DECEMBER 31, 2012

Mr. Eric J. Amundsen
Vice President and Chief Asset Integrity Officer
Panhandle Energy
5051 Westheimer Road
Houston, TX 77056

Re: CPF No. 3-2010-1006M

Dear Mr. Amundsen:

Enclosed please find the Order Directing Amendment issued in the above-referenced case. It makes a finding of inadequate procedures, withdraws one allegation, and requires that Panhandle Energy amend certain operating and maintenance procedures. When the amendment of procedures has been completed, as determined by the Director, Central Region, this enforcement action will be closed. Service of the Order Directing Amendment by certified mail is effective upon the date of mailing as provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Stephen M. Moore, Associate General Counsel, Panhandle Energy
5051 Westheimer Rd, Houston, TX 77056
Mr. David Barrett, Director, Central Region, OPS
Mr. Alan Mayberry, Deputy Associate Administrator for Field Operations, OPS

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
Panhandle Energy, a division of Southern Union Company,	)	**CPF No. 3-2010-1006M**
Respondent.	)	

ORDER DIRECTING AMENDMENT

On May 17–21, 2010, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an inspection of the written operations and maintenance procedures of Panhandle Energy (PE or Respondent) in Houston, Texas. PE is a division of Southern Union Company, which owns and operates more than 15,000 miles of pipeline that transport natural gas in the South and Midwest.[1]

As a result of the inspection, the Director, Central Region, OPS (Director), issued a Notice of Amendment (Notice) to Respondent dated December 21, 2010. In accordance with 49 C.F.R. § 190.237, the Notice alleged 20 procedures were inadequate to assure safe operations and proposed that the procedures be amended to address the alleged inadequacies.

PE responded to the Notice by letters dated January 21 and February 11, 2011. PE initially contested only four of the allegations, requested a hearing on those items, and submitted amended procedures for the remaining items. Both parties submitted pre-hearing materials on November 4, 2011. On November 8, 2011, the Director communicated by email that he accepted PE's amendments for 10 of the 20 items, but did not accept them to address the remaining items for various reasons. Respondent contested the remaining items in additional pre-hearing materials dated January 31, 2012, confirmed its intent to discuss them at the hearing, and provided additional explanations and further amendments.

In accordance with § 190.211, a hearing was held on February 16, 2012, in Kansas City, Missouri before the Presiding Official from the Office of Chief Counsel, PHMSA. At the hearing, both parties stipulated that based on the additional amendments submitted by PE, the

[1] http://www.panhandleenergy.com/comp_overview.asp (accessed Dec. 12, 2012). *See also* SEC Form 10-K, Southern Union Company at 3-5 (Feb. 2012). Panhandle Energy includes its subsidiaries Panhandle Eastern Pipe Line, Trunkline Gas, Trunkline LNG, Sea Robin Pipeline, and Florida Gas Transmission.

company had satisfied 13 of the 20 items. The remaining allegations in Items 1, 5, 7, 10, 15, 19, and 20 were discussed at the hearing.

After the hearing, Respondent submitted post-hearing materials dated April 16 and 22, 2012. Respondent stated that the parties had resolved several additional items, leaving only Items 10 and 19 contested and unresolved. Pursuant to § 190.213(b)(4), the Director submitted a post-hearing recommendation concurring that only Items 10 and 19 remained contested and unresolved.

Uncontested/Resolved Items

Respondent has submitted amended procedures to address the inadequacies alleged in Items 1-9, 11-18, and 20 of the Notice. The alleged inadequacies were as follows:

> 49 C.F.R. §§ 192.13(c) and 192.503(a) (**Item 1**) – PE's procedures for substantiating the maximum allowable operating pressure (MAOP) of new pipe did not specify the amount of new "pre-tested" pipe that is allowed to be installed during a maintenance project and did not specify the amount that would require a post-construction hydrostatic test.
>
> 49 C.F.R. § 192.225(b) (**Item 2**) – PE's welding procedures did not require the company to retain records of qualifying tests.
>
> 49 C.F.R. § 192.231 (**Item 3**) – PE's welding procedures did not define adverse weather conditions that would require protection to ensure welding quality is not impaired.
>
> 49 C.F.R. § 192.241(a) (**Item 4**) – PE's procedures for the inspection of welds did not require its inspectors to be qualified to conduct visual weld inspections.
>
> 49 C.F.R. § 192.241(b)(2) (**Item 5**) – PE's procedures for the inspection of welds did not define the number of welds that make nondestructive testing "impractical."
>
> 49 C.F.R. § 192.245(a) (**Item 6**) – PE's procedures for the repair and removal of weld defects did not reference the correct sections of API Standard 1104 (incorporated by reference, *see* § 192.7) for repairing and removing a weld that is unacceptable under § 192.241(c).
>
> 49 C.F.R. §§ 192.605(b)(1) and 192.612(b) (**Item 7**) – PE's procedures for assessing the risk of pipelines in the Gulf of Mexico and its inlets did not contain sufficient criteria and guidance to ensure consistent application.
>
> 49 C.F.R. §§ 192.605(b)(1) and 192.612(c)(2) (**Item 8**) – PE's procedures for underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets did not adequately describe the marking that is required when the operator discovers a pipeline has become exposed or poses a hazard to navigation.

49 C.F.R. §§ 192.605(b)(1) and 192.612(c)(3) (**Item 9**) **–** PE's procedures for underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets did not require the operator to bury an underwater pipeline that becomes exposed or poses a hazard to navigation.

49 C.F.R. §§ 192.605(b)(1) and 192.707(d)(2) (**Item 11**) **–** PE's procedures for placing and maintaining line markers did not require markers to have a current telephone number where the operator can be reached at all times; rather, the procedures permitted markers to list a collect call number that is no longer available.

49 C.F.R. §§ 192.605(b)(1) and 192.727(d) (**Item 12**) **–** PE's procedures for discontinuing service to a customer did not require the operator to utilize one of the three methods in the regulation to prevent the flow of gas.

49 C.F.R. §§ 192.605(b)(1) and 192.727(g) (**Item 13**) **–** PE's procedures for the abandonment of facilities did not require a report to be filed with PHMSA for each abandoned offshore pipeline or onshore pipeline facility that crosses a commercially navigable waterway.

49 C.F.R. §§ 192.605(b)(1) and 192.735(a) (**Item 14**) **–** PE's procedures for compressor stations did not identify combustible materials that must be stored a safe distance from the compressor building and did not specify the quantity of combustible materials that may be required for everyday use.

49 C.F.R. §§ 192.605(b)(1) and 192.739(a) (**Item 15**) **–** PE's procedures for inspecting and testing pressure limiting and regulating stations did not require fuel gas regulators ("Category 2" regulators) to be inspected and tested annually.

49 C.F.R. §§ 192.605(b)(1) and 192.739(a)(4) (**Item 16**) **–** PE's procedures for inspecting and testing pressure limiting and regulating stations did not require pressure control devices to be inspected to ensure they are properly protected from dirt, liquids, and other conditions that may prevent proper operation.

49 C.F.R. §§ 192.605(b)(1) and 192.751(a) (**Item 17**) **–** PE's procedures for preventing accidental ignition did not require the removal of certain potential ignition sources, such as cell phones, in areas where a hazardous amount of gas is being vented into open air.

49 C.F.R. §§ 192.605(b)(2) and 192.453 (**Item 18**) **–** PE's corrosion control procedures, including those for the design, installation, operation, and maintenance of cathodic protection systems, did not require the procedures to be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

49 C.F.R. § 192.605(b)(8) (**Item 20**) **–** PE's procedures for maintenance and normal operations did not contain detailed provisions requiring periodic review of the work done by employees to determine the effectiveness and adequacy of the procedures.

After reviewing the materials presented in writing and at the hearing, I find that Respondent's procedures were inadequate as alleged in the Notice, but that Respondent has successfully amended its procedures to address the inadequacies. Accordingly, Items 1-9, 11-18, and 20 of the Notice have been satisfied and Respondent is not ordered to take any further action with regard to those Items.

Contested/Unresolved Items

In its written submissions and at the hearing, Respondent contested the inadequacy of its procedures as alleged in Items 10 and 19 of the Notice. The alleged inadequacies are as follows:

Item 10: The Notice alleged that Respondent's procedures are inadequate with regard to § 192.625(b), which states:

> **§ 192.625 Odorization of gas.**
>
> (a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.
>
> (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:
>
> (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
>
> (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;
>
> (i) An underground storage field; (ii) A gas processing plant; (iii) A gas dehydration plant; or (iv) An industrial plant using gas in a process where the presence of an odorant:
>
> (A) Makes the end product unfit for the purpose for which it is intended;
>
> (B) Reduces the activity of a catalyst; or
>
> (C) Reduces the percentage completion of a chemical reaction;
>
> (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or
>
> (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

The Notice alleged that PE's procedures are inadequate because they do not include provisions for determining when transmission pipelines, including laterals, that are partially in a Class 3 or Class 4 location are required to be odorized.

In its written submissions and at the hearing, PE explained that its procedures contain provisions for determining when odorization is required, in particular Standard Operating Procedure B.12, *Evaluating Class Location Changes*, in Step 3 of Section 7.3, "Determine Subsequent Actions."

Respondent also noted that Step 7 requires the identification of Class 3 or Class 4 areas that require odorization and the procedure includes language from the regulation to guide that identification process. To clarify its procedures, PE added Appendix D to Procedure B.12 consisting of guidance that repeats the exceptions in § 192.625(b). Respondent also amended its procedures to make clear that it uses an electronic system for evaluating Class location and that personnel must look at the records to identify Class location and pipeline lengths.[2] Respondent explained that the amended procedures require the operator to calculate the percentage of pipe that is in a Class 3 or Class 4 area and then use the criteria in the regulation to evaluate whether odorization is required.

At the hearing, OPS alleged that PE's amended procedures were still inadequate because they do not describe how PE evaluates its pipelines to determine whether the lines need to be odorized. OPS suggested that PE should amend its procedures to be consistent with a 2009 final order issued by PHMSA.[3] The Presiding Official asked whether the alleged procedural inadequacy concerned the manner in which PE determined class location, the manner in which PE calculated the length of lateral lines, or some other issue. OPS responded that the issue was not how PE determined class location, but OPS did not further explain the inadequacy other than to restate that details were missing concerning how PE evaluates lateral lines to determine whether they need to be odorized.[4]

In its post-hearing submission, PE claimed that after communicating further with OPS, the company understood the disagreement concerns how the company defines a lateral line for purposes of determining whether at least 50 percent of a lateral is located in a Class 1 or Class 2 area under § 192.625(b)(3). In this regard, Respondent explained how its procedures designate the length of a lateral line and contested the manner in which OPS sought to apply the 2009 final order to PE's procedures.

Normally, gas in a transmission line in a Class 3 or Class 4 location must be odorized pursuant to § 192.625(b). In the case of a lateral transmission line which transports gas to a distribution center, § 192.625(b)(3) provides that odorization is not required if at least 50 percent of "the length of that line" is in a Class 1 or Class 2 location.[5] For an operator to determine whether a lateral meets this exception, the operator must calculate the length of the lateral and determine if 50 percent or more of the length is in a Class 1 or Class 2 location.

The 2009 final order issued in *ANR Pipeline* evaluated an operator's method for calculating the length of its laterals for purposes of applying the exception. ANR's pipeline system consisted of an interstate gas transmission line and a subsidiary pipeline system, or lateral system, that branched away from the interstate line at a single departure point. The lateral system delivered

---

[2] PE's Response at 4 and Exhibit Item 10 (Jan. 21, 2011).

[3] *See ANR Pipeline Co.*, CPF No. 3-2007-1006, 2009 WL 5538653 (Dec. 4, 2009). Final orders are also available at http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html; click "Enforcement Actions."

[4] Hearing transcript at 41-44.

[5] The intent of this exception was to exclude short segments of pipeline in predominantly rural areas where the likelihood of someone detecting a leak of odorized gas was lower. Odorization of Gas in Transmission Lines, 40 Fed. Reg. 20,279, 20,281 (May 9, 1975).

gas through a web of transmission lines, some branching off from others, all leading to different distribution centers. The source of gas at each end point on the lateral system could be traced back through commonly-shared branches to the single departure point on the interstate transmission line.

ANR calculated the length of each lateral line from its end point at the distribution facility all the way back to the single departure point on the interstate transmission line. As a result, the same upstream mileage shared by multiple lateral lines was factored into the length of each lateral.[6] PHMSA concluded this methodology was not allowed because it "overweighted" mileage in Class 1 and Class 2 locations, skewing the results in favor of finding each lateral had more than 50 percent of its length in a Class 1 or Class 2 location and artificially inflating the number of lines meeting the exception in § 192.625(b)(3).

In the current proceeding, OPS has sought to apply the same rationale to PE's procedures. After reviewing Respondent's amended procedures, however, I find they do not present the same problem addressed in the *ANR Pipeline* case. There is no indication that PE's procedures permit calculating the length of individual lateral lines from their respective end points at a distribution facility back to their common point of origin, double counting upstream mileage. To the contrary, Respondent explained in its post-hearing submission, and demonstrated through the use of a diagram included in its amended procedures, that it calculates the length of each lateral line from its end point at a distribution facility to its connection with the first distinct upstream transmission line that serves as the source of gas for the lateral line (as established when the lateral was constructed).[7] Since PE's procedures do not employ the improper methodology that was found to be a violation in *ANR Pipeline*, I find the 2009 final order does not support finding PE's procedures are inadequate.

In its post-hearing submission, Respondent contested what it believed was a requirement set forth in the *ANR Pipeline* decision that operators must recalculate the length of a lateral line if a new pipeline is constructed from the lateral to another distribution center.[8] Respondent argued that recalculating the length of the original lateral from its distribution center to a new intersection would be burdensome for operators and unnecessary for safety if there has been no change to the class location of the original lateral.

The question of whether an operator must recalculate the length of a lateral as a result of new construction was not explored under the specific facts in *ANR Pipeline*. In addition, OPS has not alleged in the Notice or at the hearing that Respondent's procedures are inadequate with regard to this issue. Accordingly, it is not necessary to address this issue raised by Respondent.

PE also argued that it would be improper for PHMSA to interpret § 192.625(b)(3) in the current proceeding because there is a pending rulemaking that proposes to alter the regulation.[9]

---

[6] *ANR Pipeline* at 5-6.

[7] PE's Post-hearing Submission, Exhibit B (Apr. 16, 2012).

[8] PE's Post-hearing Submission at 3.

[9] *See* Miscellaneous Changes to Pipeline Safety Regulations, 76 Fed. Reg. 73,570, 73,574, 73,579 (proposed Nov. 29, 2011) (proposing to clarify § 192.625(b)(3) to avoid any inconsistent application).

Generally, administrative agencies are not precluded from announcing or refining a regulatory interpretation in an adjudicative proceeding. I find no reason to withhold rendering a decision regarding the regulation in effect at the time of the allegation.

Having reviewed the record, I find PE's amended procedures include provisions for determining when transmission pipelines, including laterals, that are partially in a Class 3 location are required to be odorized. There is insufficient evidence in the record to conclude that PE's amended procedures are inadequate to assure safe operation. Therefore, this item is withdrawn.

Item 19: The Notice also alleged that Respondent's procedures are inadequate with regard to § 192.463(a), which states:

> **§ 192.463 External corrosion control: Cathodic protection.**
> (a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

The Notice alleged that PE's procedures are inadequate because they do not properly consider voltage (IR) drop when measuring cathodic protection levels to ensure compliance with the applicable criteria contained in Appendix D of Part 192. Specifically, the Notice alleged that when PE obtains readings that demonstrate there is inadequate cathodic protection after accounting for IR drop, such as data from instant-off readings, Respondent's procedures do not require the company to remediate the deficiency or verify that another criterion has been met.

At the hearing, OPS explained that Respondent uses the -850 mV criterion for determining if cathodic protection is adequate. The criterion requires operators to consider IR drop for valid application. OPS produced records from a close interval survey PE performed in 2009 showing locations on the pipeline where instant-off readings were less negative than -850 mV. OPS explained that using instant-off is the best method for considering IR drop, and that if cathodic protection levels are less negative than -850 mV when IR drop is considered, the applicable criterion has not been met. OPS alleged that PE's procedures are inadequate because they do not require the operator to take corrective action to remediate the low levels, or to meet one of the other criteria.

At the hearing and in its written submissions, PE contested the allegation that its procedures are inadequate. PE contested OPS's assertion that levels of cathodic protection are inadequate if the instant-off reading is less negative than -850 mV. PE also contested the assertion that instant-off readings are the best estimate available for considering IR drop. PE explained that Standard Operating Procedure D.22, *Application of Cathodic Protection Criteria*, addresses the applicable regulatory requirements. In accordance with those procedures, PE noted that it properly addressed the 2009 survey readings and that more recent survey results from 2011 indicate cathodic protection levels are as required.

Background

Operators are required to have written procedures for cathodic protection systems to protect their metallic pipelines from external corrosion.[10] A cathodic protection system with an impressed current prevents external corrosion on buried pipelines by applying a direct electric current to the metal of the pipeline in an amount sufficient to prevent the loss of metal from the pipeline to the surrounding environment.[11] If insufficient current is provided, corrosion can result.

Section 192.463 requires operators to use certain reference criteria for measuring the flow of electric current to or from their pipelines (pipe-to-soil potential) to determine if cathodic protection is adequate. One of the criteria PE uses is the -850 mV criterion described in Appendix D of Part 192, section I, paragraph (A)(1): "A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix." This is commonly known as the -850 mV current applied or "on" criterion.

To accurately determine if the pipe-to-soil potential meets this criterion, operators must consider the IR drop. IR drop is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth caused by the electrical resistance of the soil in which the pipeline is buried. Section II of Appendix D states: "Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement." If IR drop is not properly considered, cathodic protection may appear to meet the -850 mV criterion when, in fact, it does not.

Although Appendix D of Part 192 does not explicitly define how IR drop "must be considered," Respondent noted that section 6.2.2.1.1 of National Association of Corrosion Engineers (NACE) Standard SP-0169 (2007) states that "consideration [of IR drop] is understood to mean the application of sound engineering practice in determining the significance of voltage drops by methods such as: [1] measuring or calculating the voltage drop(s); [2] reviewing the historical performance of the CP system; [3] evaluating the physical and electrical characteristics of the pipe and its environment; and [4] determining whether or not there is physical evidence of corrosion." Part 192 does not incorporate NACE Standard SP-0169 by reference, but the criteria in Appendix D were based on and were substantially the same as those in the 1969 issue of that NACE standard.[12]

Using Data from Instant-Off Readings to Consider IR Drop

One method of considering IR drop is to measure or calculate the IR drop by interrupting the current and taking an instant-off reading. IR drop can be "minimized or eliminated by interrupting all of the direct current sources of the CP system and measuring the instantaneous

---

[10] §§ 192.605(b)(2), 195.402(c)(3).

[11] *Kinder Morgan Energy Partners, L.P.*, CPF No. 4-2006-5023, at 6-7, 2010 WL 6531634 (Aug. 31, 2010).

[12] Requirements for Corrosion Control, 36 Fed. Reg. 12,297, 12,299, 12,301 (Jun. 30, 1971). Cathodic protection regulations for hazardous liquid pipelines do incorporate NACE Standard SP-0169 (2007) by reference. *See* §§ 195.3, 195.571.

off-potential . . . . The difference between the on- and the off-potential indicates the magnitude of the IR voltage drop error when the measurement is made with the protective current applied."[13]

At the hearing, OPS contended that instant-off readings of less than -850mV on Respondent's pipeline indicated inadequate cathodic protection. In response, PE argued that the readings did not indicate inadequate cathodic protection because the "on" reading was -850 mV or more.

Although not cited by either party, for consistency I must consider prior PHMSA enforcement decisions that evaluated this issue. In 2010, PHMSA found a pipeline operator had failed to properly consider IR drop based on evidence of survey readings showing instant-off potentials that did not meet the -850 mV criterion.[14] In another case issued the same year, PHMSA stated that the use of close interval surveys and instant-off readings "means that readings with the current applied must be at least as negative as -850 mV plus the negative of the IR drop determined for each particular location."[15] Even as early as 1996, the agency issued a letter of concern explaining that "when the pipe-to-soil potential measured directly over the pipe is -850 mV, the IR drop must be zero or the protective potential on the pipe will be less than -850 mV."[16] The agency stated that unless the operator can demonstrate IR drop is zero or insignificant, "the required level of protection is not achieved." In 1998, PHMSA warned that instant-off readings of -852mV "barely meet" the -850 mV criterion.[17]

PHMSA's enforcement history indicates it is the agency's position that cathodic protection is inadequate if the instant-off reading from an interrupted current is less negative than -850 mV.

PE argued that operators are not even required to take instant-off readings for several reasons. First, PE argued that the regulations do not require instant-off. Second, PE argued that interpretations issued by PHMSA state that instant-off is not required. Finally, PE argued there is no technical support for finding instant-off is the best or even the preferred method for considering IR drop.

With regard to PE's position that the regulations do not require instant-off, PE argued that taking "on" and instant-off readings are actually two separate criteria and that under the regulations, operators need only meet one of the criteria in Appendix D of Part 192.

PE's position that operators need only meet one of the criteria in Appendix D is supported by § 192.463, which states that cathodic protection systems must provide a level of cathodic protection "that complies with *one or more* of the applicable criteria." (emphasis added.) This position also is reflected in a 1992 interpretation cited by Respondent, which stated that "no

---

[13] A. W. Peabody, Peabody's Control of Pipeline Corrosion at 50-51 (2d ed. 2001), included in OPS's Pre-hearing Submission.

[14] *BP Pipelines (North America), Inc.*, CPF No. 4-2007-5003, at 3-5, 2010 WL 6518288 (Jul. 19, 2010).

[15] *Sunoco Pipeline, L.P.*, CPF No. 4-2007-5040, at 10, 2010 WL 5761108 (Dec. 16, 2010).

[16] *Texas-New Mexico Pipeline Co.*, CPF No. 4-1996-5018-C (formerly 46518C), 1996 WL 34390103 (Dec. 24, 1996).

[17] *Trans Mountain Oil Pipeline Corp.*, CPF No. 5-1998-5009-W (formerly 58509W), at 2-3, 1998 WL 35166459 (May 5, 1998).

further test data are required if one of the criteria is met."[18] Appendix D of Part 192 does not explicitly list instant-off or any other specific methods for considering IR drop.

Although operators need only meet one of the criteria, I reject Respondent's suggestion that taking "on" and instant-off readings necessarily represent two completely separate criteria. Data from both readings can be used to determine compliance with one criterion: the -850 mV "on" criterion. That is because the -850 mV criterion requires operators to consider IR drop for valid interpretation of the voltage measurement with the current applied. Instant-off readings are taken by pipeline operators for the purpose of considering IR drop.[19]

With regard to PE's position that agency interpretations demonstrate instant-off is not required, Respondent cited two interpretations. The first interpretation, from 1985, described a (then) new enforcement policy that OPS would accept an operator's consideration of IR drop, even if the operator had not taken instant-off readings.[20] One exception, OPS explained, was if a corrosion leak had occurred, at which point the operator "must measure the level of cathodic protection (polarized potential) at the soil to metallic structure interface." If the level of cathodic protection after measuring IR drop "is less than that required by the regulations," the agency could take enforcement for failing to properly considered IR drop. A second interpretation letter, issued in 1991, repeated this enforcement policy.[21]

I agree the interpretation letters do not suggest that operators are always required to use instant-off to consider IR drop. The interpretations do confirm that operators must be able to demonstrate the adequacy of corrosion protection and how the operator considers IR drop, and that operators may be subject to enforcement action if they do not properly consider IR drop.[22]

With regard to PE's position that instant-off is not the best method or even the preferred method for considering IR drop, I agree there is not sufficient evidence in the record of this case to prove that instant-off is the "best" method to consider IR drop. With regard to whether instant-off is preferred by PHMSA, however, I must consider PHMSA's enforcement history to the extent the agency has taken a position on the issue.

In a 2009 decision, PHMSA found a violation when the operator had not conducted interrupted surveys on its entire system.[23] In that case, the operator claimed it had used other methods to consider IR drop, such as visual observation and measurement of pipe wall thickness, in-line

---

[18] PHMSA Interpretation #PI-92-062 issued to Mr. Dan H. Weaklend (Nov. 23, 1992). PHMSA interpretations are available at http://www.phmsa.dot.gov/pipeline/regs/interps.

[19] PE argued that instant-off readings can also be used separately for the -850 mV "polarized" criterion listed in 6.2.2.1.2 of NACE Standard SP-0169. Since Appendix D of Part 192 does not list that criterion, PE argued that PHMSA cannot require its use. Notwithstanding PE's assertion, however, PHMSA recognizes the appropriate use of instant-off readings to consider IR drop when using the -850 mV "on" criterion.

[20] PHMSA Interpretation #PI-85-001 issued to Mr. Lawrence Ogden (Mar. 18, 1985).

[21] PHMSA Interpretation #PI-91-025 issued to Mr. Dan H. Weaklend (Aug. 29, 1991).

[22] Notwithstanding the enforcement policy from the mid-1980s, PHMSA may always verify compliance with the requirement in the regulation to properly consider IR drop, even absent a corrosion leak.

[23] *Enterprise Products Operating, LLC*, CPF No. 4-2007-5015, at 4-7, 2009 WL 5538652 (Dec. 2, 2009).

inspection (ILI), and leak history. PHMSA found these other methods were either undocumented or did not produce relevant data to support a determination as to the adequacy of cathodic protection. In particular, PHMSA noted the operator had not submitted "any other documentation, such as reports or summaries, that document the use of all these methods in a manner that would enable Respondent to determine whether its cathodic protection systems complied with applicable standards."

In another case, PHMSA found that even though the operator's procedures included methods for considering IR drop identical to the NACE standard, the operator had failed to use an interrupted survey or document the use of another acceptable method to consider the significance of IR drop on the entire pipeline.[24] In 2010, PHMSA found that reviewing the historical performance of the cathodic protection system and the absence of reportable spills caused by corrosion did not demonstrate proper consideration of IR drop.[25] Even as early as 1997, PHMSA warned that an operator was not properly considering IR drop, because it was not taking instant-off readings or performing some other test.[26] In 1998, PHMSA issued a letter of concern stating that "Instant Off is the preferred method for obtaining IR Drop free readings."[27]

The agency's enforcement history over many years demonstrates that PHMSA considers instant-off readings to be the preferred method of considering IR drop because that method provides probative data as to the amount of the IR drop at any given location on the pipeline. Other evaluation methods have not been found to be acceptable on their own, at least based on the specific facts presented in those cases. While the prior enforcement decisions do not foreclose the use of other methods of considering IR drop, they do show that other such methods must be documented and must produce relevant data to support a determination about the present level of cathodic protection on the pipe.

Evaluation of Respondent's Procedures

In its written submissions and at the hearing, PE contended that its procedures address the applicable regulatory requirements and industry best practices. In particular, PE explained that Procedure D.22 allows the "identical" use of the four options listed in section 6.2.2.1.1 of NACE Standard SP-0169.[28] Respondent also contended that its procedures are technically superior to those proposed by OPS because they provide for consideration of all factors related to the pipe segment, allow the use of (but do not require) instant-off to measure IR drop, and recognize that pipe-to-soil potentials contain error due to IR drop.

Having reviewed Respondent's procedures, I find that PE uses the -850 mV criterion to determine the adequacy of its cathodic protection systems. Using this criterion, PE must

---

[24] *Marathon Ashland Pipe Line, LLC*, CPF No. 5-2003-5013, at 1-3, 2006 WL 3825308 (Feb. 16, 2006).

[25] *BP Pipelines (North America), Inc.*, CPF No. 4-2007-5003, at 4-5, 2010 WL 6518288 (Jul. 19, 2010).

[26] *Plantation Pipeline Co.*, CPF No. 2-1997-0509 (formerly 27509W), at 2, 1997 WL 34614818 (Dec. 8, 1997).

[27] *Williams Gas Pipeline – Central*, CPF No. 5-1998-0020-C (formerly 58020C), at 3, 1998 WL 35166444 (Oct. 21, 1998).

[28] PE's Post-hearing Submission 5.

consider IR drop to obtain an accurate reading of the pipe-to-soil potential. Section 7.3 of PE's Procedure D.22 permits the use of close interval surveys and instant-off readings, which PHMSA recognizes as the preferable method to consider IR drop.[29] PE's procedures also permit considering IR drop by comparing historical levels of cathodic protection with physical evidence from the pipeline "to determine whether corrosion has occurred." PE may compare soil corrosiveness with physical evidence "to determine whether corrosion has occurred." Finally, PE may obtain physical evidence of corrosion from leak history, pipe inspection reports, and ILI data.

With regard to the use of interrupted surveys, PHMSA considers cathodic protection inadequate at a given location if the instant-off reading from an interrupted current is less negative than -850 mV. At many locations on Respondent's pipeline in 2009, the instant-off readings demonstrate that cathodic protection was less negative than the -850 mV standard. Although PE's procedures recognize that pipe-to-soil potentials contain error due to IR drop, the procedures only require adjustment of the pipe-to-soil potentials to account for IR drop when operational or historic data indicates there is "ongoing corrosion activity."[30] Because Respondent's procedures do not recognize that instant-off survey readings of less than -850mV require additional protection (or compliance with another criterion), I find the procedures are inadequate.

Other Issues Raised by Respondent

PE suggested that if operators were required to consider IR drop by taking instant-off readings, they "would no longer be allowed" to use other methods for considering IR drop, resulting in technically unsound and potentially erroneous determinations of effective corrosion control.[31]

I find this argument implausible, since operators using instant-off readings to consider IR drop may still use other methods, so long as the methods are documented in the operators' procedures in a manner that demonstrates the methods result in data relevant to considering IR drop and the level of cathodic protection on the pipe. For example, a documented review of leak history can show where a pipeline has not received adequate protection.

PE also argued that the Notice and related testimony indicate the company's procedures for considering IR drop are adequate "except when instant-off data is collected."[32]

At the hearing, however, OPS stated that PE should not infer there were no other issues.[33] I find the allegations of inadequate procedures in the Notice do not imply PE's procedures are otherwise adequate.

---

[29] PE's Pre-hearing Submission, Exhibit 19-A-3 (Nov. 4, 2011).

[30] The methods included in the NACE standard are written

[31] PE's Post-hearing Submission at 7-8.

[32] PE's Post-hearing Submission at 7.

[33] Hearing transcript at 57.

PE further argued that instant-off readings are not always collected on its system. For example, a significant percentage of PE's system mileage uses direct weld galvanic anodes for cathodic protection and it is not possible to perform current interruption on such systems.

PHMSA recognizes interrupted surveys may not be feasible for certain cathodic protection systems. The regulations still require that IR drop be considered when using the -850 mV criterion on sacrificial anode protected systems. As noted in the 1991 interpretation letter, "[i]t is possible to consider the IR drop on magnesium anode protected systems." When considering IR drop on a system using galvanic anodes, PHMSA has previously required the operator to use documented methods that "account for differences in environmental and soil conditions, and the resulting differences in IR drop, that could occur" throughout the system.[34]

PE further explained that it responded appropriately and in accordance with its procedures to the survey readings performed in 2009. Respondent noted that it had identified other areas for remedial action using the operator's procedures. PE's analysis involved integration of close interval survey readings and ILI data, with excavation and direct examination performed for further analysis. Following recoat and backfill of excavated areas, PE took additional readings to verify restoration of cathodic protection. PE contended that it conducted another close interval survey in 2011, which indicated that all low potentials from 2009 had been successfully remediated and there were no longer any instant-off potentials less negative than -850 mV.

PHMSA recognizes PE's commitment to ensuring adequate cathodic protection in light of the corrective action it has described. For the purpose of this enforcement proceeding, the corrective action does not rebut the finding of inadequate procedures.

For the above reasons, PE's procedures are inadequate to assure safe operations. 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 written operations and maintenance procedures:

1. PE must revise its procedures for using the -850 mV criterion to require that where instant-off readings are less than -850 mV, PE must remediate the level of protection or verify that another of the criteria in Appendix D is satisfied. PE's procedures may permit the use of methods for considering IR drop other than instant-off, if such methods are appropriately documented to demonstrate they produce data that support a justifiable determination about the IR drop and existing level of cathodic protection on the pipeline.

2. Within 45 days following receipt of this Order, PE must submit procedures that have been revised pursuant to Item 1, above. All documentation demonstrating compliance with the Order must be submitted to David Barrett, Director, Central Region, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 901 Locust Street, Suite 462, Kansas City, MO 64106-2641.

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

---

[34] *Kinder Morgan Energy Partners, L.P.*, CPF No. 4-2006-5023, at 10, 2010 WL 6531634 (Aug. 31, 2010).

Failure to comply with this Order may result in the administrative assessment of civil penalties not to exceed $200,000 for each violation for each day the violation continues and/or referral to the Attorney General for appropriate relief in a district court of the United States.

______________________________ _________________________

Jeffrey D. Wiese Date Issued
Associate Administrator
for Pipeline Safety