

**BELLE FOURCHE PIPELINE COMPANY**  
Casper, WY 82602

**Law Department**

John J. Blomstrom, General Counsel  
Manuel A. Lojo, Attorney  
W. Jackson Stewart, Attorney

**Reply to writer:**

P.O. Drawer 2360  
Casper, WY 82602  
Phone: 307/ 266-0319  
Facsimile: 307/266-0357  
eMail: [mlojo@truecos.com](mailto:mlojo@truecos.com)

February 15, 2007

**RECEIVED**

FEB 16 2007

Chris Hoidal  
Director, Western Region  
Pipeline and Hazardous Materials Safety Administration  
12300 W. Dakota Avenue, Suite 110  
Lakewood, CO 80228

Re: CPF No. 5-2004-5010  
Petition of Reconsideration –  
Portions of Final Order

SENT TO COMPLIANCE REGISTRY  
Hardcopy  Electronically   
# of Copies 3 / Date 2/21/07

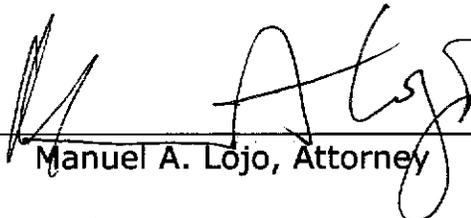
Mr. Hoidal:

Enclosed herewith is the captioned Petition for Reconsideration with respect to sub-number 3 of Item 1 and Item 10 in the Final Order in the referenced docket.

The balance of the items in the Compliance Order and Amendment of Procedures are addressed in separate responses also served at this time.

Very truly,

Belle Fourche Pipeline Company

By   
Manuel A. Lojo, Attorney

**DEPARTMENT OF TRANSPORTATION  
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION  
OFFICE OF PIPELINE SAFETY  
WASHINGTON, DC 20590**

**In the Matter of** )  
 )  
**Belle Fourche Pipeline Company** )  
 )  
**Petitioner** )  
 )

**CPF No. 5-2004-5010**

**PETITION FOR RECONSIDERATION**

Petitioner Belle Fourche Pipeline Company (BFPL) respectfully submits this Petition for Reconsideration regarding a portion of Item 3 and Item 10 of the Final Order in the above-styled matter. As grounds therefor, BFPL states as follows:

**1. FACTUAL BACKGROUND**

BFPL owns and operates crude oil pipelines in Wyoming, North Dakota and Montana. A representative of the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) Office of Pipeline Safety conducted an on-site pipeline safety inspection of Respondent's hazardous liquid pipeline facilities in Montana and Wyoming and supporting Operation and Maintenance records in Casper, Wyoming. As a result of the inspection, on May 19, 2004, the Director of the Western Region, PHMSA issued respondent a Notice of Probable Violation, together with a Proposed Civil Penalty, Proposed Compliance Order and

PETITION FOR RECONSIDERATION  
BELLE FOURCHE PIPELINE COMPANY

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Notice of Amendment (Notice) in which were set forth a number of items finding specified shortcomings, proposing a civil penalty and requiring a number of corrective actions.

BFPL filed a timely response June 24, 2004, in which it contested several of the allegations, explained others and requested that the proposed civil penalty be reduced. In his Final Order of December 11, 2006 (hereinafter "FO" copy attached hereto for ease of reference as Exhibit 1), received December 18, 2006, Theodore L. Willke, Acting Associate Administrator for Pipeline Safety, withdrew one allegation, reduced the civil penalty on another, assessed a total civil penalty of \$61,500, issued a Compliance Order requiring specified curative actions and required amendment of listed BFPL procedures.

BFPL previously paid the civil penalty and by separate filings, BFPL is concurrently notifying the PHMSA of its acts (a) complying with Items 1 (which includes sub-numbers 1 and 2 of Item 3), 11, 13, 14 and 16, and (b) amending its procedures. Relevant documents are furnished with respect to both (a) and (b).

However, that leaves sub-number 3 of Item 3 and Item 10 and it is these items to which BFPL is filing this Petition for Reconsideration.

**2. ITEMS 3 and 10 RELATING TO REDUCTION OF LINE PRESSURE**

Concerning these alleged violations (sub-number 3. under Item 3 and Item 10), the issue is basically the same: i.e., office records show that the segments were constructed of X52 and X60 grade pipe but Belle Fourche (a) as to Item 3 (sub-3) "did not have **sufficient construction documentation** to verify that all of the 12-inch line was of the same quality as the pipe samples tested (p.3 of FO, emphasis added)..." and (b) as to Item 10 " of using a SMYS of 60,000 psi for calculating the MOP on one pipeline section and using SMYS of

42,000 psi for the other pipeline section without having **sufficient records** or material testing or to **verify the SMYS of the pipe used in construction of either pipeline** (p.4 of FO, emphasis added).”

Clearly, the essence of the alleged violations for all three of these segments is the absence of what PHMSA characterizes as “sufficient construction documentation” or “sufficient records”, yet Belle Fourche would underscore the fact that it, indeed, has a “sufficiency” of the records.

Referring to the affidavit of Lyle Sessions ( attached as Exhibit 2), Superintendent of Operations of Belle Fourche for some 25 years, it is clear that the basic historical construction record was the map maintained in the main office of the company which showed the location of the lines and their pipe diameters, wall thicknesses and tensile strengths. The maps supplied to PHMSA are portions of that office map, as Mr. Sessions attests (paragraph 2 of, and Attachments 1, 2 and 3 to, Sessions Affidavit). This is unquestionably a “record kept in the ordinary course of business” and therefore admissible without the testimony of the person making the entry. Furthermore, the office map is still maintained, although now supplemented with other documentation as required by current regulation.

Accordingly, Belle Fourche does have competent, admissible evidence of the grade of metal used in the manufacture of these pipe segments, but PHMSA has nothing to refute Belle Fourche’s evidence.

Moreover, this map must be given more than ordinary weight since the information on it has never, in Mr. Sessions 40 years experience with Belle Fourche (25 years of which were with oversight of all Belle Fourche operations), been shown to have incorrect

information entered on it. And this statement holds true for all pipeline segments, not just those involved in this matter. (Sessions Affidavit, paragraph 4.)

If further evidence of the reliability of the office map were required, there is Mr. Sessions' personal experience with digging up some of the X52 line (Attachment 1) and seeing mill markings on it verifying that the pipe is X52 strength, exactly as shown on the map. Moreover, another verification lies in the May 2000 metallurgical seam evaluation of the pipe sample taken of the 12-inch X52 pipeline which also showed the pipe information entered on the office map to be accurate.

Thus, two independent sources confirm that the information on the office map, relevant portions of which were furnished PHMSA, is accurate.

In contrast to this double verification of the information on the office map as well as its existence as a "record kept in the ordinary course of business", PHMSA would offer only the conclusory findings that there was a "lack of sufficient construction information" and there were not "sufficient records."

Belle Fourche would certainly agree that, under today's requirements as well as those of the more immediate past, the office map with its pipe information would not suffice. However, we are dealing with pipeline construction some 40 years ago, and what were accepted record-keeping practices at that time.

After regulations began to be imposed, Belle Fourche has complied with the evolving regulations. Its compliance with the "80% rule" is one aspect of that compliance. The Final Order, holds that the "design pressure" cannot be at the level Belle Fourche specifies merely

because of PHMSA's repeated, but still unsupported, claim that there is a lack of "adequate construction records" (p. 4 FO).

3. **CONCLUSION**

In view of the foregoing, Belle Fourche submits that PHMSA could only find Belle Fourche's records "insufficient" if it either is (a) applying current record-keeping requirements to construction which occurred 40 years ago, a clearly improper standard, or (b) refusing to give credence to uncontroverted evidence which is competent, relevant and material and unquestionably admissible in a court of law.

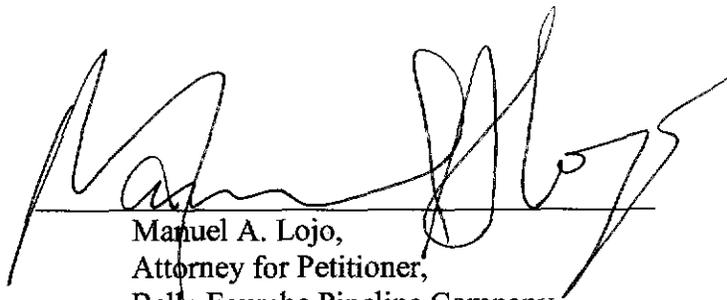
Moreover, PHMSA proposes an operational requirement which would be draconian in its effects not only on Belle Fourche but especially on all the producers it serves. Belle Fourche currently transports approximately 17,00 barrels per day (bpd) of Wyoming-produced crude oil, but at the pressures which PHMSA would require, that throughput would be reduced to 4,000-5,000 bpd, causing hundreds of wells to be shut-in. Yet PHMSA would require this in the face of abundant evidence that current pressures are safe and within regulatory requirements and without a shred of countervailing evidence.

Belle Fourche does not offer this to avoid the rightful application of the regulations, but in order that PHMSA may know that it should not take the position it does in the Final Order without strong supporting evidence, of which it has none.

Accordingly, Belle Fourche requests that the "FINDINGS OF VIOLATIONS" with respect to Sub-number 3 of Item 3 and Item 10 therein be withdrawn.

Dated this 15<sup>th</sup> day of February, 2007

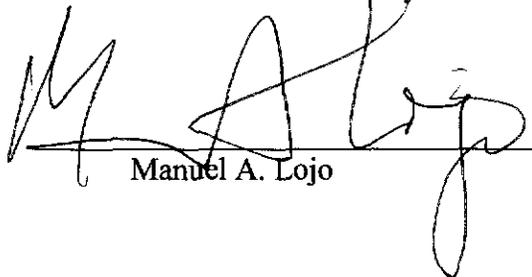
Respectfully submitted,



Manuel A. Lojo,  
Attorney for Petitioner,  
Belle Fourche Pipeline Company  
P O Drawer 2360  
Casper, WY 82602  
307.266.0319 (Direct)  
307.266.0357 (Facsimile)

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on this 15<sup>th</sup> day of February, 2007, a true and correct copy of the foregoing PETITION FOR RECONSIDERATION was served upon Chris Hoidal, Director, Western Region Pipeline and Hazardous Materials Safety Administration, via prepaid overnight service.



Manuel A. Lojo

DEPARTMENT OF TRANSPORTATION  
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION  
OFFICE OF PIPELINE SAFETY  
WASHINGTON, DC 20590

In the Matter of )  
 )  
Belle Fourche Pipeline Company, )  
 )  
Respondent )  
 )

CPF No. 5-2004-5010

FINAL ORDER

Between August 18 and 22, 2003, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration's (PHMSA's)<sup>1</sup> Office of Pipeline Safety conducted an on-site pipeline safety inspection of Respondent's hazardous liquid pipeline facilities in Montana and Wyoming and supporting Operation and Maintenance records in Casper, Wyoming. As a result of the inspection, the Director, Western Region, PHMSA, issued to Respondent, by letter dated May 19, 2004, a Notice of Probable Violation, Proposed Civil Penalty, Proposed Compliance Order, and Notice of Amendment (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent committed violations of 49 C.F.R. Part 195, proposed assessing a civil penalty of \$67,500 for the alleged violations, and proposed ordering Respondent to take certain measures to correct the alleged violations. The Notice also proposed, in accordance with 49 C.F.R. § 190.237, that Respondent amend its procedures/plans.

Respondent responded to the Notice in a letter dated June 24, 2004, later supplemented in a letter dated November 2, 2004 per PHMSA's request for additional information (Response). Subsequently, PHMSA issued an Amendment to the Notice on April 5, 2005. Respondent responded to the amended Notice in a letter dated May 3, 2005 (May 3, 2005 correspondence included in "Response"). Respondent contested many of the allegations, offered information to explain the allegations, and requested that the proposed civil penalty be reduced. Respondent did not request a hearing, and therefore has waived its right to one.

<sup>1</sup> Effective February 20, 2005, the Pipeline and Hazardous Materials Safety Administration (PHMSA) succeeded Research and Special Programs Administration as the agency responsible for regulating safety in pipeline transportation and hazardous materials transportation. See, section 108 of the Norman Y. Mineta Research and Special Programs Improvement Act (Public Law 108-426, 118 Stat. 2423-2429 (November 30, 2004)). See also, 70 Fed. Reg. 8299 (February 18, 2005) re delegating the pipeline safety authorities and functions to the PHMSA Administrator.

**FINDINGS OF VIOLATION**

**Item 1** in the Notice alleged Respondent violated 49 C.F.R. § 195.1(a), (b)(1-4) and § 195.402(a) in that Respondent did not include the 8-inch line segment that connects its 10-inch diameter pipeline at the Elk Creek pump station to its 12-inch diameter pipeline at the Donkey Creek pump station in its operations, maintenance, and emergency procedures manual as required by 49 C.F.R. §195.402(a).

In its June 24, 2004 letter, Respondent indicated that the 8- and 10-inch pipelines at issue had been purged and abandoned. PHMSA then requested that Respondent provide a map showing the location of those abandoned pipelines. In its November 2, 2004 letter, Respondent provided a map that depicts only a portion of the pipeline at issue as having been abandoned. The balance that has not been abandoned is depicted on its map as being 8- and 10-inch gathering only. Since a portion of this line is depicted as being 10-inch, it cannot be a gathering line as per the definition in 49 C.F.R. §195.2 that states "Gathering line means a pipeline 219.1 mm (8 5/8 in) or less nominal outside diameter that transports petroleum from a production facility." With the changes to this pipeline system, the Compliance Order below is amended to address Respondent's operational changes.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.1 (a), (b)(1-4) and § 195.402(a) in the Notice.

**Item 2** of the Notice proposed a civil penalty of \$25,500 for violation of 49 C.F.R. §§ 195.50(b) and 195.54(a) in that Respondent failed to report a 120-barrel spill that occurred at its Alzada pump station pig launching facilities on June 10, 2003 within the required 30-day period. This accident was not reported for 86 days, which was 56 days beyond the 30 days allowed by Federal regulation.

In its June 24, 2004 letter, Respondent stated that it did not contest the violation but that it requested the penalty be substantially reduced. In support of the reduction, Respondent stated that the spill was wholly contained within a containment dike and has been used as an opportunity to underscore to employees the importance of timely reporting of all spills. Here, the Respondent did not report the spill until a PHMSA inspector observed the spill, which was 86 days after the spill and 56 days after the latest that it should have been reported.

Accordingly, I find that Respondent violated 49 C.F.R. §§ 195.50(b) and 195.54(a) in the Notice.

**Item 3** in the Notice alleged Respondent violated 49 C.F.R. § 195.303 in that Respondent incorrectly applied the Risk-based alternative to pressure testing for the following pipelines:

1. 8-inch segment between Alzada and Belle Creek built in 1966;
2. 10-inch line from Belle Creek to Highway 14-16 built in 1966; and
3. 12-inch line from Donkey Creek to Guernsey built in 1968.

Respondent did a metallurgical seam evaluation on samples of the 12-inch line in May of 2000, but it did not have sufficient construction documentation to verify that all of the 12-inch line was of the same quality as the pipe samples tested. For the 8-inch segment between Alzada and Belle Creek and the 10-inch line from Belle Creek to Highway 14-16, Respondent did not complete a metallurgical seam evaluation nor did it hydro test these pipeline segments.

In its June 24, 2004 letter, Respondent stated that the Elk Creek line was removed from service on March 1 and that the Donkey Creek Line has been operating recently at a MOP of less than 1152.

Although some of Respondent's pipe has been taken out of service, substantial sections of pipeline manufactured from pre-70 electric resistance weld pipe still have not been hydrostatically tested. Respondent's metallurgical analysis of these sections of pipeline is not statistically sufficient nor does Respondent have sufficient construction records to substantiate that the entire pipeline installed is similar to the pipe that received a metallurgical analysis.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.303 in the Notice.

**Item 10** in the Notice Amendment alleged Respondent violated 49 C.F.R. § 195.406 in that Respondent has not been able to provide adequate records certifying the yield strength (SMYS) of 60,000 psi for the pipe used in construction of its 12.75-inch, .219 inch wall thickness pipeline section between Twentymile Station and Guernsey. Respondent has determined the MOP of this line section, using 49 C.F.R. §195.106 with a SMYS of 60,000 psi, to be 1440 psig. Without adequate records or materials testing that certifies the actual material strength of the pipe, Respondent cannot use a SMYS any greater than 24,000 psi, which results in a MOP no greater than 593.6 psig. Additionally, Respondent's records show that the pressure shutdown switch at the Twentymile station is set at 1440 psig, which is 243% of the design pressure lacking any pipeline material certification. Respondent normally operates this segment between 900 psig and 1100 psig.

Respondent could not provide adequate records certifying the SMYS of 42,000 psi for the pipe used in construction of its 12.75-inch, .25 inch wall thickness pipeline section between Highway 450 Station and the 12-inch mainline Junction. Respondent has determined the MOP of this line section, using 49 C.F.R. §195.106 with a SMYS of 42,000 psi, to be 1390 psig. Without adequate records or materials testing that certifies the actual material strength of the pipe, Respondent cannot use a SMYS any greater than 24,000 psi, which results in a MOP no greater than 677.6 psig. Additionally, Respondent's records show that the pressure shutdown switch at the South Hilight station is set at 1300 psig, which is 192 % of the design pressure lacking any pipeline material certification. Respondent normally operates this segment between 300 psig to 800 psig.

In its November 2, 2004 letter to PHMSA, Respondent provided a township/section map depicting the pipeline rights-of-way as a solid line with an arrow labeled "333,055' 12 3/4 .219X60 29.31#" pointing to that solid line. Respondent contends that this is a copy of an original construction map and it shows that the pipeline section in dispute is made from X-60

pipe and not X-52 pipe. Subsequently, it contends that this pipeline was correctly listed as having a MOP of 1440 psig.

Since Respondent could not provide further evidence substantiating the material strength of the pipe used in the construction of either pipeline section originally cited, PHMSA issued an Amendment to the May 19, 2004 Notice, dated April 5, 2005. That Amendment changed the violation from incorrectly calculating the MOP for the two pipeline sections to a violation of using a SMYS of 60,000 psi for calculating the MOP on one pipeline section and using a SMYS of 42,000 psi for the other pipeline section without having sufficient records or materials testing or to verify the SMYS of the pipe used in construction of either pipeline.

Respondent responded to the Amended Notice in a letter dated May 3, 2005. In that response, Respondent contends that it is permitted to operate at 80 percent of the highest operating pressure to which the pipeline was subjected to for four or more continuous hours that can be demonstrated by recording charts of logs made at the time the operations were conducted. It maintains that the Twentymile to Guernsey pipeline has been operated at 1440 psig for four or more continuous hours and it will be retrieving those documents to support this argument. Respondent asserts this would allow them to establish a MOP of 1152 which is 80% of 1440 psig. Additionally, Respondent contends that it has pressure tested its Highway 450 section to a pressure of 1500 psig in 1994 and again in 2005.

49 C.F.R. § 195.106, using Hooke's law, governs how pressure is to be determined under the code. Respondent may use 80 percent of the highest operating pressure recorded for four or more continuous hours in lieu of a pressure test. However, an operator may not operate a pipeline at a pressure that exceeds either 80 percent of the highest operating pressure or the test pressure recorded for four or more continuous hours, the design pressure of the pipe, or the pressure rating of any component. Though it may have adequate records to allow them to use 80% of an operating pressure in lieu of pressure test, it may not exceed the design pressure of the pipeline. Without adequate construction records or statistically viable metallurgical testing, it cannot use a SMYS any higher than 24,000 psi.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.406 in the Notice.

**Item 11** in the Notice alleged Respondent violated 49 C.F.R. § 195.408(a) and (b)(1) in that Respondent does not attend or monitor its Highway 14-16 pump station, which receives crude oil from tankage.

In its June 24, 2004 Response, Respondent stated that the Highway 14-16 Station is a gathering line and it has been since March 1, 2004.

It appears that the Highway 14-16 Station injects crude oil into what Respondent labeled on a map transmitted to PHMSA as "8 inch and 10 inch segments in gathering service only as of March 2004." Since the line that the Highway 14-16 Station injects crude into has pipe that is 10-inch, this pipeline appears to be transmission and not gathering as per the definition in 49 C.F.R. § 195. Therefore, because the Highway 14-16 Station appears to control the delivery

of crude oil into jurisdictional pipeline, this station must meet the requirements of 49 C.F.R. § 195.408.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.408(a) and (b)(1) in the Notice.

**Item 13** in the Notice alleged Respondent violated 49 C.F.R. § 195.428(a) in that Respondent's pressure shutdown switches only receive a functional test which does not ensure that these switches will operate at the correct pressure. Pressure transducers do not receive annual calibration to insure it is transmitting correct pressures.

Respondent responded to this issue in its June 24, 2004 letter by stating that new procedures would be written and implemented. It provided no documentation showing that all of its pressure control equipment had been properly tested and inspected, including calibration if necessary.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.428(a) in the Notice.

**Item 14** in the Notice alleged Respondent violated 49 C.F.R. § 195.432(b) in that Respondent is required by API 653 Section 4.3.1.2 to conduct a routine in-service inspection once each month. Respondent only does a routine inspection of its Sussex breakout tank once each year. During the inspection, Respondent's engineer informed the PHMSA inspector that it did not do monthly inspections.

In its June 24, 2004 correspondence, Respondent submitted its Sussex Station reports in response to this allegation. Respondent directs our attention to the far right column labeled "Signature" in these reports where there are employee initials and a handwritten "VI." Respondent contends that the "VI" stands for "Visual Inspection" and asserts that this indicates compliance with the requirements of section 4 of API Standard 653, claiming that the inspections took place on a basis more frequently than once per month. Although Respondent may rely on the handwritten "VI" markings as evidence that the tank had been visually inspected on a basis more frequently than once a month, there was not a specific column in Respondent's Sussex Station reports to indicate that the tank had been inspected.

The evidence does not support an argument that the tank was inspected in accordance with API 653 Section 4. Respondent must still include a monthly inspection that will incorporate and document the condition of those items listed under of API 653 Section 4.3.1.3 for the Sussex breakout tank.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.432(b) in the Notice.

**Item 16** in the Notice alleged Respondent violated 49 C.F.R. § 195.436 in that there is no security fencing at the Elk Creek pump station and the Alzada pump station and pig launcher facilities. The controls and facilities at these pump stations are unmanned and readily accessible by the public via state highways that are adjacent to these two stations.

The June 24, 2004 response to this issue was that both Alzada station and Elk Creek station had been abandoned. In its November 2, 2004 Response, Respondent provided evidence to support that the pipeline from Alzada to Elk Creek had been abandoned.

It appears that because the Alzada station is associated with the upstream end of this pipeline section it should be considered abandoned. However, the Elk Creek station may still be injecting crude oil into Respondent's "8-inch and 10-inch segments in gathering service only as March 2004." Since part of this line is 10-inch at least, that portion that is 10-inch is considered to be transmission. It appears that the Elk Creek station injects into this pipeline system and therefore it is considered to be a jurisdictional facility. Therefore, the Elk Creek station should have increased security provided.

Accordingly, I find that Respondent violated 49 C.F.R. § 195.436 in the Notice.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

### **WITHDRAWAL OF ALLEGATION**

**Item 17** in the Notice alleged that Respondent had violated 49 C.F.R. § 195.567 by failing to install an adequate number of test stations or demonstrate that test stations are at sufficient intervals to indicate the adequacy of the cathodic protection system. In its Response, Respondent provided a cathodic protection monitoring procedure that requires test leads to be spaced from between one to two miles. The exception to this is only allowed if one of the following has been met: 1) close interval survey has been performed, 2) operating history demonstrates no leaks nor evidence of external corrosion, or 3) pipeline inspection logs, assume for ILI, demonstrate no wall loss. If one of these exceptions is met, then Respondent's procedures assume that sufficient cathodic protection exists. In its Response, Respondent's submission of this procedure appears to have met the intent of 49 C.F.R. § 195.567. Based on this information demonstrating compliance with the regulation, I am withdrawing this allegation of violation.

### **ASSESSMENT OF PENALTY**

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed \$100,000 per violation for each day of the violation up to a maximum of \$1,000,000 for any related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require. The Notice proposed a total civil penalty of \$67,500 for the violations.

**Item 2** of the Notice proposed a civil penalty of \$25,500 for violation of 49 C.F.R. §§ 195.50(b) and 195.54(a) in that Respondent failed to report a 120-barrel spill that occurred at its Alzada

pump station pig launching facilities on June 10, 2003 within the required 30-day period. This accident was not reported for 86 days, which was 56 days beyond the 30 days allowed by Federal regulation. In its June 24, 2004 letter, Respondent stated that it did not contest the violation but that it requested the penalty be substantially reduced. In support of the reduction, Respondent stated that the spill was wholly contained within a containment dike and has been used as an opportunity to underscore to employees the importance of timely reporting of all spills. Here, the Respondent did not report the spill until a PHMSA inspector observed the spill, which was 86 days after the spill and 56 days after the latest that it should have been reported. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of \$25,500 for the violation.

**Item 10** of the Notice proposed a civil penalty of \$20,000 for violation of 49 C.F.R. §195.406, as fully described in the Amendment to the Notice and as discussed above, in that Respondent used a SMYS of 60,000 psi for calculating the MOP on the pipeline section between Twentymile Station and Guernsey and used a SMYS of 42,000 psi for the pipeline section between Highway 450 Station and the 12-inch mainline Junction without having sufficient records or materials testing to verify the SMYS of the pipe used in construction of either pipeline. As discussed above, although Respondent replied to the May 3, 2005 Amendment, it did not provide adequate construction records or statistically viable metallurgical testing that supports a SMYS higher than 24,000 psi. The segment of the pipeline that crosses the North Platte River could have an environmental or public impact. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of \$20,000 for the violation.

**Item 12** of the Notice proposed a civil penalty of \$10,000 for violation of 49 C.F.R. §195.410 in that Respondent failed to maintain an adequate number of pipeline markers to accurately determine the pipeline location. Furthermore, when the PHMSA representative called the emergency phone number shown on the pipeline markers for the Montana/Dakota pipeline, he received a disconnected phone message with no forwarding phone number. In its June 24, 2004 Response, Respondent notes a typographical error in the Notice. Since the body of the Notice addresses Respondent's alleged violation and the paragraph on civil penalties lists Notice Item 12 as a proposed civil penalty, the typographical mistake is a harmless error. Respondent requested that no penalty be assessed since it intends to continue installing additional correct markers. However, Respondent has not presented any information that would warrant a reduction or withdrawal of the civil penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of \$10,000 for the violation.

**Item 14** of the Notice proposed a civil penalty of \$12,000 for violation of 49 C.F.R. §195.432(b) in that Respondent is required by API 653 Section 4.3.1.2 to conduct a routine in-service inspection once each month. Respondent only does a routine inspection of its Sussex breakout tank once each year. As discussed above, Respondent's Response does not support that the Sussex tank was inspected in accordance with API 653 Section 4; however, it appears that the tank was minimally looked at periodically, which supports a reduced penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a reduced civil penalty of \$6,000 for the violation.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of \$61,500. Respondent has the ability to pay this penalty without adversely affecting its ability to continue in business.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-300), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-8893.

Failure to pay the \$61,500 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

### COMPLIANCE ORDER

The Notice proposed a Compliance Order with respect to Items 1, 3, 10, 11, 13, 14, and 16 in the Notice (Notice Item 17 was withdrawn). Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under Chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations. Respondent must-

1. With respect to Item 1 of the Notice, incorporate into its operations, maintenance, and emergency manual as required by 49 C.F.R. § 195.402(a) all pipeline from the Donkey Creek pump station upstream to the upstream end of the furthest upstream segment of 10-inch pipe;
2. With respect to Item 3 of the Notice, pressure test all pipeline segments that have not been previously pressure tested in accordance with 49 C.F.R. § 195 Subpart E;
3. With respect to Item 10 of the Notice, reduce the MOP of the following line segments so that the MOP of these segments are in accordance with 49 C.F.R. § 195.406:
  - a. The Twenty Mile station to Guernsey station section;
  - b. The Highway 450 to 12" Junction section; and
  - c. All other line sections that do not have adequate records to certify the yield strength of the pipe contained in each section.

Reduce the set pressure for all pressure control devices that protect each of the above

line sections to a pressure that is commensurate with the MOP;

4. With respect to Item 11 of the Notice, either attend or monitor the Highway 14-16 station during operation per the requirements of 49 C.F.R. § 195.408(b)(1);
5. With respect to Item 13 of the Notice, test and calibrate all pressure control devices per the requirements of 49 C.F.R. § 195.428, using proper pressure sensing equipment;
6. With respect to Item 14 of the Notice, begin monthly inspection, for the Sussex breakout tank, as per section 4 of API Standard 653, incorporating a checklist of those items listed under paragraph 4.3.1.3 of section 4 API Standard 653. Maintain records of all such inspections as required under 49 C.F.R. Part 195;
7. With respect to Item 16 of the Notice, provide increased security at the Elk Creek station per requirements of 49 C.F.R. § 195.436;
8. Maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Director, Western Region, PHMSA. Costs shall 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; and
9. Within 60 days of receipt of the Final Order, submit documentation of procedures, costs and evidence of actions taken to the Director, Western Region, Pipeline and Hazardous Materials Safety Administration, 12300 West Dakota Avenue, Suite 110, Lakewood, Colorado 80228. Please refer to CPF No. 5-2004-5010 on any correspondence or communication in these matters.

The Director, Western Region, may grant an extension of time to comply with any of the required items upon a written request timely submitted by Respondent demonstrating good cause for an extension.

Failure to comply with this Order may result in the assessment of civil penalties of not more than \$100,000 per day and in referral to the Attorney General for appropriate relief in a United States District Court.

#### AMENDMENT OF PROCEDURES

Items 5(a-b), 6(a-g), 7(a-d), 8, and 9 of the Notice alleged inadequacies in Respondent's procedures/plans and proposed to require amendment of Respondent's procedures to comply with the requirements of 49 C.F.R. §§ 195.266(a), 195.302(a), 195.402(c)(3, 7, 8, 11,13), 195.403(b)(1), 195.404(a)(1), 195.422(a-b), 195.559(a-f), 195.561(a-b), 195.563(a-e), 195.567(a-c), 195.573(e), 195.583(a-c), and 195.589(c). Respondent did not contest the Items in the Notice of Amendment with the exception of Items 6(d) and 7(b).

In its Response, Respondent submitted copies of its amended procedures or information with respect to Notice Items 5(a), 6 (c-d), 7(d), and 8, which Western Region, PHMSA, reviewed. Accordingly, based on the results of this review, I find that Respondent's procedures as described in the Notice were inadequate to ensure safe operation of its pipeline system, but that respondent has provided information and/or corrected the identified inadequacies. No need exists to issue an Order Directing Amendment with respect to Items 5a, 6(c-d), 7d, and 8.

However, with respect to Notice Items 6(a-b, f), 7(a), and 9, Respondent's Response indicated that these Notice Items were not yet complete and submissions were not included in the Response. With respect to Notice Items 5b, 6(e,g), 7(b-c), although Respondent submitted amended procedures/plans to the Western Region, PHMSA, these procedures/plans do not address all of the inadequacies described in the Notice. Accordingly, I find that Respondent's procedures as described in the Notice are inadequate to ensure safe operation of its pipeline system. Pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. §190.237, Respondent is ordered to make the following revisions to its procedures:

1. Amend its procedures to adequately list pressure test requirements (Notice Item 5b);
2. Amend its corrosion control procedures to adequately address coating requirements (Notice Item 6a);
3. Amend its corrosion control procedures to adequately address the inspection of pipe prior to lowering it into the ditch (Notice Item 6b);
4. Amend its corrosion control procedures to adequately describe how and when external corrosion control deficiencies must be corrected (Notice Item 6e);
5. Amend its corrosion control procedures to adequately address atmospheric corrosion monitoring frequency (Notice Item 6f);
6. Amend its corrosion control procedures to adequately address appropriate records retention time (Notice Item 6g);
7. Amend its startup procedures to adequately describe startup and shutdown processes (Notice Item 7a);
8. Amend its procedures to require attendance or monitoring of the Highway 14-16 pump station during startup and shut-in operations (Notice Item 7b);
9. Amend its procedures to minimize the likelihood of accidental ignition near areas identified under 49 C.F.R. §195.402(c)(4). Its procedures should define areas that would require immediate response in the case of failure or malfunction. It must have procedures for preventing accidental ignitions at those locations. Ignition sources may include but are not limited to: operating internal combustion engines; activities that could generate static electricity or electrical arcing; welding, cutting, and other

hot work; using certain non-approved electric equipment (flashlights, power tools/equipment, etc.); working on motors or appurtenances; working inside pipeline buildings; use of spark-producing hand tools; engine exhaust stack temperatures. Respondent should maintain restricted access to hazardous areas, including safety zones for vehicular and air space domains (Notice Item 7c);

10. Amend its maps and records to ensure that the location and identification of pipeline facilities are updated and complete (Notice Item 9); and
11. Within 30 days following receipt of this Order, submit the amended procedures to the Director, Western Region, PHMSA.

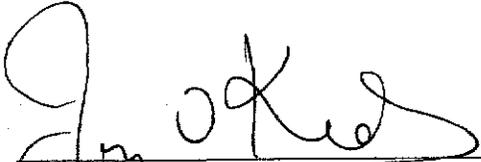
The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by Respondent demonstrating good cause for an extension.

Failure to comply with this Order Directing Amendment may result in the assessment of civil penalties of up to \$100,000 per violation per day, or in the referral of the case for judicial enforcement.

#### WARNING ITEMS

The Notice did not propose a civil penalty or corrective action for Notice Items 4 (49 C.F.R. §§ 195.402(a) and 195.569), 15 (49 C.F.R. § 195.434), and 18 (49 C.F.R. § 195.583); therefore, these are considered warning items. Respondent is warned that if it does not take appropriate action to correct these items, enforcement will be taken if a subsequent inspection reveals a violation.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of the petition automatically stays the payment of any civil penalty assessed. All other terms of the Order, including any required corrective action and amendment of procedures, remain in full effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective on receipt.

  
 Theodore L. Willke  
 Acting Associate Administrator  
 for Pipeline Safety

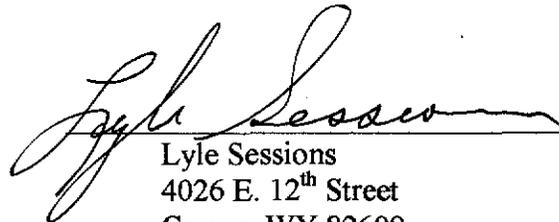
DEC 11 2008

Date Issued

AFFIDAVIT OF LYLE SESSIONS

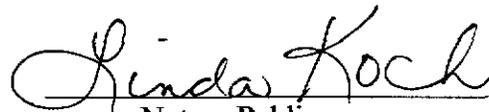
I, Lyle Sessions, herby depose and state as follows:

- 1. I worked for Belle Fourche Pipeline Company from April 1966 until my retirement in January 2007. I started out as a gauger and became Superintendent of Operations with oversight over and in charge of all pipeline operations in about 1981, or for about 25 years. I am intimately familiar with the record-keeping practices and operational methods of Belle Fourche during my employment.
- 2. I have been shown the three maps which are appended as Attachments 1, 2 and 3, and I recognize them as copies of portions of the mainline maps which Belle Fourche has kept and keeps in its office in the ordinary course of business.
- 3. It was and is the practice to keep pipeline maps in the office which show the location and other relevant information concerning the pipeline, including the pipe diameter, wall thickness and tensile strength rating of the pipeline. Such entries would be made at the time of construction and, when this line was constructed forty years ago, were the main source of information as to pipe diameter, thickness and grade.
- 4. In addition, during a repair I recall seeing mill markings on pipe in the area of the Attachment 1 indicating that the pipe grade was "X52", as shown on the office map. During my 25 years of overseeing all operations of Belle Fourche, I never saw or heard of the office map being inaccurate as to the information on it regarding pipe diameter, thickness and grade.
- 5. If it became necessary to repair leaks by replacing a section of pipe, it was the invariable practice to use the same grade of pipe and I verified the grade and wall thickness from the office map information.

  
 \_\_\_\_\_  
 Lyle Sessions  
 4026 E. 12<sup>th</sup> Street  
 Casper, WY 82609

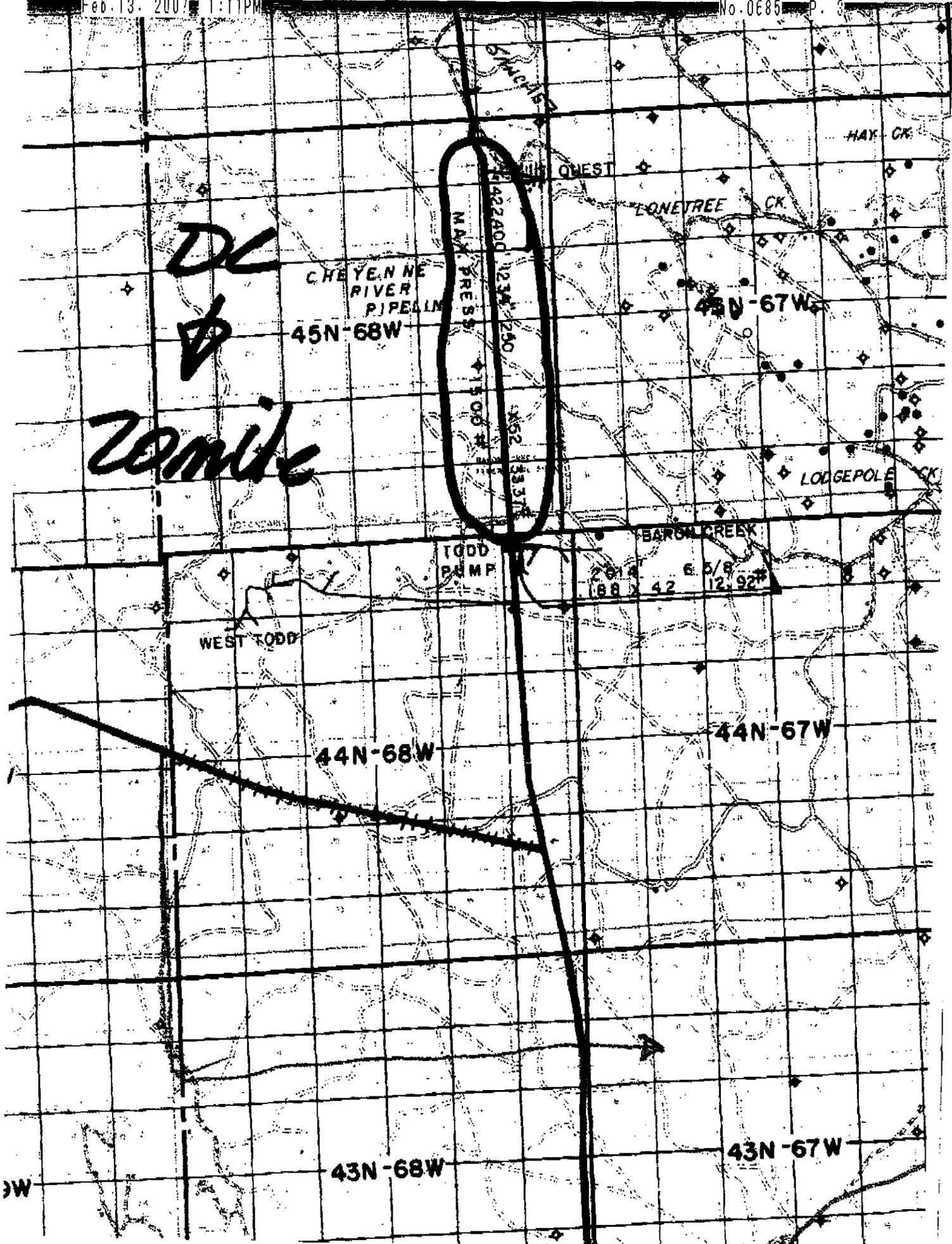
State of Wyoming            )  
   ) ss  
 County of Natrona         )

Subscribed and sworn to before me this 14<sup>th</sup> day February, 2007.

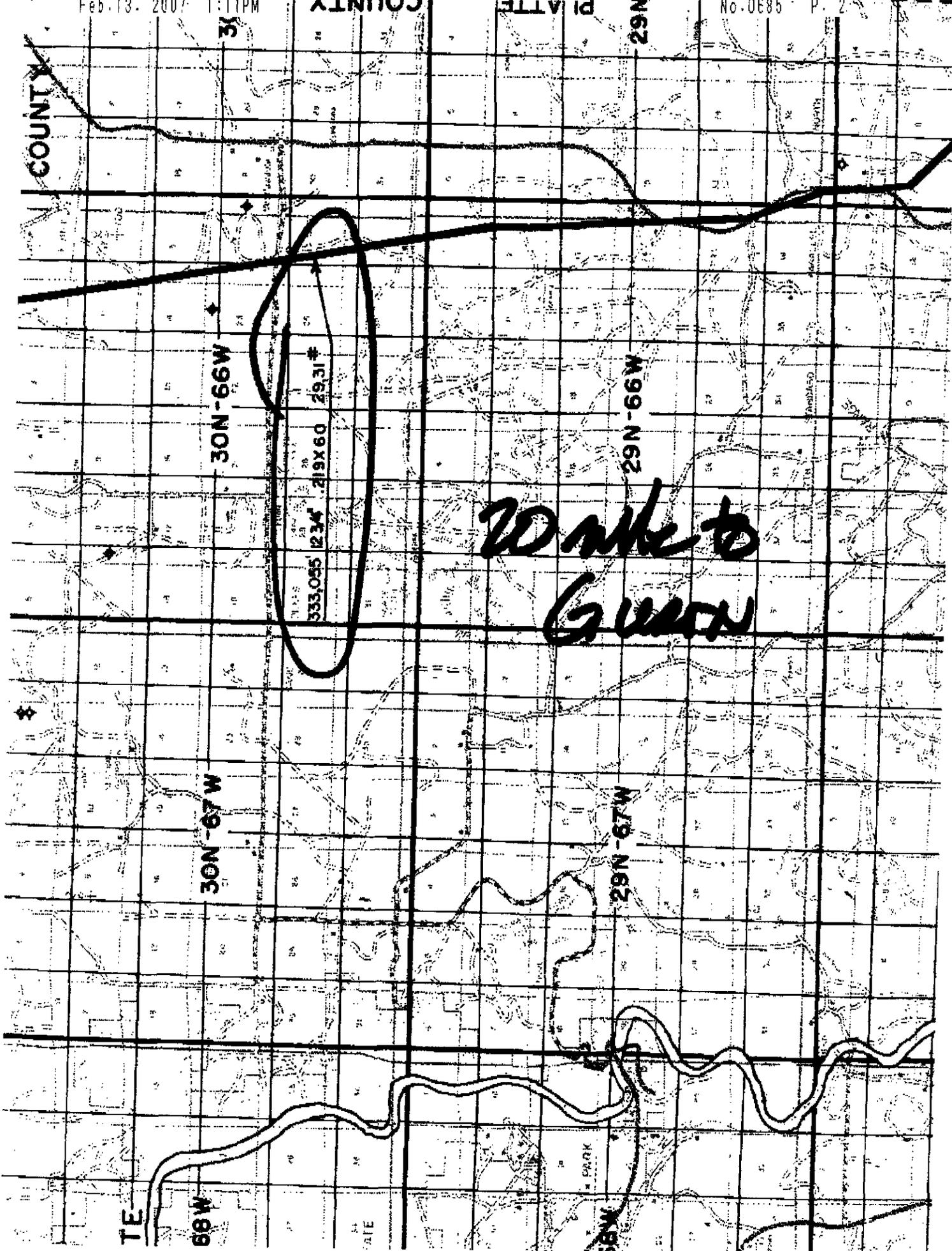
  
 \_\_\_\_\_  
 Notary Public



05/24/2007 -



COUNTY



20 miles to Guern

333,055 12.34' 219X60 29.31#

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29N-66W

30N-67W

28N-67W

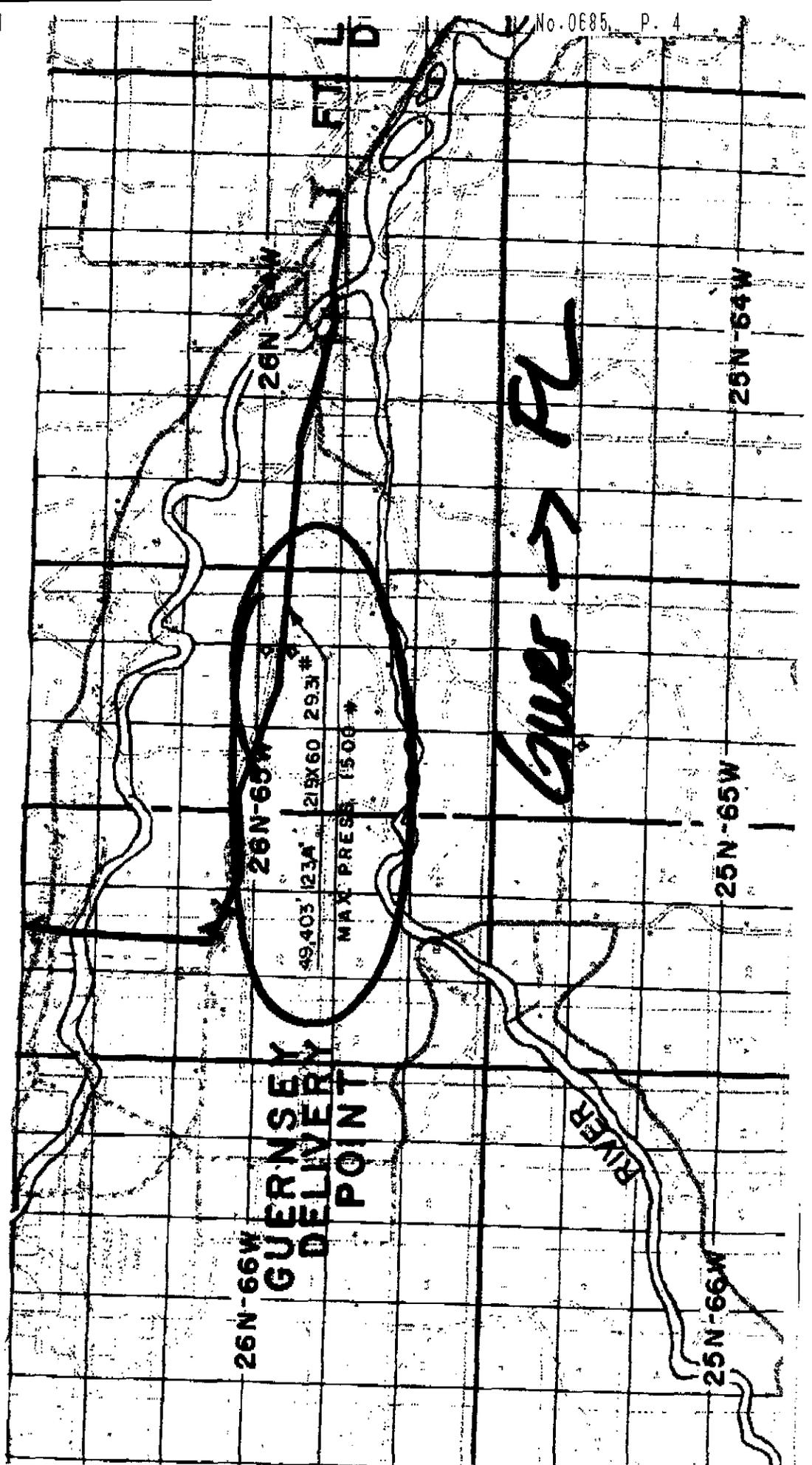
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ATTACHMENT 2



# Belle Fourche Pipeline Company

455 N. Poplar Street

P.O. BOX 2360  
CASPER, WY 82602  
307-237-9301  
307-237-3164FA

February 15, 2007

Chris Hoidal  
Director, Western Region  
PHMSA  
12300 W. Dakota Ave. Ste 110  
Lakewood, CO 80228

VIA OVERNIGHT SERVICE

Re: CPF No. 5-2004-5010  
Compliance Order

Mr. Hoidal:

In accordance with the Compliance Order in the above referenced matter, BFPL submits the following:

As to Item 1 of the Notice which includes sub-numbers 1 and 2 of Item 3, BFPL ceased crude oil movements from Alzada to Donkey Creek in June of 2004. BFPL subsequently completely removed from service all 10" and 8" pipeline segments from service upstream of Donkey Creek in October 2006. Only the Belle Creek to Alzada 8" segment remains in service as a gathering line.

As to Item 11 of the notice, BFPL ceased using the Hwy 14-16 station effective October 2006.

As to Item 13 of the notice, BFPL put procedures in place in 2004 to test and calibrate overpressure devices. An example of the form is included.

As to Item 14 of the notice, BFPL began inspecting breakout tanks, including Sussex Station, monthly per API 653, Section 4.3.1.3 in 2004. An example of the form is included.

Chris Hoidal, Director  
February 15, 2007  
Page 2 of 2

As to Item 16 of the notice, BFPL ceased operating the Elk Creek station in October 2006. This facility only received trucked oil from June 2004 to October 2006.

As to Item 3 (sub-number 3) and Item 10, BFPL is concurrently filing a petition for reconsideration.

Sincerely,

A handwritten signature in cursive script that reads "Robert Stamp".

Robert Stamp  
Superintendent of Engineering

Handwritten initials, possibly "RS", written in cursive below the typed name.

**Belle Fourche Pipeline**

Form 12/05

**Overpressure Device Inspection - Donkey Creek**

Location	Unit	Device (i.e. Murphy)	Function (i.e. Low Shutdown)	Setting (psi)	Calibration Point (psi)	Comment or changes made	Inspector	Date
----------	------	-------------------------	---------------------------------	------------------	----------------------------	----------------------------	-----------	------

DC	Unit #1	Murphy	High Discharge					
			Low Discharge					
		PLC	Vibration					
			Winding Temp					
			Inboard Mtr Brg					
			Outboard Mtr Brg					
			Inboard Pump Brg					
			Outboard Pump Brg					
			Case Temp					
DC	Unit #2	Murphy	High Discharge					
			Low Discharge					
		PLC	Vibration					
			Winding Temp					
			Inboard Mtr Brg					
			Outboard Mtr Brg					
			Inboard Pump Brg					
			Outboard Pump Brg					
			Case Temp					
DC	Unit #3	Murphy	High Discharge					
			Low Discharge					
		PLC	Vibration					
			Winding Temp					
			Inboard Mtr Brg					
			Outboard Mtr Brg					
			Inboard Pump Brg					
			Outboard Pump Brg					
			Case Temp					

MAOP for 12" to Guernsey = 1152 psi.

Complete check list below, check device function (shutdown), verify SCADA reading accuracy, adjust device if necessary.

**Checklist - Inspect a Pressure Switch**

- \_\_\_\_\_ 1.1 Ensure safe work permits, lockout/tagout, personal protective equipment, gas detectors, etc. are in place.
- \_\_\_\_\_ 1.2 Conduct a pre-job meeting, if necessary with personnel involved in pressure switch maintenance.
- \_\_\_\_\_ 2.0 Review the current loop components and maintenance history for that pressure switch application:
- \_\_\_\_\_ 3.0 Contact DC center to advise them that the pressure switch will be inspected.
- \_\_\_\_\_ 4.0 Visually inspect pressure switch for leaks, corrosion or damaged wiring
- \_\_\_\_\_ 5.0 Isolate or lock out (if possible) the associated process: follow lockout procedures as needed.
- \_\_\_\_\_ 5.1 Verify that there is no pressure on the switch.
- \_\_\_\_\_ 6.0 Connect external pressure equipment. Pressure up the switch, check reading against gauge and against SCADA reading.
- \_\_\_\_\_ 6.1 Adjust switch if necessary. Verify electrical contact at shutdown point.
- \_\_\_\_\_ 6.2 Repair or replace damaged components if needed.
- \_\_\_\_\_ 7.0 Reset pressure switch and verify that all equipment is returned to normal operating condition:
- \_\_\_\_\_ 7.1 Remove locks and tags.
- \_\_\_\_\_ 8.0 Notify DC that inspection is complete.

**Monthly Tank Inspection Report**  
**Storage Tank or Pressure Vessel**  
**PL-509 (Rev. 01/05)**

**Form No. PL-509**

**(Page 1 of 2)**

**Tank Information:**

Tank Location:	Tank No.:
Inspector:	Date:
Service/Product:	Roof Type:

**Inspections:**

(Place an "X" in the Appropriate Box)	Deficiencies			Schedule Repair (If Yes)
	Yes	No	N/A	
<b>Surrounding Area:</b>				
1. Damaged dike wall, excess vegetation				
2. Firewall drain inoperative or leaking				
3. Product on ground or on ground water				
4. Materials stored inside operating dike wall				
<b>Tank Foundation:</b>				
5. Tank contents leaking onto foundation				
6. Broken concrete, washout(s) under tank				
7. Tank settlement				
8. Drainage toward tank				
9. Corrosion or deterioration of chime				
10. Chime covered by soil, gravel, vegetation				
<b>Tank Shell:</b>				
11. Leaks in shell or roof drain				
12. Shell deformation - inward or outward				
13. Deformation around roof to shell joint				
14. Significant corrosion, paint failure				
<b>Appurtenances:</b>				
15. Valves or flanges leaking or broken				
16. Mixer inoperative or leaking				
17. Stairway, railing or platforms need repair				
<b>Insulation:</b>				
18. Damaged areas, corrosion underneath				
19. Not sealed at top, water intrusion				
<b>Tank Roof:</b>				
20. Dips or buckling				
21. Significant corrosion, paint failure				
22. Roof sump inoperative, needs cleaning				
23. Roof drain system inoperative, leaking				
24. Floating roof not level				
25. Oil, water or dirt on floating roof*				
26. Damage to floating roof seal*				

\*On an Internal Floating Roof, perform this observation only (a) when it can be done safely without a fall protection harness, and (b) when visual access is available simply by lifting or opening a roof hatch.

# Belle Fourche Pipeline Company

455 N. Poplar Street

P.O. BOX 2360  
CASPER, WY 82602  
307-237-9301  
307-237-3164FAX

February 15, 2007

Chris Hoidal  
Director, Western Region  
PHMSA  
12300 W. Dakota Ave. Ste 110  
Lakewood, CO 80228

VIA OVERNIGHT SERVICE

Re: CPF No. 5-2004-5010  
Amendment of Procedures

Mr. Hoidal,

In response to the Amendment of Procedures requirement in the above referenced matter, BFPL submits the following:

List Item 1 – Notice Item 5(b): See Section 5.13 of the O&M Manual, Hydrostatic Testing.

List Item 2 – Notice Item 6(a): See Section 5.6.4 of the O&M Manual, Pipeline Coating Guideline.

List Item 3 – Notice Item 6(b): See Section 5.6.4 of the O&M Manual, Pipeline Coating Guideline, Inspection paragraph.

List Item 4 – Notice Item 6(e): See Section 5.6.1 of the O&M Manual, External Corrosion, Corroded Pipe paragraph.

List Item 5 - Notice Item 6(f): See Section 5.6.3 of the O&M Manual, Atmospheric Corrosion.

List Item 6 - Notice Item 6(g): See Section 5.6.1 of the O&M Manual, External Corrosion, Recordkeeping paragraph.

List Item 7 - Notice Item 7(a): See Section 4.3 of the O&M Manual, Start up Procedures and Section 4.4 Shut down procedures.

List Item 8 - Notice Item 7(b): Hwy 14-16 Station is no longer in operation.

List Item 9 - Notice Item 7(b): See Section 7.1 of the O&M Manual, Emergency Procedures. This section deals in general with immediate response areas and identifies those areas as per 195(c)(4).

List Item 7 - Notice Item 7(a): Detailed alignment sheets for PHMSA jurisdictional pipeline segments in Wyoming were created through 2004 and 2005. The sheets update previous records and maps, identify pipeline facilities and provide up to date aerial imagery of the ROW.

Copies of all of the foregoing are attached, except the sheets for Item 7 (a), which are large format (24 x 32) and not suitable for inclusion to this letter. However, PHMSA personnel have seen the alignment sheets in the Casper office.

Please contact me if you have any questions.

Sincerely,



Robert Stamp  
Superintendent of Engineering



5.13

**Hydrostatic Testing**

Reference: 49 CFR  
 195.300

Pressure testing is a widely used and accepted method to determine the structural integrity of pipelines. Structural integrity is proven by raising the pressure level of the pipeline to a level above the maximum operating pressure, under no-flow conditions, for a fixed time.

The pressure test reveals any harmful manufacturing, fabrication or time dependent defects that could cause service failures.

Time dependent defects include wall loss due to corrosion existing at the time of the test.

5.13.1

**Safety**

The Safety Manual shall be followed.

Extra safety precautions are necessary when any exposed piping is being pressure tested. Defects that might cause piping failures normally show up during pressure testing.

Although failures seldom occur during pressure testing, take every reasonable precaution to avoid injury due to piping or testing equipment failure.

5.13.2

**Component Testing**

A "component" means any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures. Each hydrostatic test must test all pipe and attached fittings, including components, unless the component is the only item being replaced or added to the pipeline system, and the manufacturer certified that either:

- The component was hydrostatically tested at the factory; or
- The component was manufactured under a quality control system that ensures each component is at least equal strength to a prototype that was hydrostatically tested at the factory.

Although pipe is listed as a component, a hydrostatic test of pipe at the mill as part of the manufacturing process is not acceptable as an exclusion to the hydrostatic testing as outlined above.

5.13.3

**Testing Procedure**

Pressure testing is guided by API Recommended Practice 1110, Pressure Testing of Liquid Petroleum Pipelines

Pressure testing of piping for hazardous liquid jurisdictional pipelines must meet 49 CFR Part 195, Subpart E – Pressure Testing.

In-place pressure testing is required for any pipeline extension or replacement before returning the system to service **except** if the individual joints of the pipe have been previously tested to the applicable requirements and documentation is available.

*NOTE: All tie-in welds and all girth welds in replacement pipe must be radio graphed.*

Pressure testing is not required for a single component (new) other than pipe that is added or replaced if the manufacturer certifies either:

- 1) the component was hydrostatically tested to at least the minimum test pressure required below or
- 2) the component was manufactured using a quality control system ensuring each item manufactured is at least equal in strength to a prototype that was tested to at least the minimum test pressure required below.

Pressure testing of used components that are installed in a pipeline system, whether or not installed as a single component, is required (shop test is acceptable provided it meets the minimum testing requirements).

**Test Medium**

The test medium should be water. The water may require filtering and/or treating to minimize pipe and appurtenance damage.

Use other test mediums, such as crude oil with a Reid vapor pressure less than 7 psia, only as allowed by applicable regulations and with Management approval.

An inert gas such as nitrogen, may be used with Region management approval under certain conditions where testing with water is not feasible and applicable regulations allow, although it is strongly discouraged due to the hazards of stored energy which exist in compressed gas.

**CAUTION:**

- Air should NOT be used as a test medium
- If nitrogen or other inert gas is used, special precaution shall be taken to assure safety of all personnel.

**Test Pressure**

The highest, economically practical test pressure is generally preferred.

The minimum test pressure in the test section is 1.25 times the maximum operating pressure for that test section. Or, the minimum test pressure is the minimum pressure specified by the applicable regulation.

The maximum test pressure should not exceed any of the following:

- a) A pressure producing a calculated pipe hoop stress of 95% SMYS based nominal wall thickness.

*CAUTION: When testing at pressures exceeding 90% SMYS of the pipe, prevent overstrain of the pipe. For example, limit bending of the pipe using properly spaced supports.*

**Test  
Duration**

- b) The ANSI test pressure limits for any fitting in the test section.
- c) API Specification 6D, Specification for Pipeline Valves, test pressure limits for the bodies of any valves in the test section.
- d) API Specification 6D seat test pressure limits for any closed valve in the test section during the test. Unless action is taken to limit the pressure differential across the valve to the seat test pressure limit. Or, unless a higher differential pressure is authorized by the manufacturer.
- e) Manufacturer's recommended maximum test pressures for appurtenances, such as meters.

Component pressure test by Manufacturer, such as pumps tested at 1.5 times their pressure ratings.

**Strength Test**

Liquid pipeline pressure tests shall be maintained at or above the test pressure for at least four (4) continuous hours.

**Leakage Test**

If the tested pipeline segment cannot be visually inspected during the pressure test, an additional four (4) continuous hours of testing are required.

The test pressure during the additional four (4) hours may be reduced to 110% of the maximum operating pressure.

More stringent requirements may be specified when prudent engineering justifies the additional time and/or costs.

**Disposal of Test Medium**

Disposal of hydrotest water will always require a permit or authorization of some sort. Permits vary in complexity based on the state or locality in which the facility is located, as well as whether the water is being discharged to a POTW (sanitary sewer), to a water body or to land.

**Contact the Company's Environmental Representative for guidance on disposal of test medium.**

**Test Results Records**

Document hydrostatic test – Form PL-511 (Hydrostatic Test Report) or equivalent with supporting documentation attached:

- Pressure recording charts (signed & dated)
- Form PL-511, "Hydrostatic Test Report"
- Temperature recording charts or documented temperature changes
- Test instrument calibration data:
  - a. Certification of deadweight tester
  - b. Certification of pressure recorder
  - c. Certification of temperature device
- Description of test equipment used (pump type, mfr., model) on Form PL-511.
- Sketch or drawing which specifically and clearly shows the extent of the pipe that was hydrotested.
- An explanation of any pressure discontinuities, including test failures that appear on the pressure recording charts.
- Where differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section is required.
- Whenever pretested components are added, a documented statement of no seeps during startup.

**5.13.4 Company Responsibilities**

The Company representative should assure the specified test requirements are appropriate before starting the test. In addition to assuring the proper test pressure and test duration, the following should be reviewed:

- a) Relief valves are removed or blinded.
- b) Ratings of valves, blinds, flanges or other components are adequate for the test pressure.
- c) Any closed valve's specified seat test pressure will not be exceeded
- d) Location of buried flanges and fittings that could leak during pressure testing.

## 5.13.5

**NOTES:**

- e) Pressure testing fabricated and replacement piping before painting, if practical.
- f) Adequate support of fabricated and replacement piping once filled with water.
- g) Disconnected or isolated low pressure filling lines and appurtenances or other sections not to be tested.
- h) High points of the test section should be identified for venting trapped air.
- i) Test water's chloride content should be less than 100 ppm for testing austenitic stainless steel piping.

***Pressure Validation***

- New fabricated and replacement piping that can be visually observed during testing may be pressured directly to the test pressure.
- Existing, buried pipe sections should first be pressured to either the historical line pressure or the maximum operating pressure, MOP, of the section. This pressure should be held for two hours to validate the pipeline's previous operating pressure.
- After pressure validating, the pressure should be increased to the test pressure.

***Replacement Pipe***

Replacement piping may be tested using multiple pipe lengths welded together.

Pressure tested replacement piping must be permanently marked using paint or tags. Marking must be traceable to pressure test records.

***Dyes & Tracer Gas***

Consider adding fluorescent dye and SF6 tracer gas to test water to aid locating buried piping leaks.

- Large leaks (water goes to surface) can be located visually by flying, driving or walking the pipeline.
- Small leaks (water does not go to surface) can be difficult to locate.
- Consider isolating the leak section to a manageable length using ice plugs. Then probe the pipeline to locate the SF6 tracer gas leak site. If tracer gas does not locate the leak, excavate the leak section.

***Temporary Repair***

Temporary leak repairs, such as clamps or patches (where allowed), may be considered when testing older pipelines.

**Notes (continued)*****Permanent repairs***

Permanent repairs of leaks should be made as soon as practicable.

If any old clamps are uncovered in the process of repairing the pipe line, these should also be replaced with permanent repairs.

**5.13.6*****Planning  
Guidelines***

Planning pipeline pressure testing could include the following:

- Water source and disposal. Check with Company's Environmental Representative for requirements in handling water disposal, including necessary permitting.
- Dye source and injection method. Tracer gas contractor.
- Testing contractor. Mechanical contractor and subcontractors, such as nondestructive testing and asbestos removal.
- Ice plug contractor.
- Cleaning and sweeping pigs.
- Tested pipe, repair fittings, blinds, bolts, gaskets, and coatings.
- Pipeline contacts, such as scheduling, Area personnel, operations foreman and project coordination.
- Land agent available during testing.
- Inspectors.
- Radios.
- Alignment sheets and profiles.
- Valves located and identified. Assure valves with seals that may allow water leakage into body cavities are set to fill body cavities preventing leakage to empty body cavities.

	<p>shall be documented (PL 517) and remedied prior to the next scheduled inspection:</p> <ul style="list-style-type: none"> <li>• Noticeable metal loss or pitting</li> <li>• Lack of coating or deteriorated coating at soil/air interface</li> <li>• Dents, gouges, grooves or other mechanical damage</li> <li>• Visible cracking</li> <li>• Water entrapment or potential areas for water entrapment</li> </ul>
<p><b>5.6.4</b> <b><i>BFPL / Bridger Pipeline Coating Guideline</i></b></p>	<p>This is intended to be a basic guideline for coating selection and use on most Bridger and BFPL projects. This is not a detailed instruction manual. <b>Always</b> follow the manufacturer's instructions and recommendations. If you are uncertain as to the application or there are unusual circumstances, consult your supervisor, the engineering staff and/or manufacturer's representative to select the proper product and application procedure. (Where coating options are listed, the list is in order of preference).</p>
<p><b><i>Coating Selection</i></b></p>	<p><b>Coating Selection for New Pipe:</b></p> <ul style="list-style-type: none"> <li>• New pipe coating specification is a factory applied, single layer FBE, 14 to 16 mils.</li> <li>• Weld end joints shall be coated with a heat shrink sleeve on a Commercial Blast surface.</li> <li>• New pipe used in bores, river crossings (weighted) or other abrasive service is a factory applied, 2 layer FBE coating. Weld end joints shall be field applied abrasive surface FBE (Denso Brush Grade or Powercrete) on a Commercial Blast surface.</li> <li>• New pipe should be stored on padded racks (not on the ground), with poly rope protectors or padded spacers. FBE coating is fairly UV stable, but pipe should be covered or indoors if at all possible.</li> </ul>
	<p><b>Pipe and Coating Repairs – Sections over 20 feet in length:</b></p> <ul style="list-style-type: none"> <li>• A factory applied FBE coated pipe (same as new pipe spec) or,</li> <li>• Heat shrink sleeves on Commercial Blast surface or,</li> <li>• A field applied 2 part epoxy applied on a Commercial Blast surface or d) For 4" and 6" non-DOT, low pressure (suction or gravity) pipelines only, a cold applied tape over primer on a power tool SSPC-SP11 surface.</li> </ul>
	<p><b>Pipe and Coating Repairs – Sections less than 20 feet in length:</b></p>

	<ul style="list-style-type: none"> <li>• A field applied, 2 part epoxy applied on a Commercial Blast surface or,</li> <li>• Heat shrink sleeves on a Commercial Blast surface or,</li> <li>• Wax tape over wax primer on a Commercial Blast surface or,</li> <li>• For 4" and 6" non-DOT pipelines only, a cold applied tape over primer on a Commercial Blast surface or a power tool SSPC-SP11 surface.</li> </ul>
	<p><b>Scratches, Nicks and Minor Coating Holidays:</b></p> <ul style="list-style-type: none"> <li>• Heat shrink sleeve. Use a full sleeve, not a patch and pipe must be fully exposed or,</li> <li>• Wax tape over wax primer (this is the only choice for damaged coal tar coatings, see 5(i) or,</li> <li>• Cold applied tape over primer or,</li> <li>• Mastic or filler tape with an outer wrap (for fully exposed pipe).</li> <li>• Procedure: <ol style="list-style-type: none"> <li>1. Determine that there are no dents, corrosion or equipment damage to the pipe.</li> <li>2. Area of holiday or nick should be cleaned to remove dirt, oil, grease, moisture, etc. Exposed pipe surface should be cleaned to bare metal and abraded, if possible, to give the surface a profile.</li> <li>3. Whatever coating repair is selected, it must adhere to the old coating well.</li> </ol> </li> </ul>
	<p><b>Full Encirclement Sleeve Repair Coating:</b></p> <ul style="list-style-type: none"> <li>• A cold applied wrap or heat shrink sleeves on a primed, Commercial Blast surface. <ol style="list-style-type: none"> <li>1. Prepare surface to a Commercial Blast.</li> <li>2. Apply primer over the entire surface and on the old coating to transition. (See specific procedure for coal tar coatings below).</li> <li>3. Install a mastic wedge (filler tape) next to the girth welds to cover the weld and fill in air pockets and cavities.</li> <li>4. Install heat shrink sleeves or</li> <li>5. Wrap the sleeve repair with cold applied tape, preferably Denso PolyGuard RD6. Wrap should transition over old coating at least 4".</li> </ol> </li> <li>• A field applied, 2 part epoxy applied on a Commercial Blast surface.</li> </ul>

	<p><b>Specific to Existing Coal Tar Coatings:</b></p> <p>Because of the deterioration of the old coal tar coatings (i.e. Butte and Poplar), a transition coating is specified:</p> <ul style="list-style-type: none"> <li>• The transition from any new coating to old coal tar coating will be wax tape over wax primer (Denso Paste). Apply the new coating within 4" of the old coal tar and apply the transition coating at least 4" over the new and the old coating.</li> </ul>
	<p><b>Valves and fittings:</b></p> <ul style="list-style-type: none"> <li>• A field applied, 2 part epoxy applied on a Commercial Blast surface or,</li> <li>• Wax tape over wax primer on a Commercial Blast surface, with an outer wrap or,</li> <li>• Two layers of cold applied mastic on a Commercial Blast surface with an outer wrap.</li> <li>• Surfaces can be power tool cleaned (SSPC- SP11) if blasting is not possible.</li> </ul>
<b>Surface Preparation</b>	<p>Whether installing new coating on new pipe or repair old coating on existing pipe, surface preparation is critically important. Following are guidelines and requirements for surface preparation:</p>
	<ul style="list-style-type: none"> <li>• <b>Commercial Blast (SSPC #6, NACE #3) is the minimum, preferred standard for all coatings and repairs.</b> A Near White Blast (SSPC #10, NACE #2) is the preferred surface for field application of epoxy. There are achieved by abrasive blasting. Blasting media should be copper slag.</li> <li>• If blasting equipment is not available, or not practical, an alternative, SSPC – SP11, Power Tool Cleaning to Bare Metal can be used for coating sections less than 20 feet and on pipe 8" in diameter or less. This is the removal of all rust scale, mill scale, loose paint, and loose rust to the degree specified by power impact tools, power grinders, power sanders or by a combination of these methods to produce a surface profile of at least 1 mil. An Elcometer with Testex tape can be used to check the profile. The pipe should have a pronounced metallic sheen and also be free of oil, grease, dirt, soil, salts and other contaminants. <b>Surface should not be buffed or polished smooth. Do not use a wire brush.</b></li> </ul>
<b>Rock Shield</b>	<p>Rock shield should be used at the construction inspector's discretion. Areas where the size of backfill material, the coarse or sharp nature of the backfill material or the native material could cut or scar the coating</p>

	may need rock shield. Products include Tuff'n'Nuff or GridGuard.
<b>Inspection</b>	<p>All coatings and surface preparation should be inspected through every step of the application process. It is the construction inspector's job to make sure that the correct products are used, procedures are followed correctly, that the ambient conditions are within tolerance for the products.</p> <p>Formulation and application of factory coated FBE is the responsibility of the coating mill. Once off of the truck, the inspection and care of the pipe is the construction inspector's responsibility. Pipe will be handled so as not to damage the coating. Padded forks, padded supports, poly rope, poly straps, etc should be used to prevent damage.</p> <p><b>All coating on buried pipe shall be inspected immediately prior to the pipe being lowered into the ditch, or on smaller sections, prior to backfilling.</b></p> <p>Detector voltage (jeep) voltage should be set for 125 volts/mil of coating for inspection unless specified by manufacturer.</p> <p>Repairs to damaged areas should be made according to coating repair specs in this section. Records of the location, description and repair of each coating holiday will be kept with the permanent construction records.</p>
<b>Air / Soil Interface</b>	Coating at the air/soil interface of all pipes should be Stopaq CZ 70 mil wrap. 18" below the soil surface and 12" above the soil surface.
<b>Product Listing</b>	<p><u>Two part epoxy coating</u> – Protal 7200 or 7125 (Cold Temp) on a Commercial Blast surface.</p> <p><u>Heat Shrink Sleeve</u> – Canusa Wrapid Sleeve on a Commercial Blast surface. Transition to old coating should be 4-6 inches. Overlap per manufactures spec.</p> <p><u>Wax tape</u> – Denso Densyl wrap over Denso Paste (primer). (or Trenton #1 Wax Tape). Procote PK50 or Denso Glass Outer Wrap. Surface should be commercial blast or SP11 prepped. Transition to old coating should be 4-6 inches.</p> <p><u>Cold applied tape over primer</u> – SCAPA 35 mil 4" Tape over primed surface. Surface should be commercial blast or SP11 prepped. Other products of similar thickness and durability can be used such as PolyGuard RD6, lap bond tape or Stopaq.</p>

	<p><u>Mastic</u> – CA9 (coal tar based) or CA14 (asphalt based). Surface should be commercial blast or SP11 prepped. An outer wrap (#400 mastic wrap) or woven fiberglass should be used.</p>
<p><b>Specification Listing</b></p>	<p>For reference, these are industry standards to be followed in the selection and preparation of coatings:</p> <p>SSPC 2 - Hand Tool Cleaning  SSPC 3 - Power Tool Cleaning  SSPC 11 - Power Tool Cleaning to Bare Metal  SSPC 10, NACE No. 2 – Near White Metal Blast Cleaning  SSPC 6, NACE No. 3 – Commercial Blast Cleaning  SSPC 7, NACE No 4 – Brush Blast Cleaning  NACE RP0287 – Determination of Surface Profile by Replica Tape  SSPC PA2 – Dry Film Thickness Measurement  ASTM D-1186 – Dry Film Thickness of a non-magnetic coating on ferrous substrate  NACE RP00188-99 – Holiday Testing of Protective Coatings on Conductive Substrates  NACE RP0490-01 – Holiday Testing of FBE Coatings (10-30 mils)  NDT Methods ASTM D4138-94, D3359-95, D4541, D3363-92, D2583  Materials and Coating Standards NACE RP0185-96, RP0190-95, RP0274-98, RP0375-99, RP0394-94, RP0200-00, RP0169-96.</p>

<p><b><i>Inspection of Cased Crossings</i></b></p>	<p>Company shall inspect all cased crossings annually to determine if shorts between the carrier pipe and the casing pipe exist. Shorted casings found to have a potential differential of less than 100 millivolts between the casing and the carrier pipe where the carrier pipe has a potential more positive than a minus (-) 850 millivolts, must be re-inspected within 180 days and a determination made to:</p> <ul style="list-style-type: none"> <li>• Continue monitoring said short on a annual basis</li> <li>• Clear the short by excavation and inspection of the casing. Manipulation of the pipe at the end of the casing, or repositioning the casing insulators may clear the short.</li> <li>• Inject an approved insulating material into the casing cavity, or</li> <li>• Remove, re-insulate and re-install the carrier pipe inside the casing.</li> </ul> <p>Table 5-1 offers a decision tree for the inspection and monitoring of casings.</p>
<p><b><i>Record Keeping</i></b></p>	<p>The Company will maintain a database(s) for the following:</p> <ul style="list-style-type: none"> <li>• Location of cathodic protection test stations, rectifiers, ground beds, bonds, electrical isolation devices, and anodes;</li> <li>• Location and condition of pipeline casings;</li> <li>• Locations where buried pipelines have become exposed;</li> <li>• Pipeline crossings of Navigable Waterways;</li> <li>• Overhead crossings.</li> </ul> <p>The Company will maintain records of the following for a minimum of 5 years:</p> <ul style="list-style-type: none"> <li>• Annual structure to soil potential surveys</li> <li>• Bi-monthly rectifier inspections and readings</li> <li>• Critical bond readings</li> <li>• Internal inspection of pipe removed</li> <li>• Close interval surveys</li> <li>• Shorted casing inspections</li> <li>• Atmospheric corrosion inspections</li> <li>• Any other analysis, inspection, or survey that lends itself to the demonstration of adequate cathodic protection.</li> </ul>

<p><b>5.6.2</b></p> <p><b>Internal Corrosion Control</b></p>	<p>Company has not experienced significant internal corrosion on jurisdictional pipelines and therefore does not treat specifically for internal corrosion. Any indication of internal corrosion present during internal inspection of the pipeline per the Integrity Management Plan will be addressed.</p> <p>Whenever a segment or component of a DOT jurisdictional pipeline is removed for any reason, a form PL 514 (Internal Inspection of Pipe Removed) must be filled out. Company personnel must examine the inside surfaces of the pipe or component for internal corrosion. If internal corrosion is found, adjacent areas of pipe must also be inspected. The remaining strength of should be evaluated. When the extent of internal corrosion is determined, the removed section of pipe will be replaced with pipe of similar specifications. An investigation will be conducted into the possible causes and overall extent of the internal corrosion.</p>
<p><b>5.6.3</b></p> <p><b>Atmospheric Corrosion</b></p>	<p>Pipe exposed to the atmosphere shall be painted or coated with material suitable for the prevention of atmospheric corrosion except where the environment is such that corrosion will only be light surface rust that does not affect the safe operation of the pipeline. All soil to air interfaces will be coated according to the coating recommendations in 5.6.4.</p>
<p><b>Visual Inspection</b></p>	<p>Company shall visually inspect all sections of pipe that are exposed to the atmosphere for evidence of atmospheric corrosion at least every three calendar years, but at intervals not to exceed 39 months. This inspection shall apply to all piping, valves, meters, pig launchers and receivers, manifolds and pipe spans. Any equipment, pipe supports, appurtenances, or overgrown vegetation which hinders the visual inspection shall be removed where practical. In cases where visual inspection is deemed impractical or insufficient alternative inspection methods, such as ultrasonic, should be used.</p>
	<p>The inspection shall give particular attention to the following areas:</p> <ul style="list-style-type: none"> <li>• Soil/Air interface</li> <li>• Pipe supports</li> <li>• Under insulation</li> <li>• Under disbonded coating</li> <li>• Spans/exposed line pipe</li> </ul> <p>Light surface rust, other than at the soil/air interface, is not considered a defect. The following conditions shall be considered defects, and</p>

	<p>shall be documented (PL 517) and remedied prior to the next scheduled inspection:</p> <ul style="list-style-type: none"> <li>• Noticeable metal loss or pitting</li> <li>• Lack of coating or deteriorated coating at soil/air interface</li> <li>• Dents, gouges, grooves or other mechanical damage</li> <li>• Visible cracking</li> <li>• Water entrapment or potential areas for water entrapment</li> </ul>
<p><b>5.6.4</b> <b>BFPL / Bridger Pipeline Coating Guideline</b></p>	<p>This is intended to be a basic guideline for coating selection and use on most Bridger and BFPL projects. This is not a detailed instruction manual. <b>Always</b> follow the manufacturer's instructions and recommendations. If you are uncertain as to the application or there are unusual circumstances, consult your supervisor, the engineering staff and/or manufacturer's representative to select the proper product and application procedure. (Where coating options are listed, the list is in order of preference).</p>
<p><b>Coating Selection</b></p>	<p><b>Coating Selection for New Pipe:</b></p> <ul style="list-style-type: none"> <li>• New pipe coating specification is a factory applied, single layer FBE, 14 to 16 mils.</li> <li>• Weld end joints shall be coated with a heat shrink sleeve on a Commercial Blast surface.</li> <li>• New pipe used in bores, river crossings (weighted) or other abrasive service is a factory applied, 2 layer FBE coating. Weld end joints shall be field applied abrasive surface FBE (Denso Brush Grade or Powercrete) on a Commercial Blast surface.</li> <li>• New pipe should be stored on padded racks (not on the ground), with poly rope protectors or padded spacers. FBE coating is fairly UV stable, but pipe should be covered or indoors if at all possible.</li> </ul>
	<p><b>Pipe and Coating Repairs – Sections over 20 feet in length:</b></p> <ul style="list-style-type: none"> <li>• A factory applied FBE coated pipe (same as new pipe spec) or,</li> <li>• Heat shrink sleeves on Commercial Blast surface or,</li> <li>• A field applied 2 part epoxy applied on a Commercial Blast surface or d) For 4" and 6" non-DOT, low pressure (suction or gravity) pipelines only, a cold applied tape over primer on a power tool SSPC-SP11 surface.</li> </ul>
	<p><b>Pipe and Coating Repairs – Sections less than 20 feet in length:</b></p>

<p><b>Monitoring and Inspection (Annual Surveys)</b></p>	<p>Company shall electrically inspect cathodic protection test stations on each pipeline system once each calendar year, at intervals not to exceed 15 months, to determine the effectiveness of the cathodic protection system. Annual cathodic protection inspections will include electrical inspections of cased crossings, bonds, and electrical isolation devices. Suitable documentation shall be maintained of these inspections.</p> <p>Deficiencies identified during the annual inspection will be remedied prior to the next annual inspection. If circumstances prevent the complete remediation of a deficiency prior to the next annual inspection, Company shall establish a plan to complete the remediation of the deficiency as soon as practicable.</p>
<p><b>Procedure for CP Readings</b></p>	<p>Cathodic protection test-readings will be taken by placing the half cell on the soil directly over the pipeline and connecting the wire lead from the volt meter to the test station or pipe. Care must be taken to avoid contact with the copper stud on top of the half cell while taking CP readings since body contact at this point can influence the reading. When the reading is to be taken during a maintenance inspection a steel ice pick can be used to make contact through the coating on the pipe. NOTE: Always repair any damage done to the coating during inspection.</p>
<p><b>Corroded Pipe</b></p>	<p>Pipe found to be corroded to the extent that the remaining wall thickness would reduce the maximum operating pressure per ASME B31G calculations, must be replaced with new pipe of similar specifications or if less than 6 ft in length, repaired with full sleeves. B31G calculations will be done by a qualified engineer or engineering firm. Alternatively, the operating pressure may be reduced, based on B31G calculations based on the actual remaining wall thickness and extent of the corrosion.</p> <p>If corrosion pitting is localized but exists to a degree that leakage might result, the pipe must be replaced or repaired.</p>
<p><b>Close Interval Survey</b></p>	<p>Company's Cathodic Protection Technicians will identify areas where a close interval survey is warranted according to the criteria presented in NACE 01-69, paragraph 10.1.1.3. Areas will include the possibility of stray currents, interference from foreign pipelines, low or variable protection levels. Due to the remote location of its pipelines, Company has experienced very stable and adequate CP levels. ILI inspection tool results have indicated few, if any, external coating failures or CP problems. Areas of high density of foreign lines, HCA's, rocky terrain, and older pipe will be considered for a CI survey.</p>

## 4.3

**Start-up  
Procedures**

Reference: 49 CFR Part  
195.402(c) (7), (8) & (9)

## 4.3.1

**SCADA  
Controlled  
Pipeline System****Control Center**

These procedures are general in nature.

The Control Center normally performs all start-ups. The following are the general principles that determine procedures for starting up a pipeline segment

Refer to the "*Pipeline Specific Supplement*" of this manual for individual Station Start-up Procedures.

1. Pipeline movements are based on the current schedule from the Pipeline System Scheduler
2. One hour prior to start-up of a line segment, the Control Center shall verify both the origination and destination are prepared for the scheduled pipeline movement.
3. The Pipeline Controller will review the appropriate control screens prior to start-up.
4. The pipeline Controller shall insure that all piping valves are aligned at every station for start-up.
5. The pipeline Controller shall verify the appropriate tank , booster, and manifold line-up at the origin station.
6. The pipeline Controller shall verify the destination is open and ready to receive the scheduled pipeline movement, and double check again the status of all mainline block valves (*should be opened*).
7. When all valves are aligned, the start-up is initiated by starting the origination booster pump.
8. Once the origination booster is started and sufficient pressure is available for proper operation of the mainline pump(s) at the origination station, the appropriate mainline unit(s) at the origin may be started. After the origination station is running, downstream pumping units may be started as required to achieve the required flow rate. Sufficient suction pressure should be available prior to each unit start, and no pump should throttle more than 50% of its differential pressure.
9. The Pipeline Controller shall monitor pressure and flow rates along the line segment until the system stabilizes. The line should become stable within 15 minutes of the last pumping unit start.

**Field Operations****Start up after maintenance**

If the line is shutdown for maintenance, emergency, or abnormal event situations, it is the responsibility of field personnel, prior to any attempts to restart the line, to assure that the line can be started up safely by verifying that:

- Manual valves have been opened or closed as is appropriate.
- Blowdowns, drains, or other valves open to sumps or atmosphere have been closed or opened as appropriate.
- Switch gear, safety devices, switches etc., are reactivated or “enabled”.
- All equipment required to make the line or facility functional has been replaced and is in working order.
- Air has been purged from the system when possible or that other considerations for its handling have been made.
- Local/remote switches have been switched to “remote” for start up.
- Communications have been re-established if they were out.
- Contact control center to start-up.

**“Local Control” Start Up of System**

If it becomes necessary to start the system manually under “local” controls, it is mandatory that each pump station to be operated and each terminal into which crude is delivered, be manned as long as the facility is operated under local controls.

**Note:**

See Pipeline Specific Supplement for individual station procedures.

**4.3.2*****Field Controlled  
Pipeline System***

The following are procedures for starting a Pipeline System that is not controlled by the Control Center.

1. Review the request for product movement and contact the Scheduler for any changes.
2. Notify parties in the system of the pending start-up. This will include time and date in which the start-up will occur.
3. Field operations personnel shall check the valve configurations from the pump discharge to the pipeline system inlet to assure all valves are open.
4. Field operations personnel then verify the discharge pressure control setpoint at the originating pump station.
5. Once the checks are completed, the pump(s) are started. After startup of the pump(s), the system is monitored closely until the system is stabilized.
6. The pipeline system is now in a start-up mode, fully pressurized, and flowing.
7. Flow rates and pressures are to be monitored closely for a reasonable time after the start-up to ensure a normal start-up operation.
8. Once the system is stabilized, Field operations personnel will monitor the system on a regular basis, observing system pressures and pump performance to assure a continuous and safe delivery of product into the hazardous liquid pipeline system.

## 4.4

**Shut Down  
Procedures**

Reference: 49 CFR  
Part 195.402(c)  
(7),(8)&(9)

## 4.4.1

**SCADA  
Controlled  
Pipeline System****Control Center**

The control center usually performs all normal shutdowns. The following are general principles that determine the procedures for shutting down the station:

**Refer to the "Pipeline Specific Supplement" of this manual for individual Station Shutdown Procedures.**

1. Notify Origination and Destination points one hour prior to the shutdown.
2. At the predetermined time or meter reading according to the pump schedule, shut down the mainline unit(s) beginning with the down stream pumps and working toward the origin. Also, shut down the origin booster. When the origin station is down continue to monitor line pressures, and close delivery valves as appropriate to maintain a line pack.
3. When the line is down, continue to monitor pressures on the static line.

**Field Operations****"Local Control" Shutdown of System**

If the entire line is to be shutdown in "local control"

- Each station being shutdown should be manned.
- A communications link should be established between all stations involved (via phone, cell phone or satellite phone)
- If practical, lines should be shutdown with sufficient pressure in the system (a) to minimize contamination or mixing at batch interfaces and (b) to reduce the possibility of volatiles in the crude or products vaporizing or going into the gaseous state. A pressure at which the line is to be shut in must be determined and communicated to all stations.
- When a planned, prolonged shutdown is to be made, it is generally desirable to shut the line down with positive pressure. Pumps should be shutdown beginning with the originating station and ending with destination station. Units are stopped at each station after a noticeable pressure drop has reached the station and the pumps have been allowed to pull for a short time on low suction.

**“Local Control” Shutdown of System** (continued)

- Once all mainline units have been stopped, system valves should be closed in the following order:
  - First incoming valves to terminals
  - Interior manifold valves at terminals
  - Mainline block valves.

This procedure should be completed to avoid allowing the pipeline to go “slack

**4.4.2****Field Controlled Pipeline System**

The following are procedures for shutting down a Pipeline System that is not controlled by the Control Center.

1. Review the request for product movement and contact the Scheduler for any changes.
2. Notify parties in the system of the pending shut down. This will include time and date in which the shut down will occur.
3. Field operations personnel will shut down mainline pumps and close pump discharge block valves. At the time designated for shutdown,
4. Field operations personnel will subsequently close downstream valves as appropriate.

**Note** Suitable documentation should be maintained for start-up time and periodic pumping unit status readings.

Coordination and communication with the input and disposition points, during shutdown or startup operations, must be maintained

**Section 7.0 - Emergency Procedures**

7.1

**General**  
Reference: 49 CFR  
Parts 195.50,  
402(c)(4), 402(e)

*An emergency condition is defined as any event that presents an immediate hazard to people or property.* Under such conditions, the affected part of the system shall not be operated until the unsafe condition has been corrected. Additional specific procedures are located in the *Company's Oil Spill Response Plan*.

All operating and maintenance personnel must be capable of recognizing and reporting any condition that is classified as an emergency on the pipeline. An emergency includes:

- a natural disaster affecting the pipeline;
- a failure in the pipeline causing any hazardous condition;
- a fire or explosion occurring near or directly involving the facility; or
- an accidental release of hazardous liquid from a pipeline facility.

7.2

**Response**

Typically Field Personnel and/or Pipeline Controllers are the first Company representatives to know of an emergency situation or condition affecting the pipeline facilities.

**First Responders**

As First Responders, Field Personnel are in the most logical position to respond to an emergency (fire, pipeline or equipment failure, natural disaster, civil disturbance, vandalism, etc.) and to prevent and/or reduce personal injury, property damage, and environmental harm.

The First Responder is the Company representative responsible to manage/ control the emergency until his facilitator or other emergency response personnel arrive on the scene. Immediate appropriate action may be of the utmost importance in mitigating the emergency.

**Responsibilities**

**SAFETY FIRST!** *The primary concern in any emergency situation is the safety of those directly involved and those who may become involved (i.e.- rescue personnel, general public, etc.).*

*Assess the situation.* The First Responder should not attempt rescue efforts, fight fires, or respond to an emergency beyond his/her capabilities. Assessment of the emergency situation is vital in determining to what extent emergency response should be carried out.

Refer to the *Oil Spill Response Plan* for specific procedures.

Names and Telephone Numbers of:

- Team Leaders
- Company maintenance and operating personnel
- Fire, law enforcement, ambulance, and Local Emergency Planning Committees (LEPC)
- Contractors to provide emergency services, equipment, and materials as needed

**NOTE:** The *Company's Oil Spill Response Plan* sets forth designated Company personnel responsible for contacting the proper public and/or governmental regulatory agencies.

***Vital Information  
required during  
Emergency***

The First Responder shall record as much of the available information upon first notification of an emergency without delaying any action to control the emergency. Any additional information can be recorded at a later time. A form similar to the Emergency Information Report shown in Figure 7.1-1 should be used. The information to be recorded:

- Determine if caller's safety is at risk. If so, instruct caller to move away from the emergency site and call back to relay further information. Once the caller's safety is assured, *additional information should include Name, telephone number, and exact location of caller. Collect any additional contact information to aid Company maintenance personnel in determining the emergency location site.*
- Type of emergency, such as: fire, line break or leak, natural disaster, vandalism, act of aggression, etc.
- Number of deaths or injuries and, if possible, potential for further danger to the public.
- Directions to the emergency site for response crews including location with reference to the State, county, city or town, Section, Township, Range, and identifiable landmarks such as, highways or railroads, waterways, or mile post numbers on the pipeline right of way.
- Type of surroundings, such as residential, industrial, or rural areas, and proximity to highways, railroads, power lines, rivers or streams, or other waterways or watersheds.

- Description of the commodity involved in the outage (odor, liquid or vapor,
- Time (including mm/dd/yy) the emergency was first discovered.
- Cause(s) of emergency, if known.
- Local weather conditions including wind velocity and direction, temperature, humidity, and cloud cover (particularly where highly volatile liquids are involved).
- Actions already taken for an emergency site such as, a list of the fire, law enforcement units, or other public or governmental agencies that have been notified.
- Any other essential data to determine additional response activities.

This Manual and the *Oil Spill Response Plan* set forth steps to be taken by the First Responder. However, no document can cover every emergency situation that may arise.

The actions described shall be applicable to the First Responder, depending on which one is available and in charge at the time.

*If these manuals do not address procedures for a particular emergency event, base decisions on best judgment and assume responsibility until further instructions are received from Company supervisory personnel*

**Field Operations Responsibilities**

The Pipeline Operator's response duties include:

- receiving, identifying and classifying notices of emergencies which:
  - ◆ need an immediate response by the Company, or
  - ◆ require a notice be given to fire, law enforcement, or other appropriate public or government agencies.

If a pipeline emergency occurs at a Company facility located within an area defined below, Pipeline personnel shall respond immediately to prevent hazards to the public.

- Four-lane highways
- Incorporated towns
- Subdivisions
- Other populated areas which are identified on official county maps.

**Control Center  
Responsibilities**

- Other populated areas which may not be identified on official count maps but whose location the Company has noted from ROW activities, pipeline surveys, or aerial photographs
- Navigable waterways, rivers and streams

Using the above criteria, areas along pipeline right-of-way and facilities have been identified as requiring **immediate response** in case of facility failure or malfunction.

**The prime responsibility of the Control Center is to prevent or minimize hazards to the public, by taking immediate and appropriate action including:**

- Ensuring the Caller's safety is not at risk, Notify the Field Superintendent and other appropriate company personnel of the emergency. They in turn will notify the proper regulatory agencies, initiate the *Pipeline Spill Response Plan*, and make personnel, equipment, instruments, tools, and materials available, as needed, at the scene.
- Maintain an accurate log of events as they occur.

As warranted, the Controller should immediately take whatever action is necessary to eliminate or control the emergency such as:

- Emergency shutdown of the pipeline system,
- Pressure reductions,
- Pumping of selected locations downstream from an emergency location,
- Diversion into tankage, and/or line valve closures, to minimize or stop discharge of hazardous material.

**Field  
Superintendent**

The Field Superintendent shall:

- Determine from the detecting employee the current status of the emergency.
- Take the necessary steps, or give appropriate orders, to isolate the affected area and shut down equipment feeding the area.
- Notify the CC for the pipeline system, if the detecting

**Pipeline  
Superintendent**

operational personnel, or others, had not already done so.

- Contact fire, law enforcement, and ambulance services as required. Coordinate with them, as applicable, using pre-planned and actual responses, including special precautions if a highly volatile liquid is involved.
- Contact fire, law enforcement, and ambulance services as required. Coordinate with them, as applicable, using pre-planned and actual responses, including special precautions if a highly volatile liquid is involved.
- Act as a central communications center for personnel at the emergency site.
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- Provide CC with the name of the affected pipeline system, your name and telephone number, location of incident and geographic directions on how to get to the emergency site. Emergency telephone numbers for the, law enforcement, fire departments, and other outside agencies can be found in the Pipeline Specific Supplement of this manual.

The Pipeline Superintendent shall:

- Arrange for any additional assistance needed to aid in cleanup and/or restoration of services.
- Arrange for appropriate documentation of the emergency event.
- Secure the area, if appropriate, by requesting local law enforcement agencies, and/or HAZMAT teams, to set up roadblocks, including any railroads and/or waterways.
- Conduct evacuation of the public, as necessary, to minimize public exposure.

## 7.3

**Reportable  
Emergency Event**  
*Reference: 49 CFR Part  
195.50*

The U.S. DOT requires an accident report for any failure of the pipeline in which a release of hazardous liquid results in any of the following:

- Explosion or fire not intentionally set by operational personnel.
- Loss of 5 or more barrels of hazardous liquid or carbon dioxide.
- Escape to the atmosphere of more than five barrels a day of highly volatile liquids.
- Death of any person.
- Bodily harm to any person resulting in the following
  - Loss of consciousness;
  - Necessity to carry the person from the scene;
  - Necessity for medical treatment.
  - Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.
- One or more of the following:
  - Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both exceeding \$50,000.
  - In the judgment of Area Management, was significant even though it did not meet the above-defined criteria for a reportable emergency event (accident).

*Form RSPA F 7000-1  
"Accident Report..."*

Management will also be responsible for the completion and transmittal of a written *Accident Report-Hazardous Liquid Pipeline Systems* (Form RSPA F 7000-1) as soon as practicable, but no later than 30 days after the discovery of the accident.

A written Accident Report must be submitted to the appropriate federal and state pipeline safety agencies as soon as practicable, but not later than 30 days after discovery of the emergency event (accident). Accident Reports shall be prepared on DOT Form 7000-1, or facsimile. Should operational personnel receive any changes in the information reported or additions to the original report on DOT Form 7000-1, area operational management shall file a supplemental report within 30 days.