 4-1H	39°38'24.922"N, 104°33'55.62"W	Yes	150’
WALKER 12-1H	39°42'38.948"N, 104°29'24.871"W	Yes	150’
WATKINS 30-5 4H	39°40'32.49"N, 104°36'8.1"W	Yes	335’
WATKINS 30-5 5GH	39°40'31.7"N, 104°36'8.11"W	Yes	375’
WATKINS 30-5 5H	39°40'32.09"N, 104°36'8.11"W	Yes	340’
WATKINS 30-5 8H	39°40'31.732"N, 104°36'8.11"W	Yes	300’
WATKINS 4-64 19-1H	39°41'43.062"N, 104°35'5.15"W	Yes	150’
YOUNGBERG 4-64 11-1H	39°42'46.991"N, 104°30'32.321"W	Yes	150’
ZUKOWSKI 17-1H	39°42'28.289"N, 104°33'54.472"W	Yes	150’

Appendix B – Flowline Critical Equipment

Tag #	Equipment	Description	PM Frequency
PIT	Pressure Transmitter	Flowline Pressure Transmitter, Explosion-Proof Class 1 Div 1 for Group D	Annual
ESD	ESD Valve w/ Actuator	Fail Close, receives primary signal from above PIT, secondary closure triggered by loss of communication from above PIT or loss of power	Annual