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April 14, 2017

RECEIVED

APR 14 2017

PUBLIC SERVICE
COMMISSION

Via Hand-Delivery

Ms. Talina Mathews, Ph.D.
Executive Director
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

Re: In the Matter of: The Application of Apache Gas Transmission Company, inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, Approval of Financing Pursuant to KRS 278.300 and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc., for Approval of a Gas Pipeline Replacement Surcharge and Tariff - Case No. 2017-00168

Dear Ms. Mathews:

Enclosed please find for filing with the Commission in the above-referenced case an original and ten (10) copies of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc.'s Application in the above-styled case.

Please do not hesitate to contact me if you have any questions.

Sincerely,

L Allyson Honaker

L. Allyson Honaker

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
APR 14 2017
PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Apache Gas Transmission Company, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, Approval of Financing Pursuant to KRS 278.300 and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc. for Approval a Gas Pipeline Replacement Surcharge and Tariff	)	Case No. 2017- 00168

VERIFIED APPLICATION

Now comes Apache Gas Transmission Company, Inc., ("Apache Gas" or the "Company"), pursuant to KRS 278.020, 278.300, 278.509, 807 KAR 5:001 Sections 14 and 15, and other applicable law, and hereby respectfully requests from the Kentucky Public Service Commission (Commission) an Order: 1) granting a Certificate of Public Convenience and Necessity (CPCN) for approval to: a) implement a pipeline replacement program ("PRP"); b) repair and replace existing natural gas pipelines; 2) approve financing of the proposed project; and 3) implement a gas pipeline replacement surcharge mechanism. In addition, Burkesville Gas Company, Inc., ("Burkesville Gas"), Apache Gas' only customer, is requesting to also implement a gas pipeline replacement surcharge mechanism to pass on any surcharge that is approved for Apache Gas, to Burkesville Gas' retail customers. In support of this Application, Apache Gas and Burkesville Gas respectfully state as follows:

INTRODUCTION

1. Pursuant to 807 KAR 5:001, Section 14(2), Apache Gas is a Kentucky corporation originally incorporated on April 17, 1997, in good standing, and a public utility as that term is defined in KRS 278.010(3), and, therefore, is subject to the Commission's jurisdiction. Apache Gas is engaged in the business of furnishing wholesale natural gas services to Burkesville Gas in Cumberland County, Kentucky.

2. Pursuant to 807 KAR 5:001, Section 14(2), Burkesville Gas is a Kentucky corporation originally incorporated on September 25, 1990, in good standing, and a public utility as that term is defined in KRS 278.010(3), and, therefore, is subject to the Commission's jurisdiction. Burkesville Gas is engaged in the business of furnishing natural gas services to customers in Cumberland County, Kentucky.

3. Apache Gas and Burkesville Gas' business address is 119 Upper River Street, Burkesville, Kentucky 42717.

4. The electronic mail address for Apache Gas is apachegastransmission@gmail.com.

5. The electronic mail address for Burkesville Gas is burkesvillegas@gmail.com.

6. Copies of all orders, pleadings and other communications related to this proceeding should be sent to:

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BACKGROUND

7. Maintaining the safety and reliability of the natural gas infrastructure is of utmost importance to Apache Gas and Burkesville Gas, their customers and communities, the Commission and federal regulators. In fact, maintaining safety and reliability of natural gas delivery systems prompted this Commission to approve Duke Energy Kentucky's Accelerated Main Replacement Program (AMRP).[1] Since then, several other natural gas utilities have also received approval from the Commission to implement AMRPs or PRPs.[2]

8. On July 1, 2013 Apache Gas met with Commission Staff to discuss four areas of pipeline which Apache Gas had discovered were in need of repair on Apache Gas' system. Commission Staff suggested that Apache Gas consider implementing a PRP program pursuant to KRS 278.509. Commission Staff also recommended that Apache Gas request a PSC Staff Opinion regarding Apache Gas' status as a utility and its ability to implement a PRP program pursuant to KRS 278.509.[3] The PSC subsequently conducted an inspection on Apache Gas' system and, in its 2014 Inspection Report, noted these four areas were in need of repair. Since that time, Apache Gas has repaired two of the four areas noted in the 2014 inspection, but the remaining two areas are more difficult and will

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[1] *In the Matter of an Adjustment of the Gas Rates of the Union Light, Heat and Power Company,* Case No. 2005-00042 (Ky. P.S.C. Order, December 22, 2005) and *In the Matter of an Adjustment of the Gas Rates of the Union Light, Heat and Power Company,* Case No. 2001-00092 (Ky. P.S.C. Order, January 31, 2002).

[2] *See, In the Matter of Application of Columbia Gas of Kentucky, Inc., for an Adjustment of Rates,* Case No. 2009-00141(Ky. P.S.C. Order, October 26, 2009); *In the Matter of Application of Atmos Energy Corporation for an Adjustment of Rates,* Case No. 2009-00354 (Ky. P.S.C. Order, May 28, 2010); *In the Matter of Application of Delta Natural Gas Company, Inc., for an Adjustment of Rates,* Case No. 2010-00116 (Ky. P.S.C. Order, October 21, 2010 and *In the Matter of Kentucky Frontier Gas, LLC for Approval of Consolidation of and Adjustment of Rates, Approval of AMR Equipment and a Certificate of Public Convenience and Necessity for Installation of AMR, Pipeline Replacement Program, Revision of Non-Recurring Fees and Revisions of Tariffs,* Case No. 2011-00443 (Ky. P.S.C. Order, April 30, 2013).

[3] A copy of Apache Gas' letter requesting a Staff Opinion is attached as Exhibit A and a copy of the PSC Staff Opinion is attached as Exhibit B.

be more expensive to replace. The two areas that were noted in the 2014 Inspection Report which have been repaired are Doug Lewis Section A and the Spoon Branch Section. Apache Gas also repaired the Doug Lewis Section C, which was an undersized 3" High Density Polyethylene ("HDPE") pipe, and caused flow restrictions. The Spoon Branch and Doug Lewis C sections were upgraded to 6" HDPE pipe from 3" HDPE pipe, which increased the system's total capacity. The two remaining sections that are in need of repair, as noted in the 2014 Inspection Report, are the Cliff Norris Section and the Doug Lewis Section B. Both of the remaining areas are located in more rural, difficult to access areas, contain more rock content, are on a steeper grade, and are, therefore, more costly to repair. Apache Gas is also proposing to repair the Allen Creek Road Drainage Ditch Section as a part of this PRP. The Allen Creek Road Drainage Ditch Section is currently 3 inch pipe which crosses a drainage area between two higher grades and has a high percentage of rock. Due to erosion, this section has become exposed. This approximately 100 foot section will be replaced with 6" HDPE pipe.

9. Apache Gas has identified a need to replace portions of natural gas pipeline infrastructure in order to increase safety, lower the risk for leakage, breakage, or damage, and increase the total system capacity.

10. The natural gas pipelines situated in the areas of concern for Apache Gas are comprised of HDPE, however, due to the location, rough terrain and steep grades, the pipeline is exposed and in need of replacement.

11. Through the PRP, Apache Gas proposes to address the three sections of pipeline known as the Cliff Norris and the Doug Lewis Section B, and Allen Creek Road Drainage Ditch. These sections are in difficult to access areas; however, the Cliff Norris

section is located in the worst terrain. The location of this section, rock content, and steep grade make it much more difficult and expensive to repair.

12. Historically, the Company has replaced or repaired pipelines after a failure or excavation damage has occurred, a practice that continues to this day. However, a more targeted and accelerated replacement schedule is necessary to effectively mitigate the associated risks of these three sections of pipeline, before a hazardous situation presents itself.

13. Apache Gas is a small gas company with annual revenues of approximately $115,000. The PRP is needed to allow Apache Gas to fund the needed repairs, which will cost more than the annual revenues of Apache Gas.

THE PROPOSED PRP

14. Apache Gas proposes a natural gas pipeline replacement program and recovery mechanism, Rider PRP. This new service program identifies, addresses, and accelerates replacement of natural gas pipelines that are in need of repair or replacement. Under the PRP initiative, Apache Gas will repair or replace the exposed natural gas pipelines that have been in service for many years. Apache Gas and, ultimately, Burkesville Gas' customers, and the public at large, will benefit from the improved system capacity, and the enhancement of safety and reliability as a direct result of the PRP. Based on Apache Gas' small size, Apache Gas will need to obtain a loan to fund the PRP and use the surcharge amounts collected each month to repay the loan. Approval to obtain financing is also included in this Application. Apache Gas intends to file an annual report with the Commission to show the amount of PRP surcharge collected the previous year, the repayment amount on the loan and any additional projects that are projected to be

included in the PRP.

COMMISSION AUTHORITY TO APPROVE THE PRP

15. The Commission has authority to approve Apache Gas and Burkesville Gas' PRP initiative and cost recovery mechanism through express statutory authorization and also under its plenary rate-making authority.

16. KRS 278.509 explicitly authorizes the Commission to approve a gas pipeline replacement program and provide for the recovery of costs thereof that are not recovered in the existing rates of a regulated utility, providing that the Commission determines the costs of the program are fair, just, and reasonable.

17. Apache Gas' PRP initiative, constitutes a pipeline replacement program consistent with and authorized by KRS 278.509, which provides in relevant part:

> Notwithstanding any other provision of law to the contrary, upon application by a regulated utility, the commission may allow recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility. No recovery shall be allowed unless the costs shall have been deemed by the commission to be fair, just, and reasonable.[4]

18. The Kentucky Supreme Court has affirmed this Commission's authority to approve such a program and cost recovery methodology under its broad, plenary ratemaking authority, holding:

> We agree with the view that the PSC had the plenary authority to regulate and investigate utilities and to ensure that rates charged are fair, just, and reasonable under KRS 278.030 and KRS 278.040. This authority allowed the PSC to allow the rider and to re-calculate the dollar amount of the surcharge in expedited annual proceedings even before the effective date of KRS 278.509, which expressly clarified (but did not create) the PSC's authority to allow recovery of the cost of natural gas pipeline replacement not covered by existing rates so long as the rates are fair, just, and reasonable.[5]

[4] KRS 278.509.

19. Moreover, the Kentucky Supreme Court affirmed that the Commission can approve this type of mechanism outside of a general rate case.

> The plain language of KRS 278.190 does not actually require the PSC proceed with a general rate case or other particular process every time some new rate or change in rates is requested. To the contrary, the statute simply provides that upon filing of the schedule of new rates, the PSC "may" conduct a "hearing concerning the reasonableness of the new rates" on its own motion or if the complaint is filed by any person challenging the rates as unreasonable or otherwise contrary to the law under KRS 278. 260.[6]

20. Apache Gas and Burkesville Gas respectfully submit that its PRP initiative is a natural gas pipeline replacement program not covered by existing rates and the corresponding surcharge mechanism to recover costs under the program is fair, just, and reasonable.

<u>THE ATTRIBUTES OF THE PRP ARE JUST AND REASONABLE</u>

21. The proposed PRP would result in the replacement of approximately 1,800 feet of the Company's existing natural gas pipelines and would, thereby, minimize the potential for damages and leaks caused by natural forces and third-party excavation.

22. Apache Gas intends to issue the notice to proceed to each of its contractors simultaneously. However, one contractor required more notice to begin work than the other contractor, so work on the Cliff Norris section may commence sooner than the Doug Lewis B and the Allen Creek Road Drainage Ditch sections.

23. The PRP initiative will be coordinated by Apache Gas and Burkesville Gas personnel along with outside contractors. Any work that can be performed by in-house

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[5] *Kentucky Public Service Commission v. Commonwealth of Kentucky Ex. Rel. Jack Conway*, 324 S.W.3d 373, 383 (Ky. 2010).

[6] *Id.*, at 378.

personnel will be performed so as to keep the costs of the repairs and the PRP surcharge low for customers. Apache Gas has received estimates for the repairs of the pipelines in question; these estimates are attached as Exhibit C. Apache Gas and Burkesville Gas believe these repairs will improve system integrity, reduce overall program costs, and minimize disruption to, and outages for, customers.

24. The Company's PRP responds to the 2014 Commission Inspection Report that cited four areas in Apache Gas' system that needed repaired. Apache has addressed two of the four areas of concern, and has identified an additional area of concern, those of which were discussed in paragraph 8 above.

25. Apache Gas proposes that the PRP surcharge for the projects included in this Application be implemented over a period of fifteen years, beginning in May 2017, or as soon as financing is approved and closed. The Company projects the total cost to repair and replace the pipeline will be approximately $130,000. There should not be any added Operations and Maintenance ("O&M") expenditures under the PRP since this will be replacing existing pipeline.

REQUEST FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

26. Apache Gas is requesting a CPCN pursuant to KRS 278.020 and 807 KAR 5:001 Section 15 for its PRP initiative. Apache Gas proposes to implement the PRP for the reasons set forth above. Under the proposed PRP, Apache Gas will repair or replace the exposed natural gas pipelines.

27. The portions of the pipeline that will be repaired and replaced as a part of

this CPCN are the Cliff Norris Section, the Doug Lewis Section B, and the Allen Creek Road Drainage Ditch Section. The Cliff Norris Section currently consists of approximately 900 feet of 6 inch HDPE pipe. This section has the steepest grade, which has been estimated to be 30-35%. The Cliff Norris section goes up a hill on one side and down the hill on the other and has approximately ninety-five percent (95%) rock content. This section will be replaced with approximately 900 feet of 6 inch HDPE pipe. The Doug Lewis B Section currently consists of 3 inch HDPE pipe. The grade is much less than the Cliff Norris Section and is approximately 750 feet long. The rock content is also much less; with an estimated fifty percent (50%) being shale, which will be easier to cut through. Access to the Doug Lewis Section B is better than the Cliff Norris Section. The Doug Lewis Section B will be upgraded to 6" HDPE main to improve flow capabilities in this area and to stay consistent with Apache Gas' current practices of upgrading any 3" pipe remaining on its system with 6" pipe. This will also improve Apache Gas' total system capacity. The Allen Creek Road Drainage Ditch Section currently consists of 3" pipe that crosses a drainage area between two higher grade areas and the area has a high percentage of rock. This area would only have water during and following a rain which then drains into Allen Creek. The Allen Creek Road Drainage Ditch Section has become exposed due to erosion and should be replaced. This section is approximately 100 feet long and will be replaced with 6" HDPE pipe.

28. In accordance with 807 KAR 5:001 Section 15(2)(a), the Application and supporting testimony provides the evidence to show that the PRP is required by public convenience or necessity. The program will allow Apache Gas to continue to provide safe, reliable, and reasonably priced retail natural gas service to customers by replacing known

aging infrastructure that has become exposed. The 2014 Inspection Report also stated these areas were in need of replacement and/or repair.

28. In accordance with 807 KAR 5:001 Section 15(2)(b), regarding the filing of franchise agreements, Apache Gas states that it does not have any franchises. Burkesville Gas states that it has previously filed with the Commission the applicable franchises from the proper public authorities. Additionally, to the extent a local city or municipality requires the Company to obtain a construction permit, the Company will follow such local regulations and obtain any necessary local permits prior to beginning any work.

29. In accordance with 807 KAR 5:001 Section 15(2)(c), which requires the Company to provide a full description of the proposed location, route, or routes, including a description of the manner in which the facilities will be constructed, and Section 15(2)(d)(1) which requires maps to suitable scale showing the location or route as well as the location to like facilities owned by others, Apache Gas respectfully states that Exhibit D includes a map its facilities and the area that will be impacted by this project. Because the Company's PRP is applicable only in the area currently served by Apache Gas and Burkesville Gas, the program will not compete with any public utilities, corporations, or persons.

30. In accordance with 807 KAR 5:001 Section 15(2)(d)(2), requiring plans and specifications and drawings of the proposed plant, equipment, and facilities Apache Gas respectfully states that Exhibit E to this Application contains the work specifications for the natural gas pipeline replacements. These documents are being filed in both paper medium and pdf format on an electronic storage medium.

31. In accordance with 807 KAR 5:001 Section 15(2)(e), the Company states

that it will finance this new construction through a loan from either Lake Cumberland Area Development District or First and Farmers Bank, with repayment of the loan to be made through the proposed surcharge mechanism as authorized by KRS 278.509. Apache Gas has calculated the amount of the cost for the projects involved in the PRP and with a 15 year repayment term and a 2.8 % interest rate (which are the terms expected with the Lake Cumberland Area Development District loan), the annual PRP surcharge to Burkesville Gas will be approximately $10,740.[7] Burkesville Gas is also requesting to implement a PRP surcharge to pass through the PRP surcharge to its consumers. The annual PRP surcharge to each of Burkesville Gas' residential customers will be approximately $36.00 divided into equal monthly payments of $3.00. The annual PRP surcharge to Burkesville Gas' industrial customers will be approximately $42.00 divided into equal monthly payments of $3.50. Apache Gas will recalculate the surcharge amount on a yearly basis to true-up the collection as well as to add any additional pipeline replacements that may be needed in the future. Burkesville Gas will adjust its PRP surcharge according to Apache Gas' recalculations.

32. In accordance with 807 KAR 5:001 Section 15(2)(f), the Company states that in terms of Operations and Maintenance expense, there are no incremental operating costs associated with the PRP once the program is completed. Once installed, these new pipelines will simply be a replacement of the existing pipelines with similar Operations and Maintenance expenses as currently exists.

33. Since this case is not intended to add a new source of gas supply, but rather

[7] *See E*xhibit F for a complete breakdown of estimated costs of the projects, terms of the anticipated loan from the Lake Cumberland Area Development and the surcharge amounts to Burkesville Gas' customers by customer class.

to make certain that the gas the Company currently delivers is handled safely and economically, energy efficiency and DSM consideration are not applicable to this proceeding.

34. Apache Gas respectfully states that the PRP is needed to respond to an identified integrity risk to its natural gas delivery system that the Company must do to comply with state and federal regulations, not to mention to continue to provide safe and reliable service for the benefit of its natural gas customers. Moreover, the PRP will not result in a wasteful duplication of facilities. The PRP is intended to replace existing pipelines identified as presenting an integrity risk, so as to mitigate the conditions and risks set forth above.

REQUEST TO ISSUE EVIDENCE OF INDEBTEDNESS

35. Pursuant to 807 KAR 5:001 Section 12(2)(a)-(i), Apache Gas is filing the following information in Exhibit G, which is incorporated herein and made a part of this Application:

Exhibit # Page	Description	807 KAR 5:001 Section Reference
1	Financial Exhibit	12 (2)
1	Amount and kinds of stock authorized	12(2)(a)
1	Amount and kinds of stock issued and outstanding	12(2)(b)
1	Terms of preference or preferred stock	12(2)(c)
1	Brief description of each mortgage on property of Apache Gas	12(2)(d)
1	Amount of bonds authorized and issued and related information	12(2)(e)

1	Notes outstanding and related information	12(2)(f)
2	Other indebtedness and related information	12(2)(g)
2	Dividend information	12(2)(h)
3-6	Detailed Income Statement and Balance Sheet	12(2)(i)

36. A description of Apache Gas' property, its field of operation and the original cost and the cost to Apache Gas are contained in Exhibit H.

37. The description of the construction/repairs to take place along with the cost estimates are included in the testimony of David Thomas Shirey, Jr. and Jason R. Brangers. Copies of the estimates received for the work to be performed by outside contractors are attached as Exhibit C.

REQUEST FOR IMPLEMENTATION OF A SURCHARGE AND OTHER NECESSARY APPROVALS

38. The policy statements included by the General Assembly in the laws governing natural gas utilities could not be clearer. Safety is important. The policy of the Commonwealth of Kentucky, as set forth in KRS 278.509, recognizes that flexible regulatory treatment is necessary for the efficient upgrading of natural gas delivery systems, thereby yielding safer and more reliable service to customers.

39. In connection with the PRP initiative, Apache Gas and Burkesville Gas are also seeking approval of Rider PRP as a surcharge recovery mechanism. It will allow the Company to track and recover the costs of the PRP in a manner that is consistent with, but avoids the administrative and financial burden of, annual and/or multiple rate cases. Specifically, the Company proposes to provide the Commission, on an annual basis, with the following: (1) the proposed survey work with projected costs for the coming year (12

months); (2) the proposed construction plans with projected costs for the coming year (12 months); (3) the actual construction results and corresponding costs for the prior year (12 months); (4) a calculation to derive monthly customer charges for the coming year (12 months); and (5) and any other information that the Commission deems appropriate. The proposed tariff language for Rider PRP is attached hereto as Attachment DTS-1. The customer notice sent from Apache Gas to Burkesville Gas is attached as Exhibit I. A copy of the notice is also posted at Apache Gas' office in Burkesville, Kentucky. The customer notice published in the newspaper on Wednesday, April 12, 2017 by Burkesville Gas for its customers is attached as Exhibit J. The customer notice for Burkesville Gas will be published once a week for 3 consecutive weeks and will posted at its office located in Burkesville, Kentucky. Neither Apache Gas nor Burkesville Gas have a web site.

40. The Company seeks initial Commission approval of Rider PRP as described in the Direct Testimony of Company Witness David Thomas Shirey, Jr. and as set forth in Exhibit F based upon forecasted expenditures in 2017. For each subsequent year of the program, the Company will submit an application and supporting schedules on or about October 1st reflecting its intent to update the Rider PRP monthly charges based upon anticipated expenditures for the next calendar year and to true-up for the current/previous years' actual expenditures. The annual application will, among other things, reflect actual costs incurred as of October 1st and estimated costs for the balance of the year. Assuming that Commission approval is granted, the new monthly charges become effective the following January 1st.

TESTIMONY AND EXHIBITS

41. Additional facts supporting this Application are set forth in the following

Direct Testimony attached to this Application as Exhibits K through L:

a. David Thomas Shirey, Jr., President of Apache Gas and President of Burkesville Gas, discusses Apache Gas' operations, integrity management programs and the need for the project. Mr. Shirey will also testify on behalf of Apache Gas and Burkesville Gas regarding the PRP Surcharge Mechanism, the likely rate impact of the surcharge mechanism, and the need for the project;[8]

b. Jason R. Brangers, Vice President of Operations, Utility Safety and Design, Inc., discusses the PRP construction and specifications;[9]

REQUEST FOR EXPEDITED TREATMENT

42. Apache Gas and Burkesville Gas are requesting expedited treatment of this matter so that the repairs can begin as quickly as possible.

WHEREFORE, Apache Gas and Burkesville Gas respectfully request that the Commission:

1) Issue a CPCN for replacement and repair of the natural gas pipelines described herein;
2) Authorize the implementation of a surcharge mechanism to be known as Rider PRP;
3) Approve the financing described herein for the project;
4) Expedite the processing of this matter; and
5) Grant any other relief to which the Companies may be entitled.

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[8] Exhibit K.

[9] Exhibit L.

VERIFICATION

STATE OF Texas)
) SS:
COUNTY OF Hunt)

The undersigned, David Thomas Shirey being duly sworn, deposes and says that he is the President of Apache Gas Transmission Company, Inc., and the President of Burkesville Gas Company, Inc., that he has personal knowledge of the matters set forth in the foregoing, and that the information contained therein is true and correct to the best of his knowledge, information and belief.

APACHE GAS TRANSMISSION COMPANY, INC.
BURKESVILLE GAS COMPANY, INC.
By:____________________________

David Thomas Shirey, Affiant
President, Apache Gas Transmission Company, Inc.
President, Burkesville Gas Company, Inc.

Subscribed and sworn to before me by David Thomas Shirey, Jr., President of Apache Gas Transmission Company Inc., and Burkesville Gas Company, Inc., on this 10 day of April, 2017.

Erin Clark
NOTARY PUBLIC

ERIN CLARK
Notary Public
State of Texas
ID # 130585213
My Comm. Expires 03-16-2020

My Commission Expires: 3/16/20

Respectfully submitted,

L. Allyson Honaker
David S. Samford
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Counsel for Apache Gas Transmission Company, Inc. and Burkesville Gas Company, Inc.

EXHIBIT LIST

Exhibit A	Apache Gas' request for Staff Opinion
Exhibit B	PSC Staff Opinion
Exhibit C	Contractor Proposals
Exhibit D	Maps and Drawings
Exhibit E	PRP Specifications and Regulations
Exhibit F	Cost breakdown analysis and proposed PRP surcharge rates
Exhibit G	807 KAR 5:001 Section 12 Financial Exhibit
Exhibit H	Description of property, original cost and cost to Apache Gas
Exhibit I	Apache Gas' customer notice
Exhibit J	Burkesville Gas' customer notice
Exhibit K	Direct Testimony of David Thomas Shirey, Jr.
	Exhibit DTS-1 - Letter from First and Farmers Bank
	Exhibit DTS-2 – Proposed Tariffs
Exhibit L	Direct Testimony of Jason Brangers

Apache Gas Transmission Company, Inc.
a Kentucky Corporation

Business Mailing Address
P.O. Box, Emory, Texas 75440
Telephone (903) 274-4322 - eFax (888) 823-7417

July 8, 2013

Via USPS Priority and Email

Jeff R. Derouen
Executive Director
Kentucky Public Service Commission
2110 Sower Blvd.
Frankfort, Kentucky 40602

Re: Burkesville Gas Company, Inc. ("BGC") and Apache Gas Transmission Company, Inc. ("Apache") and the proposed main replacement project

Mr. Derouen,

On July 1, 2013 I met with Staff members Leah Faulkner, Jason Brangers and Ron Handziak concerning a matter relating to referenced matter.

As a brief background, Apache is a Kentucky Corporation that owns the 21-mile intra state natural gas transmission line from the Texas Interconnect in Metcalf County, Kentucky to the Burkesville City Gate near Burkesville, Kentucky. Currently Apache's only customer is BGC. For ratemaking purposes, it has been determined by the commission that Apache was a Kentucky utility. In 2007 (case # 2007-00354) Apache filed an Application for Rate Adjustment before the Public Service Commission for small utilities pursuant to KAR 5:076.

Currently there is a need to replace four (4) certain sections of main transmission line due to natural erosion. This transmission line is the only line that supplies natural gas to the City of Burkesville. We have become aware of the KRS 278.509 recovery of costs for investment in natural gas pipeline replacement program and would like to proceed with this method for recovering the cost of this proposed project. The following are some details about the proposed main replacement project.

1. Preliminary cost estimates provided by Martin Contracting, Inc. indicate that the total main replacement project will cost less than $70,000.
2. Apache is responsible for maintaining 21 miles of natural gas pipeline and the total amount of mains that needs to be replaced due to erosion is 0.4947 miles or about 2.36% of to total 21 mile transmission line.
3. The mains that needs to replaced is an area that is a steeper grade and has a higher rock content than Apache or BGC is directly able to accommodate.

I have a few questions relating to this matter.

1. Since Apache has been considered a Kentucky Utility for ratemaking purposes in the past, will Apache be permitted to recovery of costs for investment in natural gas pipeline replacement under KRS 278.509?
2. Will Apache be required to apply for a certificate of public convenience and necessity ("CPCN") from the Commission prior to constructing improvements?

3. In an effort to keep cost down, since we are proposing to replace existing mains line with the same or larger mains and with the same or greater operating limits as is currently installed, can this main replacement be done in the ordinary course of business and not require the services of an engineer?
4. Additionally, in an effort to keep cost down, is recovery of costs for investment in natural gas pipeline replacement program under KRS 278.509 something we can apply for directly without the services of an attorney?

Thank you for your consideration in this matter. I would like to express appreciation to Leah Faulkner, Jason Brangers and Ron Handziak that were very helpful and informative. If you have any questions please let me know.

Sincerely,

Tom Shirey
President
Apache Gas Transmission Company, Inc.

Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

Commonwealth of Kentucky
Public Service Commission
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David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Linda Breathitt
Commissioner

August 29, 2013

Mr. Tom Shirey
President
Apache Gas Transmission Company, Inc.
2718 Wesley Street
Greenville, TX 75401

Re: Apache Gas Transmission Company, Inc. Request for an Advisory Opinion — **PSC STAFF OPINION 2013-009**

Dear Mr. Shirey:

Commission Staff acknowledges receipt of your July 8, 2013 letter in which you request an opinion concerning a gas transmission line replacement project proposed by Apache Gas Transmission Company, Inc. ("Apache"). This opinion represents Commission Staff's interpretation of the law as applied to the facts presented, is advisory in nature, and is not binding on the Commission should the issues herein be formally presented for Commission resolution.

Based upon your letter, Commission Staff understands the facts as follows:

> Apache is a Kentucky Corporation that owns a 21-mile intrastate natural gas transmission line that extends from Metcalf County, Kentucky to Burkesville, Kentucky. Apache's only customer is Burkesville Gas Company, Inc. ("BGC") in Burkesville, Kentucky. The Commission has previously treated Apache as a utility for rate making purposes in Apache's 2007 application for an adjustment of rates pursuant to the alternative rate filing procedure in case number 2007-00354. Apache states that it presently needs to replace 0.4947 miles of natural gas pipeline at a cost of approximately $70,000.[1]

[1] Apache has since provided a revised cost estimate of the project in the range of $117,925 to $190,530. E-mail from Tom Shirey, President, Apache Gas Transmission Company, Inc. to Leah Faulkner, Manager, Kentucky Public Service Commission (Aug. 7, 2013). Attached as Exhibit A.

You pose four questions to the Commission. First, whether Apache will be permitted to recover the costs of the aforesaid project pursuant to KRS 278.509; second, whether a Certificate of Public Convenience and Necessity ("CPCN") will be required for the project; third, whether the project would be deemed to be in the ordinary course of business and, therefore, not require the employment of a project engineer; and fourth, whether Apache may submit an application to the Commission for recovery, absent the services of an attorney.

KRS 278.509 permits a regulated utility to recover the costs of its "investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility." The expenses may only be recovered upon a finding by the Commission that the costs are "fair, just and reasonable."[2]

Pursuant to KRS 278.010(3), utility service includes "[t]he transporting or conveying of gas . . . by pipeline to or for the public, for compensation." In instances wherein an otherwise non-regulated entity sells gas to an affiliated regulated utility, the unregulated business will also be deemed a utility "to the extent necessary to ensure that the rates charged the utility and ultimately to the consumer are just and reasonable." KRS 278.274(3)(b). Companies are affiliated when "[o]ne or more of the owners control or have the right to control the business affairs of all affected companies."[3]

The statutory provision permitting recovery of costs for investments in natural gas pipeline replacement programs is explicitly limited to regulated utilities. As defined by KRS 278.010, a regulated utility is an entity that performs an enumerated service, such as the transportation of gas, to the public and for compensation. An entity provides service to or for the public when it offers to or is willing to serve all individuals to the extent of the available facilities.[4]

Apache and BGC have common principals controlling the operations of both companies.[5] They are considered sister companies.[6] Therefore, Apache is deemed to

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[2] KRS 278.509.

[3] KRS 278.274(3)(a).

[4] Case No. 89-322, *The Application of Electric Energy, Inc. for a Certificate of Convenience and Necessity to Construct a Power Transmission* (Ky. PSC Nov. 1, 1989).

[5] *Annual Report of Burkesville Gas Company, Inc. to the Public Service Commission* for the calendar year ended December 31, 2011 at 1.

[6] Case No. 2007-00354, *Application of Apache Gas Transmission Company, Inc. for an Adjustment of Rates Pursuant to the Alternative Rate Filing Procedure for Small Utilities* (Ky. PSC Dec. 21, 2007).

be affiliated with BGC.[7] As a result, Apache is subject to the Commission's jurisdiction to ensure the rates it charges to BGC, as an affiliate, are just and reasonable to the extent authorized by KRS 278.274.

As Apache is treated as a utility under KRS 278.010 in regard to the rates it charges, Apache may avail itself of the rate recovery mechanisms devised by the legislature to include KRS 278.509, which provides for the recovery of investments in pipeline replacement programs not otherwise recovered through existing rates. Upon submission of an application for rate recovery, as provided for by both KRS 278.274 and KRS 278.509, the Commission is charged with determining whether the rate recovery is fair, just and reasonable.

As to the second and third questions posed, KRS 278.020(1) provides that:

> No person, partnership, public or private corporation, or combination thereof shall commence providing utility service to or for the public or begin the construction of any plant, equipment, property or facility for furnishing to the public any of the services enumerated in KRS 278.010 except . . . ordinary extensions of existing systems in the usual course of business, until that person has obtained from the Public Service Commission a certificate that public convenience and necessity require the service or construction.

The Commission has adopted a regulation, 807 KAR 5:001, Section 15(3), which defines "ordinary extensions" that do not require a CPCN as follows:

> Extensions in the ordinary course of business. A certificate of public convenience and necessity shall not be required for extensions that do not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates or service of other utilities operating in the same area and under the jurisdiction of the commission that are in the general or contiguous area in which the utility renders service, and that do not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved, or will not result in increased charges to its customers.

A CPCN is required prior to a regulated utility commencing construction on a project that is not within the ordinary course of business.[8] A project is *per se* not within

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[7] KRS 278.274(3)(b).

[8] KRS 278.020(1); 807 KAR 5:001 Section 15(3).

the ordinary course of business when it will result in increased charges to customers, and here Apache intends to propose a contemporaneous request to pass on the project's costs through an increase in rates or assessment of a surcharge.[9] Moreover, the rate recovery mechanism in KRS 278.509 is contingent upon a finding by the Commission that the project is necessary and that the corresponding rate assessment is just and reasonable. Absent an examination of the underlying construction to ascertain whether the proposed project is necessary and reasonable, the Commission would be stymied in attempting to assess the propriety of the requested rate increase in conjunction with KRS 278.509. Accordingly, the construction project coupled with a simultaneous rate increase, as proposed by Apache, requires a CPCN.

Commission regulations also require applications for CPCNs to include descriptions of the need and manner for which the proposed project will be constructed.[10] Reports, drawings and plans submitted to the Commission must be signed by a Licensed Professional Engineer and bear the engineer's stamp or seal.[11] A professional engineer must be engaged in all projects that require a CPCN, regardless of whether the project entails new construction or replacement of existing facilities. Therefore, the services of an engineer would be required for the proposed main replacement project as a requirement of the application for a CPCN.

Finally, the practice of law is broadly defined by Kentucky Supreme Court Rule 3.020, which states:

> The practice of law is any service rendered involving legal knowledge or legal advice, whether of representation, counsel or advocacy in or out of court, rendered in respect to the rights, duties, obligations, liabilities or business relations of one requiring the services.

The practice of law includes representation of a party before a state administrative agency.[12] The Commission has required that those representing the interests of others must be licensed attorneys. The Commission has previously held:

> [A]ny attorney who is not licensed to practice in the State of Kentucky and who seeks to represent a client or employer before this Commission must engage a member of the

[9] 807 KAR 5:001 Section 15(3).

[10] 807 KAR 5:001 Section 15(2).

[11] KRS 322.340.

[12] *Kentucky State Bar Association v. Henry Vogt Machine Co.*, 416 S.W.2d 727, 728 (Ky. 1967).

> Kentucky Bar Association. It logically follows that if an unlicensed attorney may not represent a client before this Commission, neither may a layman.[13]

Practice before the Commission by the representative of a corporation necessarily requires retainer of an attorney.[14] Commission regulations preclude a person, other than an attorney, from filing papers on behalf of another person in the course of a formal proceeding, which includes applications for a CPCN under KRS 278.020 and rate recovery pursuant to KRS 278.509.[15] The papers must also be signed and filed by an attorney.[16] A person is defined to include a corporation, thereby precluding a non-attorney from filing papers on behalf of a corporation.[17] Furthermore, an appearance before the Commission in the course of a formal hearing constitutes the practice of law. Consequently, the services of an attorney licensed in the Commonwealth of Kentucky will be required for Apache to proceed with the proposed applications.

This letter represents Commission Staff's interpretation of the law as applied to the facts presented. This opinion is advisory in nature and is not binding on the Commission should the issues herein be formally presented for Commission resolution. Questions concerning this opinion should be directed to Virginia Gregg or Jonathan Beyer, Commission counsel at (502) 564-3940.

Sincerely,

Jeff Derouen
Executive Director

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[13] Case No. 2004-00348, *Howard B. Keen v. Carroll County Water District* (PSC Ky. Oct. 15, 2004) (*citing* Administrative Case No. 249, Practice Before the Commission by Attorneys Non-Licensed in the Commonwealth of Kentucky (Ky. PSC June 15, 1981)).

[14] *Vogt Machine*, 416 S.W.2d at 728.

[15] 807 KAR 5:001 Section 4(4).

[16] *Id.*

[17] KRS 278.010(3).

Ex. A

From: Tom Shirey [mailto:dtshireyll@gmail.com]
Sent: Wednesday, August 07, 2013 3:09 PM
To: Faulkner, Leah (PSC)
Cc: 'Brenda Everette'
Subject: RE: Apache Gas Transmission Company, Inc. request for determination

Leah,

Hope you are having a great summer. Have you heard anything about our request for an executive determination relating to Apache Gas Transmission Company being able to file under KRS 278.509 for recovery of costs for natural gas pipeline replacement? Since I met with you, Ronald and Jason on July the 1st we have received a closer estimate from a utility pipe contractor after a site inspection of the areas that need to be replaced. The current estimate is more than first estimated. The current estimated cost to replace the sections of pipe is between $117,925 and $190,530 depending on options and the time over which the repairs are to be completed. As before, these estimates are without the costs of an engineer or attorney.

Thank you,

Tom
Apache Gas Transmission Company, Inc.

903.268.4322 - Skype
903.268.5122 - cell
888.823.7417 - efax
dtshireyll@gmail.com

Apache Gas Transmission Company, Inc.
a Kentucky Corporation

Business Mailing Address
P.O. Box, Emory, Texas 75440
Telephone (903) 274-4322 - eFax (888) 823-7417

July 8, 2013

RECEIVED

JUL 0 8 2013

PUBLIC SERVICE
COMMISSION

Via USPS Priority and Email

Jeff R. Derouen
Executive Director
Kentucky Public Service Commission
2110 Sower Blvd.
Frankfort, Kentucky 40602

Re: Burkesville Gas Company, Inc. ("BGC") and Apache Gas Transmission Company, Inc. ("Apache") and the proposed main replacement project

Mr. Derouen,

On July 1, 2013 I met with Staff members Leah Faulkner, Jason Brangers and Ron Handziak concerning a matter relating to referenced matter.

As a brief background, Apache is a Kentucky Corporation that owns the 21-mile intra state natural gas transmission line from the Texas Interconnect in Metcalf County, Kentucky to the Burkesville City Gate near Burkesville, Kentucky. Currently Apache's only customer is BGC. For ratemaking purposes, it has been determined by the commission that Apache was a Kentucky utility. In 2007 (case # 2007-00354) Apache filed an Application for Rate Adjustment before the Public Service Commission for small utilities pursuant to KAR 5:076.

Currently there is a need to replace four (4) certain sections of main transmission line due to natural erosion. This transmission line is the only line that supplies natural gas to the City of Burkesville. We have become aware of the KRS 278.509 recovery of costs for investment in natural gas pipeline replacement program and would like to proceed with this method for recovering the cost of this proposed project. The following are some details about the proposed main replacement project.

1. Preliminary cost estimates provided by Martin Contracting, Inc. indicate that the total main replacement project will cost less than $70,000.
2. Apache is responsible for maintaining 21 miles of natural gas pipeline and the total amount of mains that needs to be replaced due to erosion is 0.4947 miles or about 2.36% of to total 21 mile transmission line.
3. The mains that needs to replaced is an area that is a steeper grade and has a higher rock content than Apache or BGC is directly able to accommodate.

I have a few questions relating to this matter.

1. Since Apache has been considered a Kentucky Utility for ratemaking purposes in the past, will Apache be permitted to recovery of costs for investment in natural gas pipeline replacement under KRS 278.509?
2. Will Apache be required to apply for a certificate of public convenience and necessity ("CPCN") from the Commission prior to constructing improvements?

3. In an effort to keep cost down, since we are proposing to replace existing mains line with the same or larger mains and with the same or greater operating limits as is currently installed, can this main replacement be done in the ordinary course of business and not require the services of an engineer?
4. Additionally, in an effort to keep cost down, is recovery of costs for investment in natural gas pipeline replacement program under KRS 278.509 something we can apply for directly without the services of an attorney?

Thank you for your consideration in this matter. I would like to express appreciation to Leah Faulkner, Jason Brangers and Ron Handziak that were very helpful and informative. If you have any questions please let me know.

Sincerely,

Tom Shirey
President
Apache Gas Transmission Company, Inc.

2371 Irvine Rd.
Richmond, KY 40475

SHAWN MARTIN
OWNER

Martin Contracting Inc.

Tel 859-623-0112
Cell 606-305-5454

Apache Gas Transmission Company, Inc.
119 Upper River St,
Burkesville, KY 42717

ATTENTION: Tom Shirey

EMAIL: dtshireyll@gmail.com

PROPOSAL & TERMS

Re: Relocate 900' of 6" Poly Gas Line

March 24th, 2017

Martin Contracting, Inc. will supply all labor, equipment, & materials to complete the following at a price not to exceed $60,000.00:

DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	EXTENDED TOTAL
Labor to Install 900' of 6" Poly	900	LF	$ 32.00	$ 28,800.00
Materials to Install 900' of 6" Poly	900	LF	$ 20.70	$ 18,630.00
Subtotal				$ 47,430.00
Overhead			15.00%	$ 7,114.50
Profit			10.00%	$ 5,454.45
	TOTAL PRICE			**$ 59,998.95**

Martin contracting will proceed with work within 10 days of NTP. Project duration is expected to be approximately 10 days.

Submitted by:

Shawn Martin, President
Martin Contracting, Inc.

Accepted by:

Tom Shirey
Apache Gas Transmission Company, Inc.

A & C COMMUNICATIONS CORPORATION

"Building Tomorrows Telecommunications Systems Today"

March 23, 2017

Mr. Tom Shirey
Apache Gas Company, Inc.
119 Upper River Street
Burkesville, Ky 42717

Mr. Shirey

A & C Communications respectfully submits the following price quote on the above referenced job for

your review and approval:

Open ditch and backfill on Allens Creek Doug Lewis property from top of hill at fence line to valve at bottom of hill.

Amount not to exceed $ 17,403.20

Open ditch on south side of Doug Lewis residence.

Amount not to exceed $ 3,000.00

Crew can be on site within 30 days of notice given.
Regards,

Heyward Adams

Heyward Adams, President
A & C Communications Corporation

Cc:

Approved: Date:

Apache Gas Company, Inc.:______________________________

1118 Garrett Creek Rd.
Burkesville, KY
42717

PHONE (270) 433-7676
FAX (270) 433-7575
E-MAIL heyward@a-ccommunications.com
WEB SITE www.a-ccommunications.com

BURKESVILLE GAS COMPANY, INC.

119 Upper River St. - P. O. Box 69, Burkesville, Kentucky 42717
Telephone (270) 864-9400 - Fax (270) 864-5135

Business Office Address
P.O. Box 385 Emory, Texas 75440
Fax (888) 823-7417

March 31, 2017

Apache Gas Transmission Company, Inc.
Burkesville, Kentucky

Re: Pipeline Replacement Project 2017

Burkesville Gas Company, Inc will supply, pipe fusing labor, install 6" poly pipe and valve, pipe testing, purging, tie-ins, backfill aggerate, all materials, assistance and oversite as needed to complete the Doug Lewis B Section and Allen Creek Road drainage ditch crossing repair at a price not to exceed $18,000.

Burkesville Gas Company, Inc will supply one additional high density 6"" valve, assistance and oversite as needed to complete the Cliff Norris Section repair at a price not to exceed $6,000.

Description	Amount	Totals
Doug Lewis B Section up-grade		
Pipe Fusing, Installing, Testing, Purging, Tie-Ins	5,000.00	
Additional Back-Fill Aggerate	2,000.00	
751 feet of 6" High Density Poly Pipe	4,491.00	
One 6" High Density Poly Valve	257.94	
Other miscellaneous fittings, tracer wire and marker tape	400.00	
Oversite and Assistance	2,500.00	
Doug Lewis B total		**14,648.94**
Allen Creek Rd drainage ditch crossing repair		
Pipe Fusing, Installing, Testing, Purging, Tie-Ins	1,000.00	
Additional Back-Fill Aggerate	400.00	
100 feet of 6" High density poly pipe	598.00	
6" high density poly valve	257.94	
Oversite and Assistance	1,000.00	
Allen Creek Rd drainage ditch crossing		**3,255.94**
Cliff Norris Section up-grade		
Two Additional 6" High Density PolyValves	516.00	
Oversite and Assistance	5,400.00	
Cliff Norris Section up-grade Total		**5,916.00**
Total Burkesville Gas Company, Inc. Proposal		**23,820.88**

Burkesville Gas Company, Inc. will proceed with work within 10 days of Notice to Proceed and upon other project utility contractor beginning work.

Submitted by:
Burkesville Gas Company, Inc.

APACHE GAS TRANSMISSION 2017 PIPELINE REPLACEMENT PROJECT

SHEET INDEX:

A-01	NOTES AND MATERIALS
PR-01	CLIFF NORRIS SECTION
PR-02	DOUG LEWIS SECTION B
PR -03	ALLEN CREEK ROAD DRAINAGE DITCH SECTION

Designed By: J. Brangers

Drawn By: S. Pine

REV	DATE	DRWN	APP'D	REVISION DESCRIPTION
1	3/31/2017	SDP	JRB	FOR REVIEW

2017 REPLACEMENT PROJECT
APACHE GAS TRANSMISSION

USDI www.usdi.us
UTILITY SAFETY & DESIGN INC
P.O. BOX 727
SHELBYVILLE, KENTUCKY 40066
PHONE: 502-513-51272
www.usdi.us

COVER

SHEET C-01

SCOPE OF WORK

1. REPLACE, INSTALL, TEST, AND COMMISSION THREE SECTIONS OF EXPOSED PIPELINE LOCATED IN CUMBERLAND COUNTY, KENTUCKY ON THE APACHE GAS TRANSMISSION PIPELINE WITH 6" HIGH DENSITY POLYETHYLENE (PE). THE THREE SECTIONS ARE REFERRED TO AS THE CLIFF NORRIS SECTION, THE DOUG LEWIS SECTION B, AND THE ALLEN CREEK ROAD DRAINAGE DITCH SECTION. APPROXIMATELY 900', 750' AND 100' OF EXISTING PIPELINE WILL BE REPLACED WITH 6" HDPE ON THE CLIFF NORRIS SECTION, DOUG LEWIS SECTION B, AND ALLEN CREEK ROAD DRAINAGE DITCH SECTION RESPECTIVELY.

2. INSTALL, TEST, AND COMMISSION FOUR (4) NEW SYSTEM VALVES AT THE THREE DIFFERENT SITES.

3. THE MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP) OF THE 6" HDPE PIPELINE WILL BE 100 PSIG.

4. THE NEWLY INSTALLED PIPE AND VALVES SHALL BE PRESSURE TESTED IN ACCORDANCE WITH 49 CFR 192.513 TO ENSURE DISCOVERY OF ALL POTENTIALLY HAZARDOUS LEAKS IN THE SEGMENT BEING TESTED. THE TEST PRESSURE MUST BE AT LEAST 150 PERCENT OF THE MAXIMUM OPERATING PRESSURE, BUT NOT MORE THAN THREE TIMES THE DESIGN PRESSURE DETERMINED UNDER 49 CFR 192.121. THEREFORE, THE TEST PRESSURE MUST BE AT LEAST 150 PSIG (MAOP OF 100 PSIG X 150%) AND MUST NOT BE MORE THAN 306 PSIG (DESIGN PRESSURE OF 102 PSIG X 3). TIE-IN FUSES SHALL BE LEAK TESTED AT OPERATING PRESSURE.

5. THE LOCATION OF THE PIPELINE OR VALVES AND OTHER APPURTENANCES SHALL NOT BE SIGNIFICANTLY MODIFIED FROM THAT SHOWN ON THE PLANS WITHOUT PRE-APPROVAL FROM APACHE GAS TRANSMISSION COMPANY'S PIPELINE PROJECT REPRESENTATIVE.

TYPICAL CONSTRUCTION NOTES

1. ALL CONSTRUCTION SHALL BE PERFORMED AND CONDUCTED IN ACCORDANCE WITH APPLICABLE STATE AND FEDERAL PIPELINE SAFETY REGULATIONS (I.E. 49 CFR 192)

2. PERSONNEL PERFORMING COVERED TASKS SHALL MEET THE REQUIREMENTS OF 49 CFR 192 SUPBPART N - QUALIFICATION OF PIPELINE PERSONNEL
   - CONTRACTOR SHALL PROVIDE A COPY OF THE FOLLOWING
     - OPERATOR QUALIFICATION PLAN
     - EVALUATIONS OF INDIVIDUALS PERFORMING COVERED TASKS ON THIS FACILITY
     - FUSION QUALIFICATIONS AND CERTIFICATES FOR INDIVIDUALS PERFORMING FUSION AND ASSOCIATED TASKS
     - DRUG AND ALCOHOL PLAN AND PROOF OF PARTICIPATION

3. TRANSMISSION LINE MUST BE CONSTRUCTED IN ACCORDANCE WITH 49 CFR 192 SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS.

4. COMPLY WITH THE REQUIREMENTS OF 49 CFR 192 FOR MATERIALS, INSTALLATION, TESTING, INSPECTION, AND PURGING.

5. INSTALL POLYETHYLENE(PE) MAIN, ALONG WITH APPROPRIATE TRACER WIRE, WARNING TAPE, AND BACKFILL MATERIAL.

6. REPLACE OR RELOCATE ALL SIGNS DAMAGED OR REMOVED DUE TO CONSTRUCTION.

7. EXISTING DITCHES, DRAINAGES, ETC. CROSSED BY OPEN CUT EXCAVATION SHALL BE RESTORED TO PRE-CONSTRUCTION CONDITION. DO NOT FILL.

8. THE CONTRACTOR SHALL VERIFY THE DEPTH OF THE WATER FEATURES (E.G.: PONDS, CREEKS, DITCHES, DRAINAGES, ETC.) ALONG THE ALIGNMENT OF THE PIPELINE.

9. THE CONTRACTOR SHALL BE REQUIRED TO EXPOSE AND ADEQUATELY SUPPORT THE EXISTING PIPELINE WHERE WORK IS TO BE CONDUCTED.

10. PIPELINE MARKERS AND WARNING SIGNS SHALL BE REPLACED AND RECORDED, IF NECESSARY, BY THE CONTRACTOR AS SPECIFIED IN THE CONTRACT DOCUMENTS.

11. RESTORE ALL LANDSCAPING AND CONCRETE STRUCTURES SUBJECT TO REMOVAL DURING CONSTRUCTION TO ORIGINAL OR BETTER CONDITION.

12. STORE PE PIPE AND VALVES PROTECTED FROM DIRECT SUNLIGHT AND PROPERLY SUPPORT PE PIPE TO PREVENT UNDUE SAGGING AND BENDING

13. THE PIPE MUST BE INSTALLED SO AS TO MINIMIZE STRESS ON THE PIPELINE.

14. BACKFILL SHALL OF SUITABLE MATERIAL AND SHALL PROVIDE FIRM SUPPORT UNDER THE PIPE AND PREVENT DAMAGE TO THE PIPE COATING.

15. THE PIPELINE MUST BE INSTALLED WITH AT LEAST TWELVE INCHES (12") OF CLEARANCE FROM ALL OTHER PIPELINES AND STRUCTURES NOT ASSOCIATED WITH THE PIPELINE. IF THIS CLEARANCE CANNOT BE OBTAINED THEN THE TRANSMISSION LINE MUST BE PROTECTED FROM ANY DAMAGE FROM THE OTHER STRUCTURE, SUCH AS WITH PLASTIC CASINGS, SHIELDS, ETC. CLEARANCES MUST BE MAINTAINED TO ALLOW PROPER MAINTENANCE OF THE PIPELINE.

16. THE PIPELINE SHALL BE INSTALLED WITH MINIMUM COVER IN ACCORDANCE WITH 49 CFR 192.327, AS SHOWN BELOW

LOCATION	NORMAL SOIL INCHES	CONSOLIDATED ROCK INCHES
CLASS 1	30	18
CLASS 2,3, & 4	36	24
DRAINAGE DITCHES OF PUBLIC ROADS AND RAILROAD CROSSINGS	36	24

GENERAL NOTES

1. THE CONTRACTOR WILL BE RESPONSIBLE FOR VERIFYING ALL EXISTING UTILITIES IN THE FIELD. CALL FOR UTILITY LOCATES 48 HOURS PRIOR TO BEGINNING OF CONSTRUCTION. EXISTING UTILITIES, WHETHER SHOWN ON THE PLANS OR NOT, SHALL BE LOCATED PRIOR TO CONSTRUCTION SO AS TO AVOID DAMAGE OR DISTURBANCE.

2. CONTRACTOR SHALL ASSUME ALL RESPONSIBILITY AND COSTS CONNECTED WITH LOCATION AND PROTECTION OR EXISTING UTILITIES.

3. CONTRACTOR ASSUMES SOLE RESPONSIBILITY FOR WORKER SAFETY, AND DAMAGE TO STRUCTURES AND IMPROVEMENTS RESULTING FROM CONSTRUCTION OPERATIONS.

4. ALL TRENCH EXCAVATION OPERATIONS SHALL MEET OR EXCEED ALL APPLICABLE SHORING LAWS FOR TRENCHES. ALL TRENCH SAFETY SYSTEMS SHALL MEET OSHA AND STATE REQUIREMENTS.

5. AT LEAST 48 HOURS BEFORE COMMENCING PROJECT WORK, NOTIFY THE APPROPRIATE PERMITTING AGENCIES AND UTILITY COMPANIES.

6. CONTRACTOR SHALL MAINTAIN ALL PERMITS AND A COPY OF THE CONTRACT DOCUMENTS AT THE PROJECT SITE AT ALL TIMES.

7. ALL WORK SHALL CONFORM TO THE CONTRACT DOCUMENTS. AND CHANGES FROM THE APPROVED PLANS REQUIRE PRE-APPROVAL FROM APACHE GAS TRANSMISSION COMPANY'S PIPELINE PROJECT REPRESENTATIVE.

8. WORK SHALL BE PERFORMED IN ACCORDANCE WITH ALL FEDERAL, STATE AND LOCAL LAWS, CODES AND ORDINANCES.

EASEMENT NOTES

1. CONTRACTOR SHALL LIMIT ALL CONSTRUCTION ACTIVITY WITHIN THE ACQUIRED PERMANENT AND TEMPORARY CONSTRUCTION EASEMENTS WITHOUT EXCEPTION, UNLESS PRE-APPROVED BY APACHE GAS TRANSMISSION COMPANY'S PIPELINE PROJECT REPRESENTATIVE.

2. EASEMENTS SHALL NOT BE USED FOR THE STORAGE OF MATERIALS OR EQUIPMENT, OTHER THAN FOR TEMPORARY STAGING PURPOSES RELATED TO CURRENT CONSTRUCTION ACTIVITY.

3. CONTRACTOR IS RESPONSIBLE FOR ACQUISITION OF ALL STAGING AREA'S AND MARSHING YARDS REQUIRED FOR ITS PURPOSES, INCLUDING AND COSTS ASSOCIATED THEREWITH.

4. CONTRACTOR SHALL NOT OBTAIN ADDITIONAL EASEMENTS NOR NEGOTIATE MODIFIED EASEMENTS ON BEHALF OF APACHE GAS TRANSMISSION COMPANY'S PIPELINE PROJECT REPRESENTATIVE. IF ADDITIONAL OR MODIFIED EASEMENTS ARE REQUIRED DUE TO UNFORESEEN SITE CONDITIONS. COORDINATION WITH PROPERTY OWNERS, INCLUDING NEGOTIATIONS OF EASEMENTS RIGHTS AND ASSOCIATED COMPENSATION, SHALL BE CONDUCTED BY THE PROPERTY LIAISON. CONTRACTOR SHALL MOBILIZE TO ANOTHER SECTION OF THE PIPELINE AND RECOMMENCE CONSTRUCTION TO MINIMIZE STANDBY TIME.

5. THE CONTRACTOR SHALL MINIMIZE DISTURBANCE AND CLEANING WITHIN THE TEMPORARY EASEMENT TO ONLY THAT WHICH IS NECESSARY FOR INSTALLATION OF THE PIPELINE.

CLIFF NORRIS SECTION
MATERIALS LIST AND ESTIMATED QUANTITIES

NO	MATERIAL DESCRIPTION	UNITS	REQ'D	EXTRA	TOTAL
1	6" HDPE PIPE	FEET	900	90	990
2	6" HPDE VALVES	EACH	2	0	2
3	#12 TRACER WIRE	FEET	1,025	0	1,0254
4	PIPELINE MARKERS	EACH	10	0	10
5	WARNING BURIED GAS PIPELINE TAPE	FEET	1,025	0	1,025

DOUG LEWIS SECTION B
MATERIALS LIST AND ESTIMATED QUANTITIES

NO	MATERIAL DESCRIPTION	UNITS	REQ'D	EXTRA	TOTAL
1	6" HDPE PIPE	FEET	750	75	825
2	6" HPDE VALVES	EACH	1	0	1
3	#12 TRACER WIRE	FEET	850	0	850
4	PIPELINE MARKERS	EACH	8	0	8
5	WARNING BURIED GAS PIPELINE TAPE	FEET	850	0	850

ALLEN CREEK ROAD DRAINAGE DITCH SECTION
MATERIALS LIST AND ESTIMATED QUANTITIES

NO	MATERIAL DESCRIPTION	UNITS	REQ'D	EXTRA	TOTAL
1	6" HDPE PIPE	FEET	100	10	110
2	6" HPDE VALVES	EACH	1	0	1
3	#12 TRACER WIRE	FEET	125	0	125
4	PIPELINE MARKERS	EACH	2	0	2
5	WARNING BURIED GAS PIPELINE TAPE	FEET	125	0	125

TOTAL MATERIALS LIST AND ESTIMATED QUANTITIES

NO	MATERIAL DESCRIPTION	UNITS	REQ'D	EXTRA	TOTAL
1	6" HDPE PIPE	FEET	1,750	175	1,925
2	6" HPDE VALVES	EACH	5	0	5
3	#12 TRACER WIRE	FEET	2,000	0	2,000
4	PIPELINE MARKERS	EACH	20	0	20
5	WARNING BURIED GAS PIPELINE TAPE	FEET	2,000	0	2,000

PIPE AND VALVE SPECIFICATIONS

• PIPE MATERIAL	HIGH DENSITY POLYETHYLENE (HDPE)
• PIPE DIAMETER	SIX INCH (6")
• STANDARD DIMENSION RATIO (SDR)	ELEVEN (11)
• MATERIAL DESIGNATION	PE3408/PE4710
• QUALIFICATION OF PIPE STANDARD	ASTM D2513
• HYDROSTATIC DESIGN BASIS (73°)	1,600 PSI
• MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)	100 PSIG
• NORMAL OPERATING PRESSURE	70-80 PSIG
• MAXIMUM DESIGN PRESSURE PURSUANT TO 192.121	102 PSIG
• VALVE MATERIAL	HIGH DENSITY POLYETHYLENE (HDPE)
• VALVE SIZE	SIX INCH (6")
• STANDARD DIMENSION RATIO (SDR)	ELEVEN (11)
• MATERIAL DESIGNATION	PE3408/PE4710

Designed By: J. Brangers

Drawn By: S. Pine

REV	DATE	DRWN	APP'D	REVISION DESCRIPTION
1	3/31/2017	SDP	JRB	FOR REVIEW
2	4/11/2017		JRB	ADDED SCOPE OF WORK & PIPE/VALVE SPECS

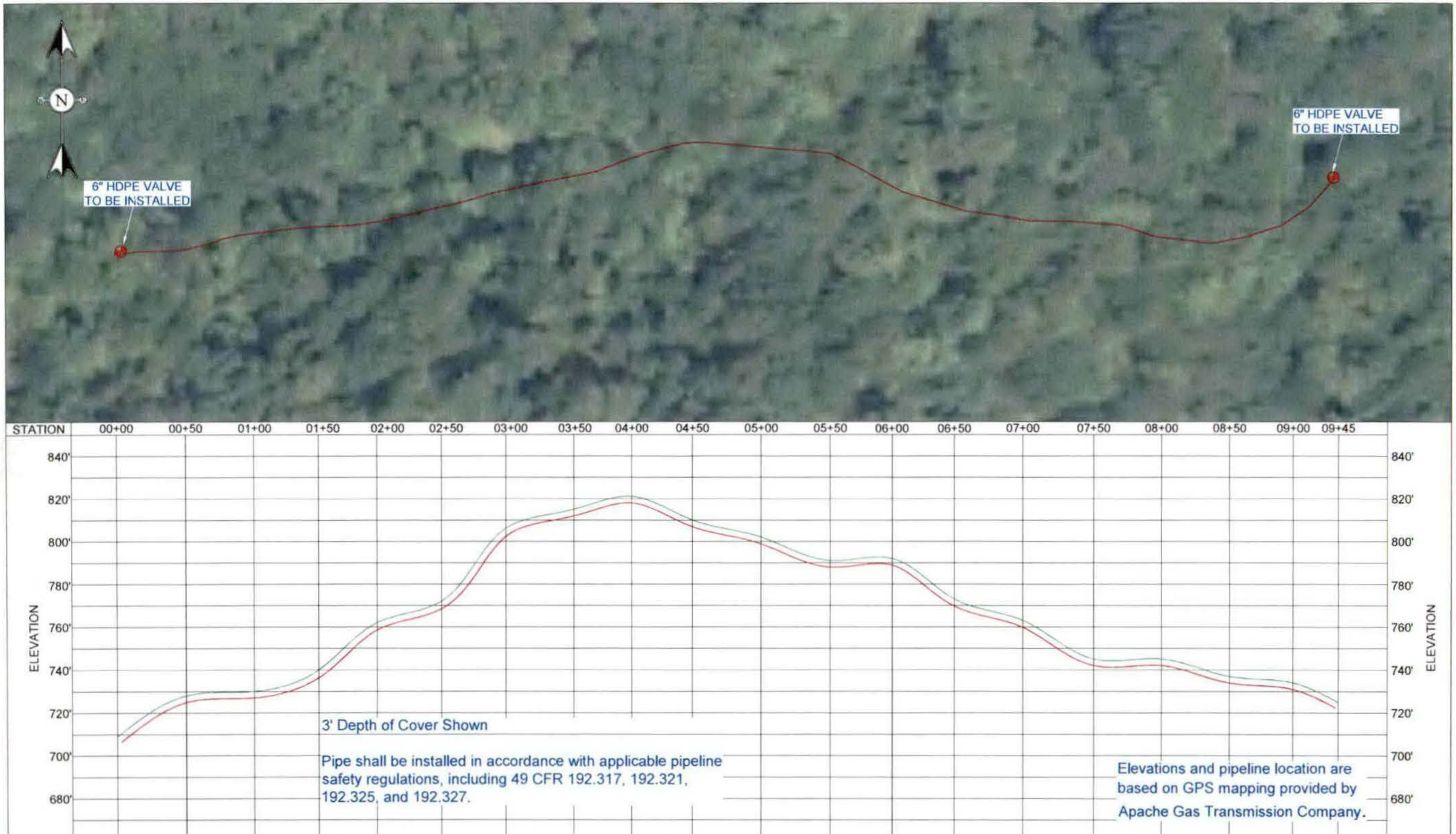
2017 REPLACEMENT PROJECT
APACHE GAS TRANSMISSION

USDI
www.usdi.us

UTILITY SAFETY & DESIGN INC
P.O. BOX 727
SHELBYVILLE, KENTUCKY 40066
PHONE: 502-513-51272
www.usdi.us

NOTES AND MATERIALS

SHEET
A-01



LEGEND:
PROPOSED 6" HDPE GAS PIPELINE
GROUND LEVEL

Designed By: J. Brangers

Drawn By: S. Pine

REV	DATE	DRWN	APP'D	REVISION DESCRIPTION
1	3/31/2017	SDP	JRB	FOR REVIEW

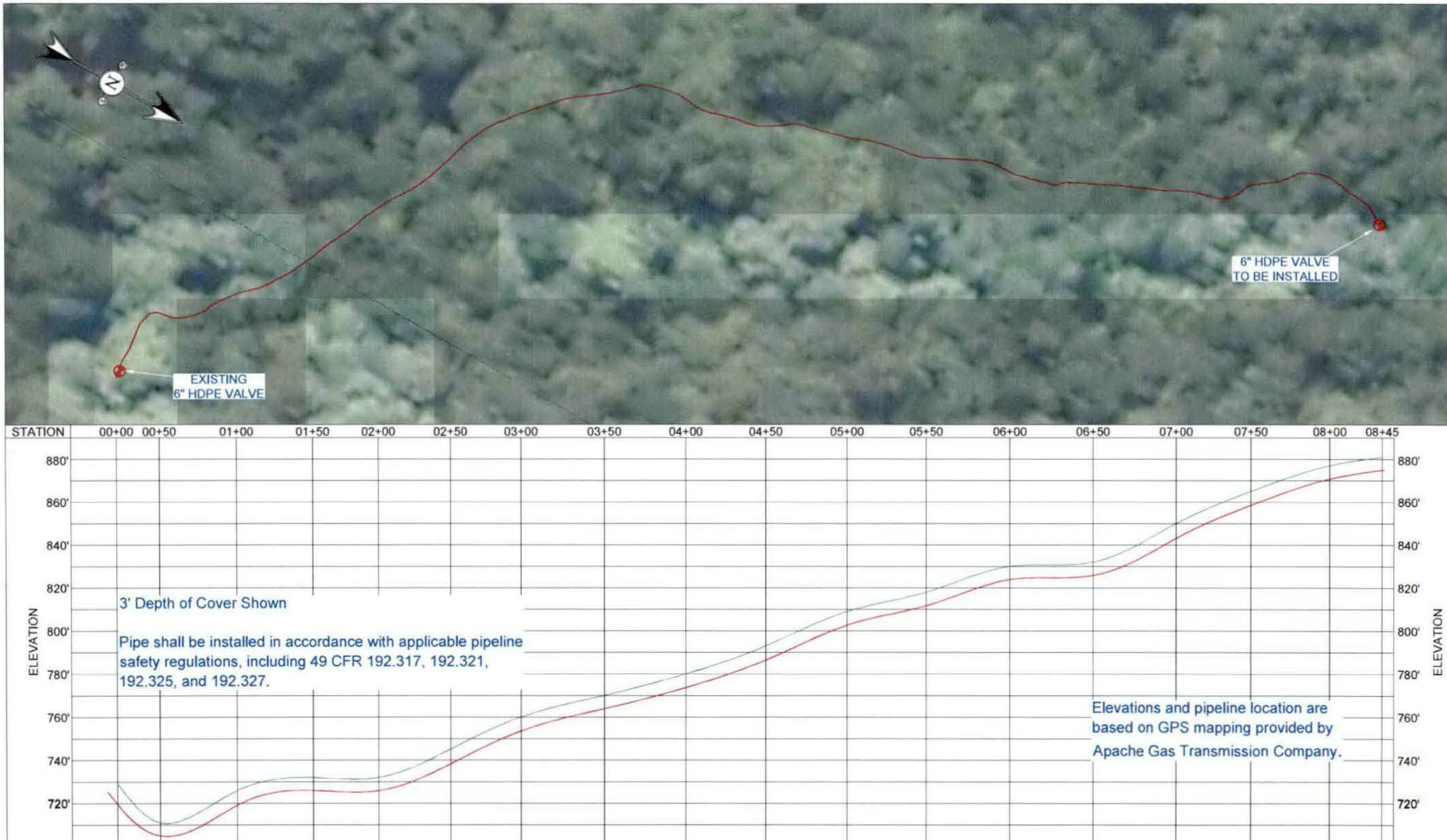
2017 REPLACEMENT PROJECT
APACHE GAS TRANSMISSION

USDI www.usdi.us

UTILITY SAFETY & DESIGN INC
P.O. BOX 727
SHELBYVILLE, KENTUCKY 40066
PHONE: 502-513-51272
www.usdi.us

CLIFF NORRIS SECTION

SHEET
PR-01



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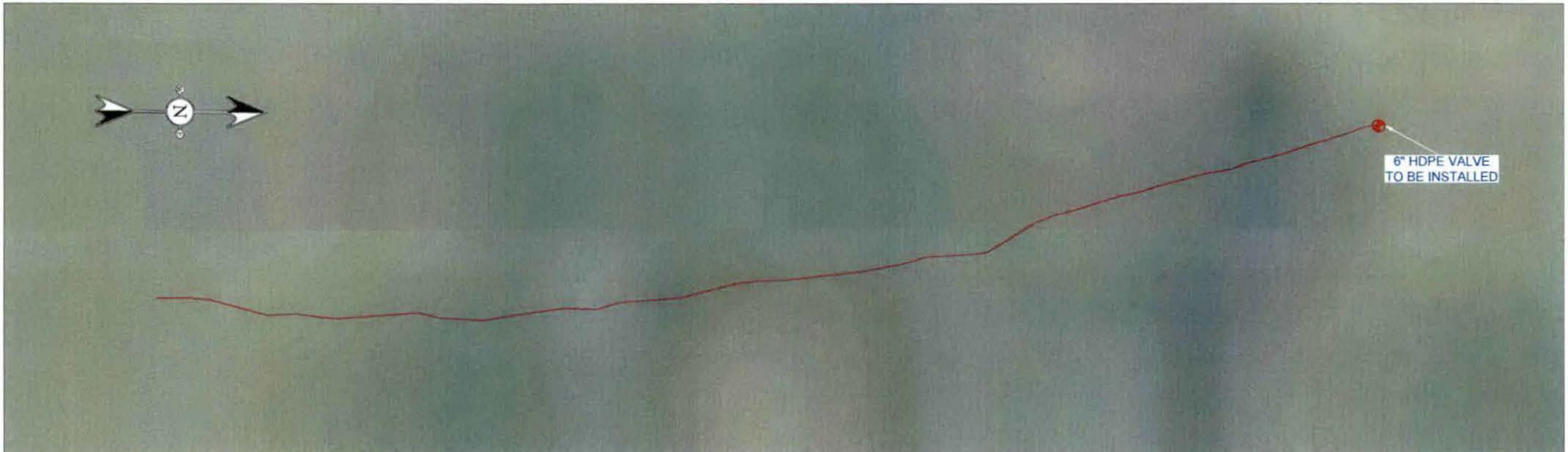
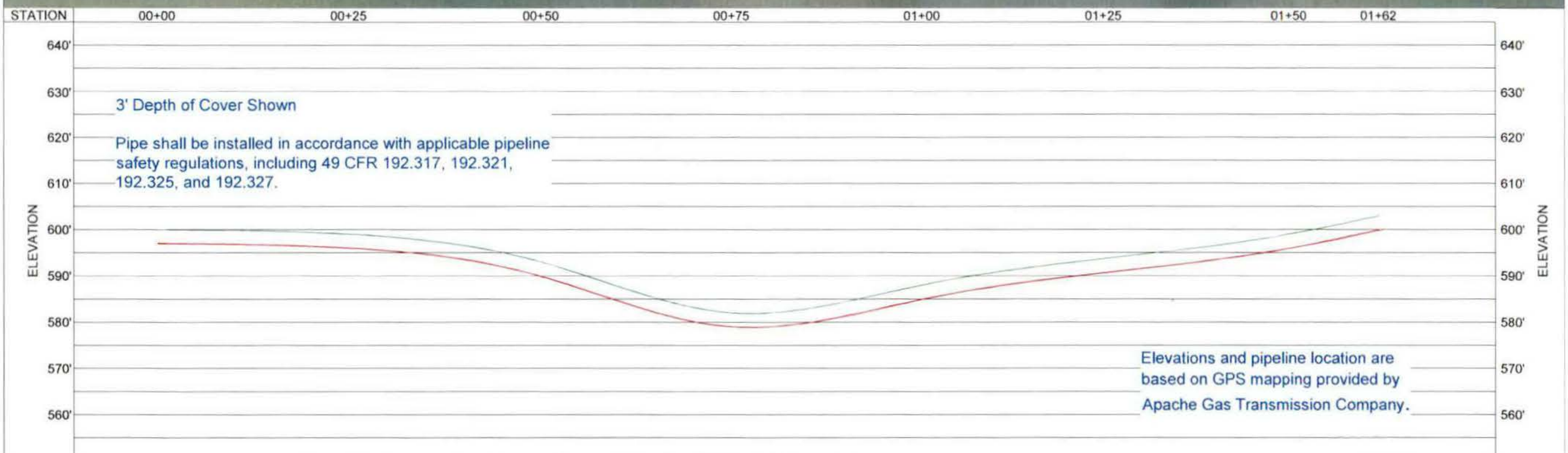
DOUG LEWIS
SECTION B

SHEET
PR-02





LEGEND:

PROPOSED 6" HDPE GAS PIPELINE

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ALLEN CREEK RD
DRAINAGE DITCH
SECTION

SHEET
PR-03

MAPS TO SCALE AND PDF VERSIONS ALSO FILED

Apache Gas Transmission
Natural Gas Pipeline Replacement
Project Specifications and Requirements

Prepared for

Apache Gas Transmission

April 2017

Prepared by

Jason Brangers, P.E.

USDI

Utility Safety and Design Incorporated
P.O. Box 727
Shelbyville, KY 40065

STATE OF KENTUCKY
JASON R. BRANGERS
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LICENSED
PROFESSIONAL ENGINEER

4-12-2017

Apache Gas Transmission Natural Gas Pipeline Replacement Project Specifications and Requirements

Prepared for

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April 2017

Prepared by

Jason Brangers, P.E.

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Table of Contents

Introduction

Apache Gas Transmission Company, Inc. (Apache Gas) is proposing to replace approximately 2,000 feet of exposed natural gas pipeline along three (3) sections of its existing transmission pipeline. The proposed pipe replacement is 6" HDPE and the installation method will be open trenching for the project. Apache Gas has received proposals for the installation of these in accordance with the specifications contained within this document as well as the project drawings.

Project Scope

The proposed pipeline replacement project will cover three sections of the Apache Gas transmission pipeline, which traverses Cumberland and Metcalf counties in southern Kentucky. The three sections along the pipeline are referred to as the "Cliff Norris Section", "Doug Lewis Section B", and "Allen Creek Road Drainage Ditch Section", and all are in Class 1 locations. The three sections are currently comprised of High Density Polyethylene (HDPE) pipe and will be replaced with 6" HDPE. The existing maximum allowable operating pressure (MAOP) of the three pipeline sections in question is 100 psig. The pipe and components utilized in the scope of this project must meet or exceed the requirements of the existing MAOP. The pipe is in need of replacement as they are located in rough terrain and steep grades, and the pipeline is currently exposed. The installation method will be open trench for the three pipeline sections and will occur in the existing Apache Gas right-of-way. There are no road or railroad crossings. Please see the project drawings for the locations, lengths, and additional details of the three sites.

807 KAR 5:001 Section 15(2)(a): Proposed Construction is Required by Public Convenience and Necessity

The Apache Gas transmission pipeline is served through an interconnect with Texas Eastern in Metcalf County, Kentucky. The Apache Gas transmission pipeline traverses approximately eighteen (18) miles and supplies natural gas to the Burkesville Gas Company, a local distribution company that serves residents, businesses, local government, hospitals, and schools in and around the city of Burkesville. Burkesville Gas receives all of its natural gas supply from the Apache Gas transmission pipeline. The replacement of these pipelines is critical for the integrity of the Apache Gas system as they are plastic and have been exposed for a period of time. Exposure of the PE pipeline sections threatens their integrity and leaves them vulnerable to damage from dig-ins, off-road vehicles, vandalism, and rocks, as wells as degradation due to UV exposure. The replacement of these pipelines is critical to the reliability of gas delivery to Burkesville Gas and its customers. The Application and supporting testimony provide further evidence that the proposed pipeline replacement program is required by public convenience and necessity.

Construction Schedule

Pending the approval of the Application and CPCN by the PSC and based on the contractors proposals to perform the required replacements, it is estimated that it will take approximately two (2) months after the contractors receive the notice to proceed for all of the requested replacements to be completed on the three identified sections.

807 KAR 5:001 Section 15(2)(b): Copies of Franchises or Permits

Apache Gas states that it does not have any franchises. Burkesville Gas Company states that it has previously filed with the Commission the applicable franchises from the proper public authorities.

807 KAR 5:001 Section 15(2)(c): Full Description of the Proposed Location of the Proposed Construction

Apache Gas is proposing to replace three sections of its natural gas transmission pipeline that are currently exposed. The proposed pipeline replacement project will cover the Cliff Norris Section, Doug Lewis Section B, and the Allen Creek Road Drainage Ditch Section, the locations of which are shown on the maps and drawings labeled as Exhibit D. More specifically, the approximate beginning and ending coordinates, along with the estimated length of each section is included in the table below:

SECTION	BEGIN		END		LENGTH
	LATITUDE	LONGITUDE	LATITUDE	LONGITUDE	FEET
CLIFF NORRIS	36° 49.60 N	85° 32.08 W	36° 49.61 N	85° 32.00 W	900
DOUG LEWIS SECTION B	36° 50.38 N	85° 26.67 W	36° 50.29 N	85° 26.59 W	750
ALLEN CREEK RD DRAINAGE DITCH	36° 49.38 N	85° 25.97 W	36° 49.37 N	85° 26.96 W	100

As there are no other identified transmission pipelines in this area and Apache Gas is simply replacing pipe, not expanding its system or service territory, the proposed construction will not compete with any existing public utilities, corporations, or persons.

Apache Gas has approximately 18 miles of transmission line that originates in Metcalf County at its interconnect with Texas Eastern. The transmission line traverses in a southerly and westerly direction, generally, through Metcalf County, into Cumberland County, and terminates near the city of Burkesville, where natural gas is delivered to Burkesville Gas Company, Inc. for distribution through its system. The Apache Gas system is comprised of some steel, but mostly polyethylene (PE) pipe and is routed through rural areas, including some steep slopes and wooded areas as well as open fields, and along various county and local roads. The PE pipeline was exposed several areas, as noted in the 2014 PSC pipeline safety inspection report. Apache Gas completed the repairs/replacement of two of the four areas noted in the inspection report (the Doug Lewis Section A and Doug Lewis Section B), along with another area known as the Spoon Branch Section. This left the Cliff Norris Section and Doug Lewis Section B to be addressed, both of which are in more rural, rocky areas that are more difficult to access to due to steeper grades and trees. Apache Gas is seeking approval in its CPCN Application to address these two sections through a pipeline replacement program and recovery mechanism, Rider PRP, due to the higher cost and expense of accessing and properly replacing these pipelines. Remediation of the Cliff Norris Section will result in the replacement of approximately 900 feet of 6" pipe with 6" HDPE pipe. Remediation of the Doug Lewis Section B will result in the replacement of approximately 750 feet of 3" pipe with 6" HDPE pipe. Apache Gas has also identified a third area, the Allen Creek Road Drainage Section, where a small section of pipeline is exposed and needs to be replaced. The Allen Creek Road Drainage Ditch Section is currently a 3" HDPE gas main that crosses a drainage area between two higher slopes. This area typically only has water during a rain, or shortly thereafter, and drains into Allen Creek. However, erosion has caused a short section of pipe to become exposed and should be replaced. Remediation of the Allen Creek Road Drainage Section will result in the replacement of approximately 100 feet of 3" pipe with 6" HDPE. Polyethylene (PE) pipe will be installed in an open cut trench with a properly prepared base. The pipe will be heat-fused together, when necessary, to obtain the required replacement lengths, installed in the trench, and properly backfilled with a suitable material. The pipeline will be inspected, constructed, installed, purged, pressure tested, and instated in accordance with the project specifications and applicable pipeline safety regulations. Valves will be installed at each of the three sections as well.

The replacement of these pipelines is critical for the integrity of the system as they are plastic and have been exposed for a period of time. Exposure of the PE pipeline sections threatens their integrity and leaves them vulnerable to damage from dig-ins, off-road vehicles, vandalism, and rocks, as wells as degradation due to UV exposure. Apache Gas is seeking to repair or replace the exposed natural gas pipeline sections under the Rider PRP, which provides for the recovery of costs not recovered in the existing rates, while improving the safety and integrity of the system. Exhibit D included with the Application shows the location of each of these three sections, along with the plan and profile drawings

807 KAR 5:001 Section 15(2)(d)(1): Maps Showing Proposed Route or Location of Construction

Maps of suitable scale showing the location or route of the proposed construction or extension are provided in portable document format (PDF) on the included electronic format, as well as paper copies, labeled as Exhibit D of the application. There are no "like facilities" owned by others in the proposed project areas. A review of PHMSAs National Pipeline Mapping System (NPMS) shows no other active natural gas transmission pipelines in Cumberland County and no other active intrastate natural gas transmission pipelines in southern Metcalf County. Therefore, no additional "like facilities" are located or shown on the included maps and drawings.

807 KAR 5:001 Section 15(2)(d)(2): Plans, Specifications, and Drawings

Plans, specifications, and drawings of the proposed plant, equipment, and facilities are included as Exhibit D and Exhibit E of the Application.

KRS 322.340: Signed, Sealed, and Dated Plans, Specifications, Drawings, and Reports

Signed, sealed and dated plans, specifications, drawings, plats, and reports for the proposed construction prepared by an engineer registered engineer are included as Exhibit D and Exhibit E of the Application.

Pipeline Safety Regulations and Project Requirements

These construction specifications and regulatory requirements are provided as a supplement to the project drawings produced by Utility Safety and Design, Inc. This plan should assist in providing the contractor, inspector, and regulatory bodies with clear guidelines to follow to ensure the pipeline replacement is performed in accordance with applicable pipeline safety regulations. All work performed on Apache Gas facilities under the scope of this project must be performed and conducted in accordance with applicable federal and state pipeline safety regulations and as outlined in the project drawings and the specifications below.

49 CFR 192 Subpart A

49 CFR 192 Subpart A prescribes the minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer continental Shelf Lands Act (43 (U.S.C. 1331). All work performed on Apache Gas facilities under the scope of this project must be performed and conducted in accordance with 49 CFR 192 and any other applicable pipeline safety regulations.

49 CFR 192 Subpart B - Materials

49 CFR 192 Subpart B prescribes the minimum requirements for the selection and qualification of pipe and components for use in pipelines. All materials and components utilized under the scope of this project must be in accordance with 49 CFR 192 Subpart B and any other applicable pipeline safety regulations.

§192.53 General

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;
(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and,
(c) Qualified in accordance with the applicable requirements of this subpart (49 CFR 192 Subpart B)

§192.59 Plastic Pipe

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

§192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D2513-87 (incorporated by reference, *see* §192.7);

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

49 CFR 192 Subpart C – Pipe Design

49 CFR 192 Subpart C prescribes the minimum requirements for the design of pipe. All pipe utilized under the scope of this project must be in accordance with 49 CFR 192 Subpart C and any other applicable pipeline safety regulations.

§192.103 General

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§192.121 Design of plastic pipe.

Subject to the limitations of §192.123, the design pressure for plastic pipe is determined by either of the following formulas:

$$P = 2S\frac{t}{(D-t)}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

<u>Design Pressure Calculation for Proposed Project Pipe</u>

S = 1,600 at 73^0 (see manufacturer specs)
SDR = 11
DF = 0.32
Therefore, Design Pressure Equals:
P = [2*1,600/(11-1)]*(0.32) = 102 psig

Where:

P = Design pressure, gauge, psig (kPa).

S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference, *see* §192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]

t = Specified wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

D F = 0.32 or

= 0.40 for PA-11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (i.e. thicker pipe wall).

§192.123 Design limitations for plastic pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below −20 °F (−20 °C), or −40 °F (−40 °C) if all pipe and pipeline components whose operating temperature will be below −29 °C (−20 °F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under §192.121 is determined.

(ii) For reinforced thermosetting plastic pipe, 150 °F (66 °C).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters).	Minimum wall thickness inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a polyethylene (PE) pipe with the designation code as specified within ASTM D2513-09a (incorporated by reference, *see* §192.7);

(3) The pipe size is nominal pipe size (IPS) 12 or less; and

(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 200 psig (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR-11 or greater (*i.e.*, thicker pipe wall).

49 CFR 192 Subpart D – Design of Pipeline Components

49 CFR 192 Subpart D prescribes the minimum requirements for the design and installation of pipeline components and facilities. All pipeline components utilized under the scope of this project must be in accordance with 49 CFR 192 Subpart D and any other applicable pipeline safety regulations.

§192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

§192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, *see* §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

§192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within $2\frac{1}{2}$ miles (4 kilometers)of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within $7\frac{1}{2}$ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

The proposed project is contained within Class 1 locations, therefore, 192.179(a)(4) applies.

§192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* §192.7).
(b) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a for polyethylene plastic materials.

§192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

49 CFR 192 Subpart F – Joining of Materials Other Than by Welding

49 CFR 192 Subpart F prescribes the minimum requirements for joining materials in pipelines, other than by welding. All joining of materials, other than by welding, performed under the scope of this project must be in accordance with 49 CFR 192 Subpart F and any other applicable pipeline safety regulations.

§192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.
(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.
(c) Each joint must be inspected to insure compliance with this subpart.

§192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.
(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.
(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* §192.7).
(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

For the proposed project, the pipe shall be heat-fused pursuant to the above mentioned regulations and in accordance with pipe and equipment manufacturer specifications (see "Heat Fusion Joining Procedures and Qualification Guide" at the end of this report). Electrofusion may be utilized, but only upon approval by Apache Gas Transmission Company's Pipeline Project Representative.

§192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a (incorporated by reference, *see* §192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained

Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference, *see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

§192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

§192.287 Plastic pipe: Inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

49 CFR 192 Subpart G – General Construction Requirements for Transmission Lines and Mains

49 CFR 192 Subpart G prescribes the minimum requirements for constructing transmission lines and mains. All construction conducted under the scope of this project must be in accordance with 49 CFR 192 Subpart G and any other applicable pipeline safety regulations.

§192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

§192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

§192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

For the proposed project, all of the pipeline sections are "onshore", therefore, 192.319(c) does not apply. The contractor shall comply with 192.319(b) to ensure the pipeline is properly supported and appropriate and suitable backfill material is utilized. Bedding may be necessary to bring the trench bottom to the required pipe grade, level out any irregularities, and ensure uniform support along the pipe length. The backfill shall provide proper support, limiting flexible and lateral pipe deformation, distribute overhead loads, and isolate the pipe from any adverse effects of the final backfill layer. The final backfill layer should be free of large rocks, frozen clods, construction debris and stones.

§192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in §192.123.

§192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).

The contractor shall ensure a minimum of 12 inches of separation/clearance between the transmission pipeline any other underground structure not associated with the pipeline.

§192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	**Normal soil**	**Consolidated rock**
	Inches (Millimeters)	Inches (Millimeters)
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §192.3, must be installed in accordance with §192.612(b)(3).

Due to the terrain and steep slope of the sections involved in this project and potential for erosion, the contractor shall install the pipe with a minimum of 30" of cover. If the pipeline is in consolidated rock and achieving 30" of cover is not possible, the contractor shall install the pipe as deep as practicable, but with no less than 18" of cover.

49 CFR 192 Subpart J – Test Requirements

49 CFR 192 Subpart J prescribes the minimum leak-test and strength-test requirements for pipelines. All leak and strength tests conducted under the scope of this project must be in accordance with 49 CFR 192 Subpart J and any other applicable pipeline safety regulations.

§192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

(e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

§192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

The pipeline and associated appurtenances shall be pressure tested in accordance with 49 CFR 192.513 to ensure discovery of all potentially hazardous leaks in the segment being tested. The test pressure must be at least 150 percent of the maximum operating pressure (100 psig), but not more than three times the design pressure determined under 49 CFR 192.121 (102 psig). The contractor shall test the pipeline at a pressure of at least 150 psig, but not more than 306 psig. The tie-in fuses shall be leak tested at operating pressure.

§192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§192.517 Records.

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:

(1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(2) Test medium used.

(3) Test pressure.

(4) Test duration.

(5) Pressure recording charts, or other record of pressure readings.

(6) Elevation variations, whenever significant for the particular test.

(7) Leaks and failures noted and their disposition.

(b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

The contractor shall document and record the pressure in accordance with 192.517. All documentation shall be provided to Apache Gas for its inclusion in its compliance records.

49 CFR 192 Subpart L – Operations

49 CFR 192 Subpart L prescribes the minimum requirements for the operation of pipeline facilities. Operation of the pipeline under the scope of this project must be in accordance with 49 CFR 192 Subpart L and any other applicable pipeline safety regulations.

§192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under §192.605.

(c) The Associate Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is $12^3/_4$ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors[1], segment—		
Class location	**Installed before (Nov. 12, 1970)**	**Installed after (Nov. 11, 1970)**	**Converted under §192.14**
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5

4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	**Pressure date**	**Test date**
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

§192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

The contractor shall comply with 192.629 when performing a purge of the pipeline. Records shall be made and provided to Apache Gas for inclusion in its compliance documentation.

49 CFR 192 Subpart M – Maintenance

49 CFR 192 Subpart M prescribes the minimum requirements for maintenance of pipeline facilities. Maintenance performed on the pipeline under the scope of this project must be in accordance with 49 CFR 192 Subpart M and any other applicable pipeline safety regulations.

§192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under §192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with $^1/_4$inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

§192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

§192.719 Transmission lines: Testing of repairs.

(a) *Testing of replacement pipe.* If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§192.713, 192.715, and 192.717 must be examined in accordance with §192.241.

§192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

49 CFR 192 Subpart N – Qualification of Pipeline Personnel

49 CFR 192 Subpart N prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. A covered task is an activity, identified by the operator, that:

(1) Is performed on a pipeline facility;

(2) Is an operations or maintenance task;

(3) Is performed as a requirement of this part; and

(4) Affects the operation or integrity of the pipeline.

Personnel performing covered tasks on the pipeline under the scope of this project must be operator qualified in accordance with 49 CFR 192 Subpart N and any other applicable pipeline safety regulations and must be able to appropriately recognize and react to abnormal operating conditions (AOCs). An AOC is a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) Indicate a condition exceeding design limits; or

(b) Result in a hazard(s) to persons, property, or the environment

§192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;

(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to *InformationResourcesManager@dot.gov,* or by mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, New Jersey Avenue SE., Washington, DC 20590.

§192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

(1) Identification of qualified individual(s);

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification; and

(4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§192.809 General.

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

Personnel performing covered tasks shall meet the requirements of 49 CFT 192 Subpart N. The contractor shall provide a copy the following:

- Operator Qualification Plan
- List of individuals performing a covered task(s) as part of this project
- Evaluations of individuals performing covered tasks on this facility
- Fusion qualifications and certificates for individuals performing such tasks

- Drug and Alcohol plan and proof of participation

Personnel performing covered tasks on the pipeline under the scope of this project must be operator qualified in accordance with 49 CFR 192 Subpart N and any other applicable pipeline safety regulations and must be able to appropriately recognize and react to abnormal operating conditions (AOCs). An AOC is a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) Indicate a condition exceeding design limits; or
(b) Result in a hazard(s) to persons, property, or the environment

49 CFR 192 Appendix B – Qualification of Pipe

49 CFR 192 Appendix B lists pipe specifications and requirements for pipe that is approved for use under 49 CFR 192, including, but not limited to, the following plastic/polyethylene pipe:

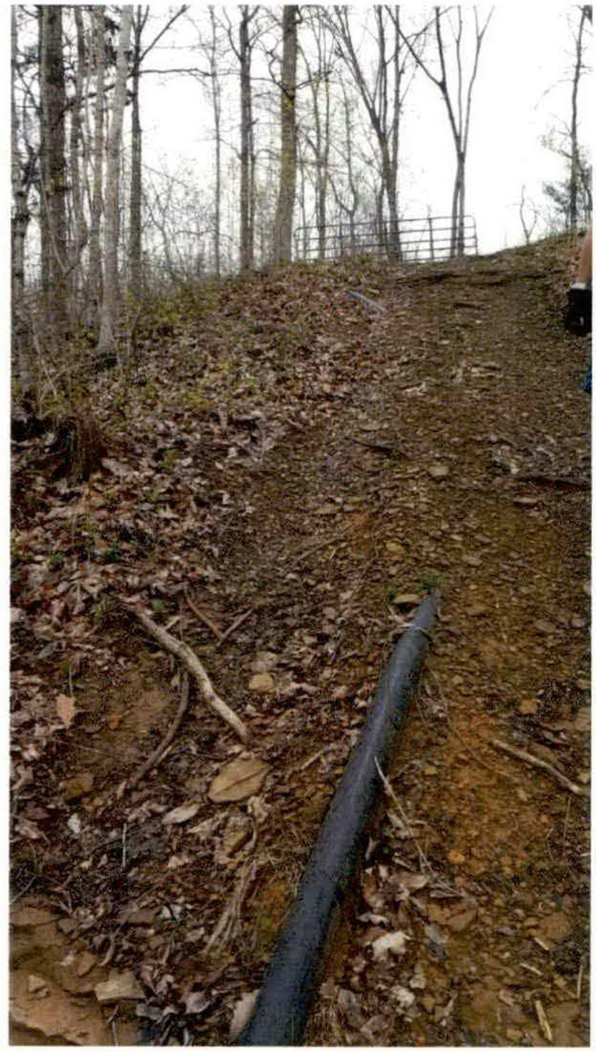
ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (incorporated by reference, *see* §192.7) .

ASTM D2513-09a—Polyethylene thermoplastic pipe and tubing, "Standard Specification for Polyethylene (PE) gas Pressure Pipe, Tubing, and Fittings", (incorporated by reference, *see* §192.7) .

ASTM D2517—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* §192.7).

CLIFF NORRIS SECTION

DOUG LEWIS SECTION B



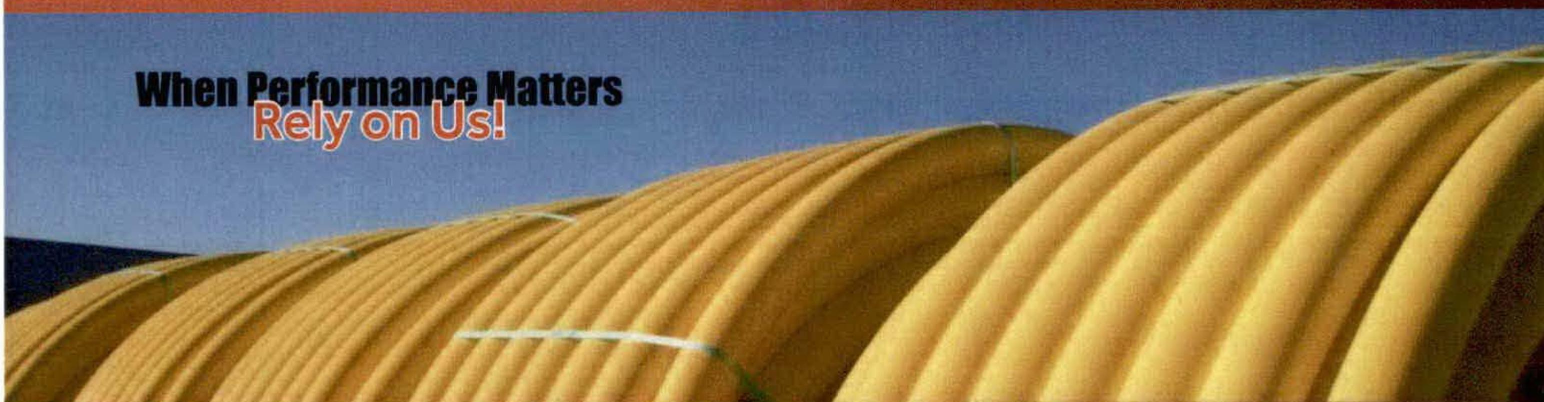
ALLEN CREEK ROAD DRAINAGE DITCH SECTION

HDPE PIPE AND VALVE SPECIFICATIONS AND PROCEDURES

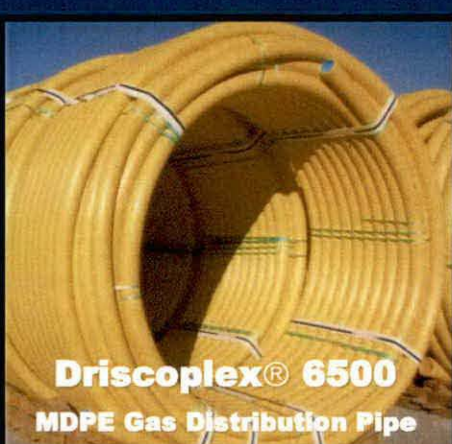
PIPE AND VALVE SPECIFICATIONS

PIPE MATERIAL:	HIGH DENSITY POLYETHYLENE (HDPE)
PIPE DIAMETER:	SIX INCH (6")
STANDARD DIMENSION RATIO (SDR):	ELEVEN (11)
MATERIAL DESIGNATION:	PE3408/PE4710
QUALIFICATION OF PIPE STANDARD:	ASTM D2513
HYDROSTATIC DESIGN BASIS (73°):	1,600 PSI
MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP):	100 PSIG
NORMAL OPERATING PRESSURE:	70-80 PSIG
MAXIMUM DESIGN PRESSURE PURSUANT TO 192.121:	102 PSIG
VALVE MATERIAL:	HIGH DENSITY POLYETHYLENE (HDPE)
VALVE SIZE:	SIX INCH (6")
STANDARD DIMENSION RATIO (SDR):	ELEVEN (11)
MATERIAL DESIGNATION:	PE3408/PE4710

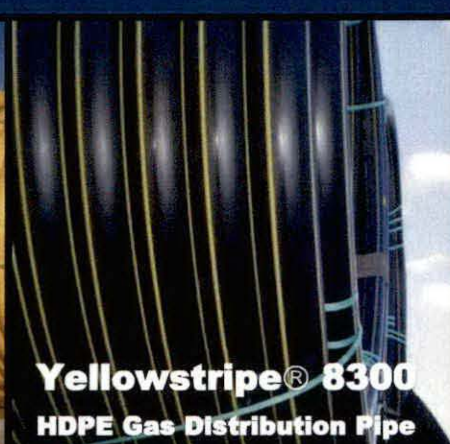
PERFORMANCE PIPE
A DIVISION OF CHEVRON PHILLIPS CHEMICAL COMPANY LP



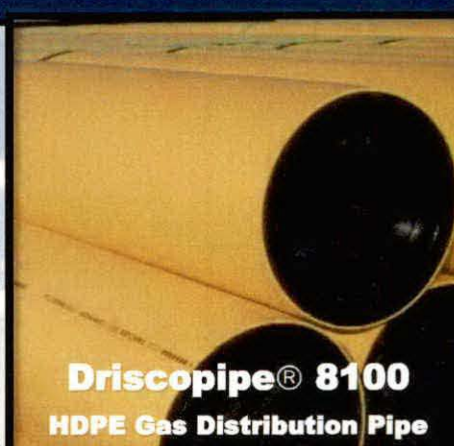
PERFORMANCE PIPE GAS DISTRIBUTION BROCHURE



Driscoplex® 6500
MDPE Gas Distribution Pipe



Yellowstripe® 8300
HDPE Gas Distribution Pipe



Driscopipe® 8100
HDPE Gas Distribution Pipe

Performance Pipe

Performance Pipe is a name you can trust in gas distribution piping. We specialize in natural gas distribution, liquid propane gas (LPG), propane gas distribution, and yard gas products and fittings.

With more than fifty years of polyethylene pipe manufacturing experience, Performance Pipe has nine ISO 9001 certified manufacturing facilities strategically located across the United States.

The unmatched quality and performance of Performance Pipe polyethylene piping products is further enhanced and strengthened by more than five decades of quality polyolefin plastic resin production from our parent company Chevron Phillips Chemical Company LP.

As active members of the American Gas Association, ASTM International, Gas Piping Technology Committee, Plastics Pipe Institute, American Society of Mechanical Engineers, and American Petroleum Institute, we provide technical expertise and service to these organizations on an ongoing basis.

When you select Performance Pipe gas pipe and fittings, in addition to receiving quality products, you also gain access to our team of experts for technical support and assistance. Topics range from assistance in product applications and capabilities to installation and handling to testing and operating procedures. We are here to help.
Our territory sales teams are dedicated to the gas distribution industry and to the service of Performance Pipe's gas distribution product customers.

Products

Performance Pipe's gas piping products are the material of choice for premium medium and high density natural gas distribution, LPG, propane gas and yard gas piping systems. Performance Pipe's products are produced to meet or exceed the manufacturing and material requirements of the latest edition of ASTM D2513 *Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings*, or applicable international standards. The pipes meet the requirements of ANSI/NFPA 58 *Standard for the Storage and Handling of Liquefied Petroleum Gases.*

Performance Pipe offers the following gas distribution products:

Driscoplex® 6500 MDPE Gas Distribution Pipe These medium density polyethylene (MDPE) PE2708 (PE2406) pipes and fittings are used primarily in pressure-rated gas distribution systems. The product is also suitable for LPG, propane, yard gas and most after-meter applications. The product is a solid yellow medium density pipe that meets ASTM D3350 Cell Classification of PE234373E and APWA/ULCC Color Code Standards.

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Yellowstripe® 8300 HDPE Gas Distribution Pipe These high density polyethylene (HDPE) PE4710/PE100 (PE3408) pipes and fittings are used primarily in pressure rated gas distribution systems. The product is black pipe with four equidistant yellow stripes. The Yellowstripe® 8300 pipe series meets APWA/ULCC Color Code Standards and has an ASTM D3350 Cell Classification of PE445574C when using HDB or PE445576C using MRS.

Driscopipe® 8100 HDPE Gas Distribution Pipe These high density polyethylene (HDPE) PE4710/PE100 (PE3408) pipes and fittings are also primarily used in pressure rated gas distribution applications. The Driscopipe® 8100 pipe series is a black pipe with a co-extruded yellow-shell that complies with the APWA/ULCC Color Code Standards. The pipe has an ASTM D3350 Cell Classification of PE445574C when using HDB or PE445576C using MRS. The yellow shell helps reflect solar heat, enabling retention of higher strength ambient temperature properties. It also provides improved ability to detect damages and scratches.

Fittings

Performance Pipe manufactures medium density and high density molded butt, socket, and saddle fusion fittings.

Quality

Performance Pipe's polyethylene piping products for gas are unmatched in quality and performance. In addition to meeting the manufacturing and quality requirements of ASTM D2513 *Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings,*. Performance Pipe's gas products also meet our own internal quality assurance (QA) and quality control (QC) requirements. These internal QA/QC requirements meet or exceed those required by industry standards. Each product line is continuously monitored throughout the manufacturing cycle to ensure that the product adheres to all internal quality control specifications and the manufacturing standard. All nine of Performance Pipe's manufacturing facilities are certified in accordance with the latest edition of ISO 9001. Individual plant certificates of conformance to ISO 9001 are available upon request.

Sizes

Performance Pipe manufactures its Driscoplex® 6500 pipe product through 12" IPS sizes. For larger diameter gas applications (8" though 24") we recommend our high density polyethylene pipes Yellowstripe® 8300 pipe and Driscopipe® 8100 pipe. Both products are available in 1/2" through 24" (16 mm through 630 mm) outside-diameter-controlled polyethylene pipe and tubing sizes. Specific sizes of pipe and fittings available for each product can be found on Performance Pipe's website at www.PerformancePipe.com.

Available Certifications

Specific sizes of Driscoplex® 6500 (MDPE) pipe, Yellowstripe® 8300 (HDPE) pipe and Driscopipe® 8100 (HDPE) pipe and fittings are available with CSA (Canadian Gas Association) certification. Many sizes of Driscoplex® 6500 pipe are available with UPC (Uniform Plumbing Code) certification by IAPMO (International Association of Plumbing and Mechanical Officials) for yard gas piping, LPG and other after-meter applications.

Outdoor Storage

Performance Pipe polyethylene gas distribution piping products are protected from UV effects and outdoor exposure to ensure pipe performance requirements are maintained.

Yellow pipes, such as Driscopipe® 8100 HDPE gas distribution pipe and Driscoplex® 6500 MDPE gas distribution pipe, are protected against outdoor exposure through additive formulations and are defined as Code E materials in accordance with ASTM D3350. Yellowstripe® 8300 HDPE gas distribution pipe is defined as a Code C material and as such contains a minimum of 2-3 percent carbon black.

Accelerated laboratory weathering tests were conducted on the formulations that predict the yellow pipe materials are sufficiently protected to provide a service life of at least four years in outdoor exposure conditions.

Black pipe material weathering tests indicate an unlimited outdoor storage potential. The actual test data confirmed that there is no measurable change in pipe performance properties after four years of outdoor exposure for Code E materials and no measurable change for Code C materials after more than 40 years.

Based on the tests conducted, Performance Pipe provides the following specific unprotected outdoor storage recommendations for Performance Pipe's gas distribution piping products.

- Driscoplex® 6500 pipe 3 years
- Driscopipe® 8100 pipe 3 years
- Yellowstripe® 8300 pipe 10 years

Cautions

Polyethylene piping has been safely used in thousands of applications. However, there are general precautions that should be observed when using any product. In this respect, polyethylene piping is no different. Below is a list of some of the precautions that should be observed when using Performance Pipe's gas pipe and fittings.

- **Fusion**

  During the heat fusion process, equipment and products can reach temperatures in excess of 450°F (231°C). Caution should be taken to prevent burns.

  Do not bend pipes into alignment against open butt fusion machine clamps. The pipe may spring out and cause injury or damage.

  Performance Pipe polyethylene piping products cannot be joined with adhesives or solvent cement. Pipe-thread joining and joining by hot air (gas) welding or extrusion welding techniques are not recommended for pressure service.

- **Static Electricity**

  High static electricity charges can develop on polyethylene piping products, especially during squeeze-off, when repairing a leak, purging, making a connection, etc.

  Where a flammable gas atmosphere and static electric charges may be present, observe all company (pipeline operator, utility, contractor, etc.) safety procedures for controlling and discharging static electricity and all requirements for personal protection. See website for: Performance Pipe Technical Note *Polyethylene Pipe Squeeze Off; PP 801-TN.*

- **Weight, Unloading and Handling**

  Although polyethylene pipe is not as heavy as some other piping products, significant weight may be involved. Care should be used when handling and working around polyethylene pipe. Improper handling or abuse may cause damage to piping, compromise system quality or performance, or cause personal injury. Observe the safe handling instructions provided by the delivery driver. See website for: *Pipe Loading/Unloading-Truck Driver Safety Video.*

- **Coils**

  Coiled PE pipe is restrained with strapping to contain the spring-like energy retained within the coil. Cutting or breaking strapping can result in an uncontrolled release. Take all necessary safety precautions and use appropriate equipment. Observe the safe handling instructions provided by the delivery driver.

Leak Testing

When testing is required, fuel gas distribution systems should be tested in accordance with applicable codes and regulations and distribution system operator procedures. Observe all safety measures, restrain pipe against movement in the event of catastrophic failure, and observe limitations of temperature, test pressure, test duration, and procedures for making repairs.

Protection against Shear and Bending Loads

Measures such as properly placed, compacted backfill, protective sleeves, and structural support are sometimes necessary to protect plastic pipe against shear and bending loads.

For additional installation information see ASTM D-2774, *Underground Installation of Thermoplastic Pressure Piping.*

Liquid Hydrocarbon Permeation

PE piping that has been in service conveying fuel gases that include heavier hydrocarbons can sometimes exhibit a bubbly appearance when melted for heat fusion. This bubbling is the result of the rapid expansion (by heat) and passage of heavier, adsorbed hydrocarbon gases through the heated and molten polyethylene material. Studies* have shown that propane concentrations under 0.2% is sufficient to sometimes show some bubbling, but is not high enough to effect any significant degradation in strength of the pipe or fusion joint. However, since there currently are no field tests to readily determine the amount of adsorbed hydrocarbons in PE pipe and their potential effect on the fusion joint, the heat fusion process should be abandoned and mechanical connections should be used if bubbles are encountered during a heat fusion process.

(*)S.M. Pimputkar, J.A. Stets, and M.L. Mamoun, "Examination of Field Failures", Sixteenth International Plastics Pipe Symposium, New Orleans, Louisiana, November 1999.

Locating

Most polyethylene materials are not detectable with standard magnetic locating equipment. When installing PE piping, a method or methods for future pipeline detection should be considered. Gas utilities in the area should always be contacted before the start of any underground installation work such as excavation, trenching, directional boring, etc.

Joining

- D.O.T. Regulations require that each joint in a gas piping system must be made in accordance with written procedures that have been proved by test or experience to produce strong gastight joints (49 CFR, Part 192, §192.273(b)).
- D.O.T. Regulations require that written procedures for butt fusion, saddle fusion, and socket fusion joining of polyethylene gas piping must be qualified before use by subjecting specimen joints to required test procedures (CFR 49, Part 192, §192.283(a)).
- D.O.T. Regulations require that all persons who make joints in polyethylene gas piping must be qualified under the operator's written procedures (CFR 49, Part 192, & §192.285(a)).
- D.O.T. Regulations require that the gas system operator must ensure that all persons who make or inspect joints are qualified (CFR 49, Part 192, §192.285(d) & §192.287).

Performance Pipe recommends using Performance Pipe's Fusion Joining Procedures Bulletin *PP-750 Heat Fusion Joining Procedures and Qualification Guide* when making heat fusion joints with our gas piping products. When PP-750 is used to join Performance Pipe polyethylene gas pipe and fittings, Performance Pipe fusion joining procedures are qualified in accordance with U.S. Department of Transportation Regulations. A copy of PP-750 may be obtained from our website at: www.performancepipe.com

Other qualified procedures used for butt and saddle fusion of polyethylene gas piping products are the Plastic Pipe Institute's, PPI TR-33/2006 *Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe* and PPI TR-41 *Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping.*

Squeeze-Off

Squeeze-off is used to control flow in PE pipe by flattening the pipe between parallel bars. Squeeze-off is used for routine and emergency situations. ***Do not squeeze-off more than once at the same point on the pipe.*** For repeated flow control, throttling, or partial flow restriction, install a valve or an appropriate flow control device.

Complete flow stoppage will not occur in all cases. For larger pipes, particularly at higher pressures, some seepage is likely. If seepage is not permissible, the pipe should be vented in between two squeeze-offs.

Use squeeze-off procedures meeting ASTM F1041 and tools meeting ASTM F1563 with Performance Pipe polyethylene pipes. The combination of pipe, tool, and squeeze-off procedures should be qualified in accordance with ASTM F1734. Correct tool closure stops and closing and opening rates are key elements to squeezing-off without damaging the pipe. Tool closure stops must be correct for the pipe size and wall thickness (SDR). It is necessary to close slowly and release slowly, with slow release being more important.

See Performance Pipe Technical Note *PP-801 Squeeze-Off* on our website at: www.performancepipe.com.

Performance Characteristics

Cell Classification

ASTM D3350 *Standard Specification for Polyethylene Plastics Pipe and Fittings Materials* standard cell classification covers the identification of polyethylene materials for pipe and fittings according to a cell classification system. Performance Pipe's gas piping products are listed below.

Table 1: Cell Classifications

Performance Pipe Product Series	Material Designation Code		ASTM D3350 Cell Classification
	Present	Past	
Driscoplex® 6500 Pipe (MDPE)	PE2708	(PE2406)	234373E
Driscopipe® 8100 Pipe (HDPE)	PE4710-PE100	(PE3408)	445574C (445576C*)
Yellowstripe® 8300 Pipe (HDPE)	PE4710-PE100	(PE3408)	445574C (445576C*)

* When using the Minimum Required Strength (MRS) classification.

Long-Term Strength (HDB)

Performance Pipe's polyethylene piping products for gas distribution are listed with the Plastics Pipe Institute (PPI) and have PPI recommended Hydrostatic Design Basis (HDB) ratings as follows:

Table 2: Hydrostatic Design Basis

Performance Pipe Product Series	Hydrostatic Design Basis (HDB) 73°F (23°C)	Hydrostatic Design Basis (HDB) 140°F (60°C)
Driscoplex® 6500 Pipe (MDPE)	1250 psi (8.62 MPa)	1000 psi (6.89 MPa)
Driscopipe® 8100 Pipe (HDPE)	1600 psi (11.03 MPa)	1000 psi (6.89 MPa)
Yellowstripe® 8300 Pipe (HDPE)	1600 psi (11.03 MPa)	1000 psi (6.89 MPa)

HDB by Temperature Interpolation

Elevated temperature properties can be used to determine product capabilities for applications where products will be exposed to elevated temperatures. The Hydrostatic Design Stress for polyethylene is established by testing at 73°F. As with all thermoplastics, when operating temperature increases, pressure capacity decreases.

When determining HDB values, use the interpolation protocol of PPI TR-3-2006 D.2 *Policy for Determining Long-Term Strength (LTHS) By Temperature Interpolation*.
The policy states that, for thermoplastic pipe that is going to be installed at a service temperature greater than 73°F and less than that at which the next HDB has been established, the HDB at the anticipated service temperature can be determined by interpolation.

Table 3: HDB in PSI by Temperature Interpolation

Service Temperature (°F)	73 Determined	100 interpolated	110 interpolated	120 interpolated	130 interpolated	140 Determined
Driscoplex® 6500 Pipe (MDPE)	1250	1250	1000	1000	1000	1000
Driscopipe® 8100 Pipe (HDPE)	1600	1250	1250	1000	1000	1000
Yellowstripe® 8300 Pipe (HDPE)	1600	1250	1250	1000	1000	1000

Slow Crack Growth (SCG) Resistance

Resistance to slow crack growth is a critical performance requirement because long-term stress can cause cracks to grow slowly through polyethylene pipe resin material. Polyethylene gas pipe is under long-term stress from internal pressure and earthloading. Thus gas distribution service requires materials that have superior long-term resistance to stress cracking and slow crack growth (SCG).

Resistance to slow crack growth is measured using ASTM F1473 *Standard Test Method for Notch Tensile Test to Measure the Resistance to Slow Crack Growth of Polyethylene Pipes and Resins*. Studies* have shown that a 150 hour PENT test could be compared to several centuries of leak free performance in the field.

(* PENT Quality Control Test for PE Gas Pipes and Resins: Dr. Norman Brown and X. Lu; Presented at the 12th Plastic Fuel Gas Pipe Symposium, Sept. 24-26, 1991.)

Table 4: Typical PENT Values

Performance Pipe Product Series	PENT, hours (ASTM F1473)
Driscoplex® 6500 Pipe (MDPE)	>2,000
Driscopipe® 8100 Pipe (HDPE)	>2,000
Yellowstripe® 8300 Pipe (HDPE)	>2,000

ASTM D2513 requires that all PE materials used in gas distribution service meet a minimum of at least 100 hours for two tests before failure when tested per ASTM F1473. Performance Pipe's gas products are tested to over twenty times these minimum testing requirements.

Recent research* has revealed various failure modes for pipes under long term PENT testing. Some doubt has been cast on the correlation between brittle and ductile failure in pressurized pipes and the laboratory established PENT failure times. The research lends credibility to limiting testing times of the PENT test.

(*) R.K Krishnaswamy, Asish M. Sukhadia and Mark J. Lamborn "Is PENT a True Indicator of PE Pipe Slow Crack Growth Resistance", Performance Pipe Technical Note PP-818-TN, Chevron Phillips Chemical Company, LP.

Over 9,245 production lots of gas pipe manufactured from Performance Pipe PE2708 (PE2406) piping material have been tested against ASTM F1248, *Standard Test Method for Determination of Environmental Stress Crack Resistance (ESCR) of Polyethylene Pipe*. These production lots have amassed a performance history that cumulatively represents over 105 years of testing without failure.

Rapid Crack Propagation

When a pressurized polyethylene pipe is subjected to an instantaneous and intense impact, a pre-existing or consequently initiated crack or flaw can propagate axially at extremely high speeds. Such an impact is referred to as Rapid Crack Propagation, or RCP. It is a property inherent in fracture mechanics of many pipe materials, including polyethylene. Similarly, Rapid Crack Arrest (RCA) is a fast fracture property of the pipe material that arrests the travel of the crack after initiation or before RCP can occur.

While RCP occurrences in PE pipes are extremely rare, the consequences can be significant. Because of the catastrophic nature of a potential RCP event, pipe producers have begun to design pipes and applications such that RCP may be avoided in most circumstances. This has led to the development of several tests, of which the Full-Scale (FS) and Small-Scale Steady State (S4) tests are most relevant.

<u>Full Scale Test (FST) ISO 13478</u>

Polyethylene pipes that are approximately 40 times the diameter in length are pressurized at low temperatures, and failure is initiated through blunt force impact with a striker at one end to initiate a crack. The critical pressure and temperature are directly determined. There are no Full-Scale Test facilities in the United States.

<u>Small-Scale Steady State (S4) ISO 13477 and ASTM F1589</u>

The S4 test pipe specimens are typically a minimum of seven times the diameter in length. Specimens are conditioned at the test temperature externally, and then moved to the S4 test rig where they are sealed at both ends and pressurized with air. A sharp chisel-edged striker impacts the pipe at one end to initiate a fast-running crack. A containment cage around the specimen and a series of baffles constrain the outside diameter of the pipe. The results are correlated to the critical temperature and pressure.

Performance Pipe's gas piping products are all tested to ISO 13477 Small-Scale Steady State with exceptional RCP resistance.

ASTM Test Values

The charts below show material physical properties, ASTM test methods for the property, and nominal values for Performance Pipe materials used for gas pipe. (Note - Per ASTM D 748, the brittleness temperature is less than <-180°F (<-118°C), therefore, Performance Pipe's Yellowstripe® 8300 pipe, Driscopipe® 8100 pipe and Driscoplex® 6500 pipe series may be used at operating temperatures down to or below <- 40°F (<-40°C)). Typical physical properties for each pipe are included below.

Yellowstripe® 8300 HDPE Gas Distribution Pipe PE4710-PE100 / (PE3408) Typical Physical Property Pipe Data Sheet			
Property	**Unit**	**Test Procedure**	**Typical Value**
Material Designation	--	**PPI TR-4**	**PE4710 PE100**
Cell Classification	--	**ASTM D3350**	**445574C 445576C**
Pipe Properties			
Density	gms / cm^3	ASTM D1505	0.961 (black)
Melt Index (MI) Condition 190/2.16	gms / 10 minutes	ASTM D1238	0.08
Melt Index (HLMI) Condition 190/21.6	gms / 10 minutes	ASTM D1238	7.5
Hydrostatic Design Basis, (73°F)	psi	ASTM D2837	1,600
Hydrostatic Design Basis, (140°F)	psi	ASTM D2837	1,000
Minimum Required Strength	Mpa (psi)	ISO 9080	>10 (>1450)
Rapid Crack Propagation Critical Pressure (Pc), 0°C (32°F)(1)	Bar (psi)	ISO 13477	>12 bar (>174)
Color; UV Stabilizer [C]	%	ASTM D3350	Min. 2% Carbon Black UV stabilized 10 years
Pipe Test Category	---	ASTM D2513	CEE
Material Properties			
Flexural Modulus @2% strain	psi	ASTM D790	>150,000
Tensile Strength at Yield	psi	ASTM D638 (Type IV)	>3,500
Elongation at Break 2 in/min., Type IV bar	%	ASTM D638	>800
Hardness	Shore D	ASTM D2240	65
PENT	hrs	ASTM F1473	>2,000
Manufactured to ASTM D2513 for pipe. Fittings comply with ASTM D2513 and ASTM D3261.			
Thermal Properties			
Vicat Softening Temperature	°F	ASTM D1525	255
Brittleness Temperature	°F	ASTM D746	-180
Thermal Expansion	in / in / °F	ASTM D696	1.0×10^{-4}

(1) Determination made using Small-Scale Steady state. Pc calculated in accordance with ISO 13477

(2) NOTICE: This data sheet provides typical physical property information for polyethylene resins used to manufacture PERFORMANCE PIPE polyethylene piping products. It is intended for comparing polyethylene piping resins. It is not a product specification, and it does not establish minimum or maximum values or manufacturing tolerances for resins or for piping products. Some of these typical physical property values were determined using compression molded plaques. Values obtained from tests of specimens taken from piping products can vary from these typical values. This data sheet may be changed from time to time without notice. Contact Performance Pipe to determine if you have the most recent edition.

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DRISCOPIPE® 8100 HDPE Gas Distribution Pipe PE4710-PE100 / (PE3408) Typical Physical Property Pipe Data Sheet			
Property	**Unit**	**Test Procedure**	**Typical Value**
Material Designation	--	**PPI TR-4**	**PE4710** **PE100**
Cell Classification	--	**ASTM D3350**	**445574C** **445576C**
Pipe Properties			
Density	gms / cm^3	ASTM D1505	0.961 (black)
Melt Index (MI) Condition 190/2.16	gms / 10 minutes	ASTM D1238	0.08
Melt Index (HLMI) Condition 190/21.6	gms / 10 minutes	ASTM D1238	7.5
Hydrostatic Design Basis, (73°F)	psi	ASTM D2837	1,600
Hydrostatic Design Basis, (140°F)	psi	ASTM D2837	1,000
Minimum Required Strength	Mpa (psi)	ISO 9080	>10 (>1450)
Rapid Crack Propagation Critical Pressure (Pc), 0°C (32°F)(1)	Bar (psi)	ISO 13477	>30 bar (>435)
Color; UV Stabilizer	---	ASTM D3350	Co-extruded yellow shell UV stabilized for 4 years outdoor storage
Pipe Test Category	---	ASTM D2513	CEE
Material Properties			
Flexural Modulus @2% strain	psi	ASTM D790	>140,000
Elastic Modulus @ Secant 2% strain (2in/min, Type IV bar)	Psi	ASTM D638	>200,000
Tensile Strength at Yield	psi	ASTM D638 (Type IV)	>3,700
Elongation at Break 2 in/min., Type IV bar	%	ASTM D638	>800
Hardness	Shore D	ASTM D2240	65
PENT	hrs	ASTM F1473	>2000
Pipe is manufactured to ASTM D2513. Fittings comply with ASTM D2513 and ASTM D3261.			
Thermal Properties			
Vicat Softening Temperature	°F	ASTM D1525	255
Brittleness Temperature	°F	ASTM D746	-180
Thermal Expansion	in / in / °F	ASTM D696	1.0×10^{-4}

(1) Determination made using Small-Scale Steady state. Pc calculated in accordance with ISO 13477
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Driscoplex® 6500 MDPE Gas Distribution Pipe
PE2708/2406
Typical Physical Property Pipe Data Sheet

Property	Unit	Test Procedure	Typical Value
Material Designation	--	**PPI TR-4**	**PE2708/2406**
Cell Classification	--	**ASTM D3350**	**234373E**
Pipe Properties			
Density	gms / cm^3	ASTM D1505	0.939
Melt Index (MI) Condition 190/2.16	gms / 10 minutes	ASTM D1238	0.18
Melt Index (HLMI) Condition 190/21.6	gms / 10 minutes	ASTM D1238	---
Hydrostatic Design Basis, (73°F)	psi	ASTM D2837	1,250
Hydrostatic Design Basis, (140°F)	**psi**	**ASTM D2837**	**1,000**
Minimum Required Strength	Mpa (psi)	ISO 9080	>8.0 (>1160)
Rapid Crack Propagation Critical Pressure (Pc), 0°C (32°F)(1)	Bar (psi)	ISO 13477	>8.5 bar (>123)
Color; UV Stabilizer	---	ASTM D3350	Yellow UV stabilized for 4 years outdoor storage
Pipe Test Category	---	ASTM D2513	CEE
Material Properties			
Flexural Modulus @2% strain	psi	ASTM D790	>100,000
Elastic Modulus @ Secant 2% strain (2in/min, Type IV bar)	Psi	ASTM D638	>86,000
Tensile Strength at Yield	psi	ASTM D638 (Type IV)	>2,800
Elongation at Break 2 in/min., Type IV bar	%	ASTM D638	>800
Hardness	Shore D	ASTM D2240	63
PENT	hrs	ASTM F1473	>2000
Thermal Properties			
Vicat Softening Temperature	°F	ASTM D1525	227
Brittleness Temperature	°F	ASTM D746	-180
Thermal Expansion	in / in / °F	ASTM D696	1.0×10^{-4}
Manufactured to ASTM D2513 for pipe. Fittings comply with ASTM D2513 and ASTM D3261.			

(1) Determination made using Small-Scale Steady state. Pc calculated in accordance with ISO 13477
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Permeability and Permeation

Plastics are permeable to gases to varying degrees. Although the constituents of natural gas can permeate through polyethylene, the volume of gas lost through permeation is generally so low as to have an insignificant effect on the handling of natural gas in a piping system. The American Gas Association (AGA) *Plastic Pipe Manual for Gas Service* lists the permeability of PE 2406 polyethylene pipe to methane, the primary constituent of natural gas, as 4.2×10^{-3}. Using the AGA factor, one mile of 2" SDR 11 PE2708/2406 pipe carrying 100% methane at 60 psi would lose less than 0.27 ft^3 per day.

Other constituents of natural gas are typically heavier than methane, thus less permeable through polyethylene. Hydrogen is the exception; however, the concentration of hydrogen in most natural gas is so low that the actual amount of hydrogen permeation would be insignificant. At low temperatures and higher pressures, heavier hydrocarbon gases such as propane or butane may condense and liquefy in the pipe. Such condensates are known to permeate polyethylene pipe. All types of hydrocarbons (aromatic, paraffinic, etc.) have a similar effect, and the relative effect on different polyethylene pipe resins is essentially the same. Liquid hydrocarbon permeation will affect joining. ***See Cautions on Liquid Hydrocarbon Permeation, page 5.***

Design Pressure

The following formula is used to compute the design pressures for polyethylene piping systems for natural gas service at operating temperatures up to but not over 140°F (60°C). For operating temperatures below 73°F (23°C), use 73°F (23°C) Design Pressures.

$$P = \frac{2S}{(SDR - 1)} \times f$$

Where:

P = Design Pressure in pounds per square inch gauge (psig);

S = Long Term Hydrostatic Strength (Hydrostatic Design Basis) psi, at pipeline operating temperature; See Table 5.

f = Design factor (specified in CFR 192.121); See Table 6.

SDR= Standard Dimension Ratio

$$SDR = \frac{\textit{Pipe Nominal Outside Diameter}}{\textit{Pipe Minimum Wall Thickness}}$$

Table 5: Hydrostatic Design Basis

Hydrostatic Design Basis or Long Term Hydrostatic Strength, S				
Performance Pipe Product Series	73.4F Data	100F Interpolated	120F Interpolated	140F Data
Driscoplex® 6500 Pipe (MDPE)	1250	1250	1000	1000
Driscopipe® 8100 Pipe (HDPE)	1600	1250	1000	1000
Yellowstripe® 8300 Pipe (HDPE)	1600	1250	1000	1000

Table 6: Design Service Factor

Application	Design (service) Factor, f
Gas distribution and transmission per CFR 49 Part 192, §192.121	0.32
Gas distribution and transmission in Canada per CSA Z662-96	0.40
Gas distribution or transmission piping that is permeated by solvating chemicals such as liquid hydrocarbons or liquefied gas condensate	0.25

Operating Pressures (psig)

The following tables provide ***maximum allowable operating pressures (MAOP)*** and recommended maximum design pressure rating (PR) for PE2708 (PE2406) pipes and PE4710/PE100 (PE3408) pipes for gas distribution service at the indicated operating temperatures. PE pipes of the same DR and Material Designation Code but different outside diameters have the same Design (Working) Pressure Ratings. Pipe minimum wall thickness is determined by dividing the pipe average outside diameter (O.D.) by the DR number.

Pressure ratings are calculated in accordance with applicable federal codes. A check should be made to determine if these pressures apply under the state and/or local codes governing the specific application. Use 73°F (23°C) pressure ratings for operating temperatures below 73°F (23°C).

Table 7: MAOP Driscoplex® 6500 MDPE Gas Distribution Pipe (PE2708)

MAOP & Maximum Design Pressure Rating (PR) for Dry Natural Gas Service --				
PE2708 (PE2406)	Drisciplex® 6500 Pipe PE2708 (PE2406) (Class 1, 2, 3, and 4 location per U.S. federal regulations CFR 192.121 – Design (Service) Factor 0.32‡)			
SDR	73ºF (23ºC) *(PSIG)*	100ºF (38ºC) *(PSIG)*	120ºF (48ºC) *(PSIG)*	140ºF (60ºC) *(PSIG)*
7.0	125†	125†	107	107
7.3	125†	125†	102	102
9.0	100	100	80	80
9.3	96	96	77	77
10.0	89	89	71	71
11.0	80	80	64	64
11.5	76	76	61	61
12.5	70	70	56	56
13.5	64	64	51	51

‡ Class 1, 2, 3, & 4 locations per U.S. federal regulations.
† 49 CFR Part 192.123(e) allows and limits design pressure to 125psig, provided the pressure is calculated in accordance with 49CFR 192.121.

Table 8: MAOP Driscopipe® 8100 Pipe & Yellowstripe® 8300 Pipe (PE4710)

MAOP & Maximum Design Pressure Rating (PR) for Dry Natural Gas Service --				
PE4710/PE100 (PE3408)	Driscopipe® 8100 pipe and Yellowstripe® Pipe PE4710-PE100 (Class 1, 2, 3, and 4 location per U.S. federal regulations CFR 192.121 – Design (Service) Factor 0.32‡)			
SDR	73ºF (23ºC) *(PSIG)*	100ºF (38ºC) *(PSIG)*	120ºF (48ºC) *(PSIG)*	140ºF (60ºC) *(PSIG)*
7.0	125†	125†	107	107
7.3	125†	125†	102	100†
9.0	125†	100	80	80
9.3	123†	96	77	77
11.0	102	80	64	64
12.5	89	70	56	56
13.5	82	64	51	51

‡ Class 1, 2, 3, & 4 locations per U.S. federal regulations.
† 49 CFR Part 192.123(e) allows and limits design pressure to 125psig, provided the pressure is calculated in accordance with 49CFR 192.121.

Cold Bending Radius

The allowable cold bending radius for DriscoPlex® 6500 pipe 2406 is dependent upon the pipe OD, DR and the presence of fittings in the bend. See Performance Pipe's Technical Note *PP-819-TN Field Bending of DriscoPlex® PE Piping.*

Table 9: Allowable Cold Bending Radius

Pipe Dimension Ratio	Allowable Cold Bending Radius
9 or less	20 times the pipe OD
>9 to 13.5	25 times the pipe OD
13.5 or greater	27 times the pipe OD
Fitting or flange present in the bend	100 times the pipe OD

Special Considerations for Plowing and Planting

Plowing and planting involve cutting a narrow trench and feeding the pipe into the trench through a shoe or chute fitted just behind the trench cutting equipment. The shoe or chute feeds the pipe into the bottom of the cut. The minimum bend radius of the pipe through the shoe may be tighter than the minimum bend radius of the pipe used for a permanent long-term installation, but it must not be so tight that the pipe kinks. Table 10 presents the minimum short-term bend ratio for applications such as plowing and planting. The pipe's path through the shoe or chute should be as friction free as practicable to reduce additional outerfiber tensile stresses. Generally plowing and planting is limited to 12" and smaller pipes.

Table 10: Minimum Short-term Cold Bending Radius

Pipe Dimension Ratio	Minimum Short-Term bending Radius
9	10
>9 to 13.5	13
>13.5 to 17	17

Propane (LPG) Gas Service

The Office of Pipeline Safety Advisory Bulletin No. 73-4, dated April 1973, states, "It is the operator's responsibility to assure the integrity of the plastic pipe selected for use in the piping system, and this should be based on a favorable recommendation from the manufacturer. Therefore, the Federal minimum safety standards do permit the use of plastic in a properly engineered underground system of LPG distribution conforming to the limitations of these regulations." DriscoPlex® 6500 pipe (PE2708), Driscopipe® 8100 pipe (PE4710) and Yellowstripe® 8300 pipe (PE4710) series products meet the requirements of ANSI/NFPA 58 *Standard for the Storage and Handling of Liquefied Petroleum Gases.*

The Plastics Pipe Institute has made the following "Use Recommendation" for polyethylene piping systems for commercial propane systems:

PPI Use Recommendation (Technical Report TR-22)

The information collected indicates that polyethylene plastic piping is satisfactory for transporting LPG and its major component, propane gas. This information also indicates that pressure design parameters based on propane gas should be adequate and reasonable. However, until more information is available, these use recommendations cover only commercial propane vapor in detail.

1. The polyethylene plastic pipe, tubing and fittings should be only those specific types designated as PE 2708 or PE 4710 and meeting the appropriate requirements of ASTM D 2513.
2. A Hydrostatic Design Basis of 1000 psi should be used in the design of polyethylene pipe systems for propane gas distribution at pipe temperatures of 73°F or lower. The long-term hydro static strength measurements should be made in accordance with ASTM D 2837.
3. Polyethylene should be used only in underground propane gas distribution systems designed to operate at internal pressures and temperatures such that condensation will not occur.

It is also recommended that operating pressures be limited to 30 psig or less.

In cases where condensation does occur in a propane system or propane enriched system and the presence of condensation is of relatively short duration, there is no indication of loss of physical integrity or observable change in polyethylene pipe. Under actual operating conditions, in a properly designed system, the pressures and temperatures are such that revaporization of any propane condensates will usually occur. Experience with propane liquids in polyethylene shows that there is no cumulative effect of intermittent, short duration exposure of propane condensate in polyethylene. For additional information, see PPI Technical Report TR-22. Exposure to liquefied propane condensates for extended periods may affect joining.

Mercaptans

Mercaptans are a group of organic compounds containing a Sulfur-Hydrogen bond that have a distinct odor in small concentrations. Natural gas is an odorless hydrocarbon. Natural gas carriers and distributors add mercaptans to natural gas to warn of leaks and to alert the presence of natural gas atmospheres. New plastic pipes have the tendency to absorb mercaptans, causing the odor to fade or become faint. The effect is not long term and after a period of time the distinctive odor of mercaptan is readily detected when released.

Mercaptan enriched natural gas has the possibility of inducing a phenomenon known as "odor fatigue." The condition can cause nasal passages to become saturated with the smell of gas over time, making it difficult to continue to detect the mercaptan odor.

When Performance Matters Rely on
Performance Pipe

CONTACT INFORMATION:

Performance Pipe
A Division of Chevron Phillips Chemical Company LP
5085 W. Park Blvd, Suite 500
Plano, TX 75093
Phone: 800-527-0662 Fax: 972-599-7329

Visit Performance Pipe on the web for the latest literature updates.
www.performancepipe.com

POLYBALL®
NATURAL GAS VALVES

Polyethylene Valves for Natural Gas.

KEROTEST®
SINCE 1909

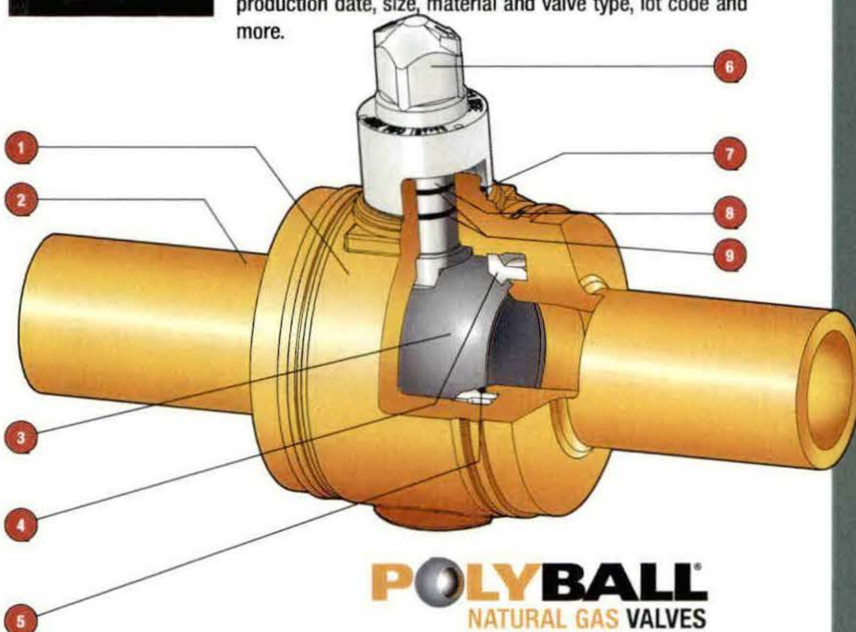
Providing valves and equipment to the world's energy markets for over 100 years.

Polyethylene Valves Made in the U.S.A.

The POLYBALL valve is manufactured at our Mansura, Louisiana, facility, which is ISO 9001:2002 certified as a Quality Management System. Custom, dedicated tooling and equipment have been developed for every valve size to achieve and maintain quality levels during production and minimize variation in all processes.

At assembly, each valve is assigned a unique serial number that provides complete traceability for critical components. The serial number allows complete traceability from the customer's installation back to the raw material.

All POLYBALL valves now feature the new industry-standard tracking and traceability code per ASTM F2897 that allows instant access to individual valve specifications. With decoding software, simply scan the bar code to see the production date, size, material and valve type, lot code and more.



POLYBALL
NATURAL GAS VALVES

MATERIALS OF CONSTRUCTION

NO.	COMPONENT	MATERIAL	FEATURES AND BENEFITS
1	Body	POLYETHYLENE	PE 2708, medium density PE 4710, high density
2	Ends	POLYETHYLENE	PE 2708, various SDRs PE 4710, various SDRs
3	Ball	POLYPROPYLENE	High strength, long life and low operating torque
4	Retainer	POLYPROPYLENE	Positive restraint under any condition; retains seat under high differential pressure
5	Ball Seat	BUNA-N	Reliable sealing from -20°F to 140°F
6	Actuator	POLYPROPYLENE	2" operating square, positive position indication, over-torque protection
7	Weather Seal	BUNA-N	Protects from groundwater and dirt
8	Stem	ACETAL *	Excellent durability and strength, blowout proof
9	Stem Seals	BUNA-N	Redundant sealing with dual o-rings

** Stem is stainless steel on 2" RP, 1 1/2" FP, 1 1/4" FP sizes.*

POLYBALL®
NATURAL GAS VALVES

Polyethylene Valves

Made in the U.S.A.

Kerotest Manufacturing Corp. has more than a 100-year commitment to the gas distribution industry. So Polyball will always be American made, supported and distributed, with ample inventory at all times.

Full port and reduced port sizes from 1/2" to 12" IPS.

Metric sizes from 20mm to 315mm.

Made to perform and comply

- 49 CFR Part 192
- ASTM D2513
- ASTM F2897
- ASME B16.40
- CSA standard B137.4 - 02
- CSA International certified (Canadian Standard Association)

Available with High Head Extensions in varying heights to meet specific installation requirements. These valves meet the same strict standards of all Polyball valves.

Made to meet your needs in these applications:

- Natural Gas Distribution
- Natural Gas Gathering
- Landfill Gas (Methane)
- Air
- Inert Gases (Argon, Helium, Neon)

GENERAL INFORMATION

ITEM	OPERATING FEATURES
OPERATING	PE 2708 : 80 psig (5.5 bar), SDR 11 PE 4710 : 100 psig (6.9 bar), SDR 11 PE 4710 : 125 psig (8.6 bar), SDR 7.0, 9.0, 9.3
MATERIALS	Medium Density Polyethylene (PE 2708) High Density Polyethylene (PE 4710)
TEMPERATURE	From -20°F to 140°F (-29°C to 60°C)
PIPE CONNECTION VIA	Butt Fusion, Mechanical Fittings, Electrofusion
BORE	Full Port or Reduced Port
STEM TYPE	Standard or High Head Extended Stem, Length as Required
SDR	SDRs available: 7.0, 9.0, 9.3, 11, 11.5, 12.5, 13.5, 15.5, 17, 21

KEROTEST®
SINCE 1909

Providing valves and equipment to the world's energy markets for over 100 years.

Kerotest Manufacturing Corp.
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412-521-7688 • Fax: 412-521-5990
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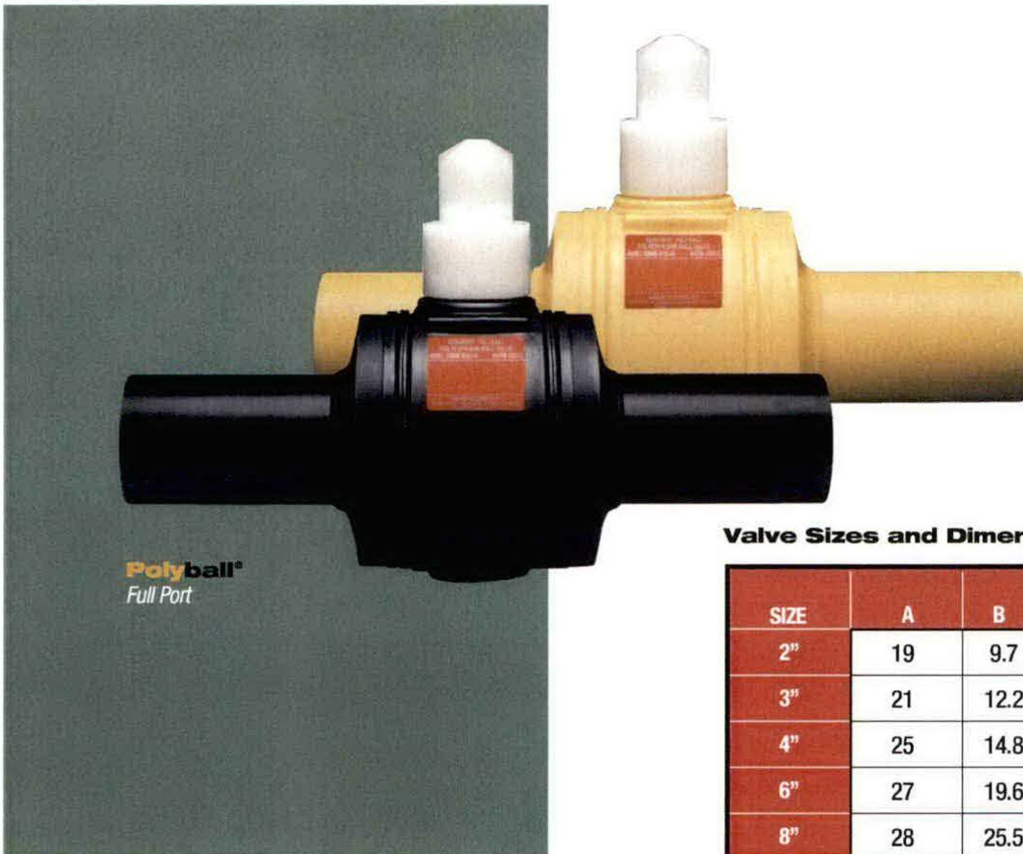
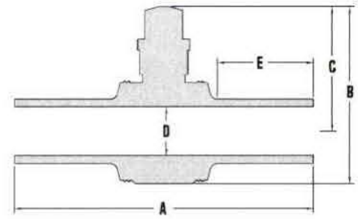




Valve Sizes and Dimensions (Approx. inches) Full Port

SIZE	A	B	C	D	E	Cv	WEIGHT (lbs)
2"	19	9.7	7.0	1.90	6.4	180	5
3"	21	12.2	8.7	2.70	6.4	400	10
4"	25	14.8	10.2	3.63	7.5	710	20
6"	27	19.6	13.2	5.25	7.0	1290	42
8"	28	25.5	17.2	6.70	5.3	2119	96
12"	82	31.3	19.4	10.10	28	5400	396

12" POLYBALL Full Port features a 10.1" port opening.

Body is high-density PE 4710 polyethylene.

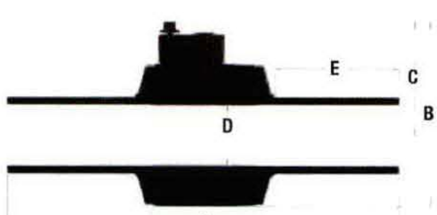
Nipple extensions available in PE 4710 or PE 2708.

Available SDRs: 9, 11, 13.5, 17

The gearbox features a 6:1 ratio and is also sealed against outside contaminants, making it virtually waterproof.

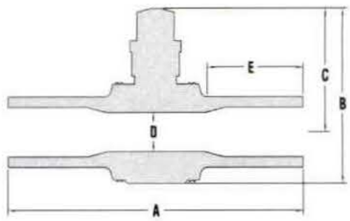
12" Full Port is also available with bypass option.

All POLYBALL valves now feature the new industry standard tracking and traceability code per ASTM F2897 that allows instant access to individual valve specifications. With decoding software, simply scan the bar code to see the production date, size, material and valve type, lot code and more.



12" FULL PORT DIMENSIONS (Approx. Inches)

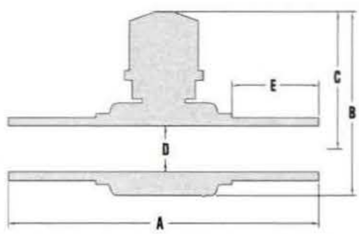
A	B	C	D	E	Weight (lbs)	SDR
82	31.3	19.4	10.10	28	396	9 to 21



Polyball®
Reduced Port

Valve Sizes and Dimensions (Approx. inches) **Reduced Port**

SIZE	A	B	C	D	E	Cv	WEIGHT (lbs)
3"	19	9.6	6.9	1.90	6.8	180	5.3
4"	21	12.2	8.7	2.70	6.5	450	11
6"	25	14.8	10.2	3.63	7.3	910	26
8"	27	19.6	13.2	5.25	7.2	1290	47
10"	28	25.5	17.2	6.70	5.5	2119	102
12"	28	25.5	17.2	6.70	5.7	2119	110

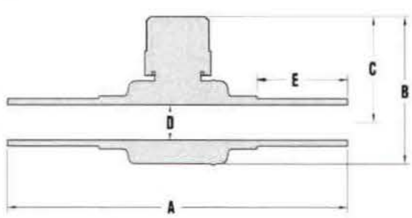


Polyball®

Valve Sizes and Dimensions (Approx. inches)

SIZE	A	B	C	D	E	Cv	WEIGHT (lbs)
F 1.25"	11.8	6.9	5.2	1.38	3.2	100	2
F 1.5"	11.8	6.9	5.2	1.38	3.2	150	2
R 2"	11.8	6.9	5.2	1.38	3.2	150	2

(F) Full Port (R) Reduced Port



Polyball®
Service Valve

Valve Sizes and Dimensions (Approx. inches) **Service Port**

SIZE	A	B	C	D	E	Cv	WEIGHT (lbs)
1/2" CTS	12	5.2	3.7	1.01	3.0	7	1
1/2" IPS	12	5.2	3.7	1.01	3.0	21	1
3/4" CTS	12	5.2	3.7	1.01	3.0	22	1
3/4" IPS	12	5.2	3.7	1.01	3.0	30	1
1" CTS	12	5.2	3.7	1.01	3.0	33	1
1" IPS	12	5.2	3.7	1.01	3.2	42	2
1.25" CTS	12	5.2	3.7	1.01	3.2	45	2
1.25" IPS	12	5.2	3.7	1.01	3.2	49	2

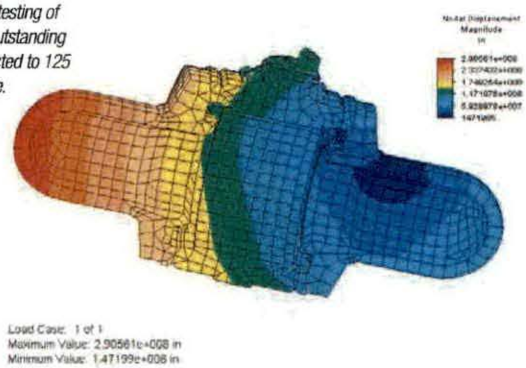
All dimensions are approximate and subject to change. Consult factory for certified dimensions.

Pass with Flying Colors

Kerotest Polyball Polyethylene Ball Valves meet the requirements of ASME B16.40: Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems.

Independent third-party evaluation. A complete report, demonstrating compliance with ASME B16.40 is available upon request. All qualification and production tests were successfully completed. Additional tests performed by Kerotest beyond the B16.40 requirements include Burst Test, Cycle Test, Impact Test, Bend Test and Tensile Test.

Linear static stress testing of Polyball delivered outstanding results when subjected to 125 psi internal pressure.



All valves are in full compliance with ASME B16.40.

TEST ITEM	TEST METHOD	SDR 11 MEDIUM DENSITY PE 2708 HIGH DENSITY PE 4710	SDR 9.0 HIGH DENSITY PE 4710
SEAT TEST	Air seat test under water, both directions	4 psi (0.3 bar) 150 psi (10.4 bar)	4 psi (0.3 bar) 190 psi (13 bar)
SHELL TEST	Air test under water	4 psi (0.3 bar) 150 psi (10.4 bar)	4 psi (0.3 bar) 190 psi (13 bar)
OPERATIONAL TESTING	Valve operated 10 times at full differential pressure at -20°F and 140°F (-29°C to 60°C)	100 psi (6.9 bar)	125 psi (8.6 bar)
BEND TEST	20 pipe diameters bend radius at differential pressure operation, seat leakage checked	10 psi (0.7 bar) 100 psi (6.9 bar)	10 psi (0.7 bar) 125 psi (8.6 bar)
TORQUE TEST	Operating torque at -20°F and 100°F (-29°C to 38°C)	100 psi (6.9 bar)	125 psi (8.6 bar)
SUSTAINED PRESSURE TEST	Tested at 176°F (80°C)	134 psi (9.2 bar) DR 11	148 psi (10.2 bar) DR 9.0
HIGH PRESSURE TEST	High pressure Shell Test	> 600 psi (41 bar)	> 700 psi (48 bar)

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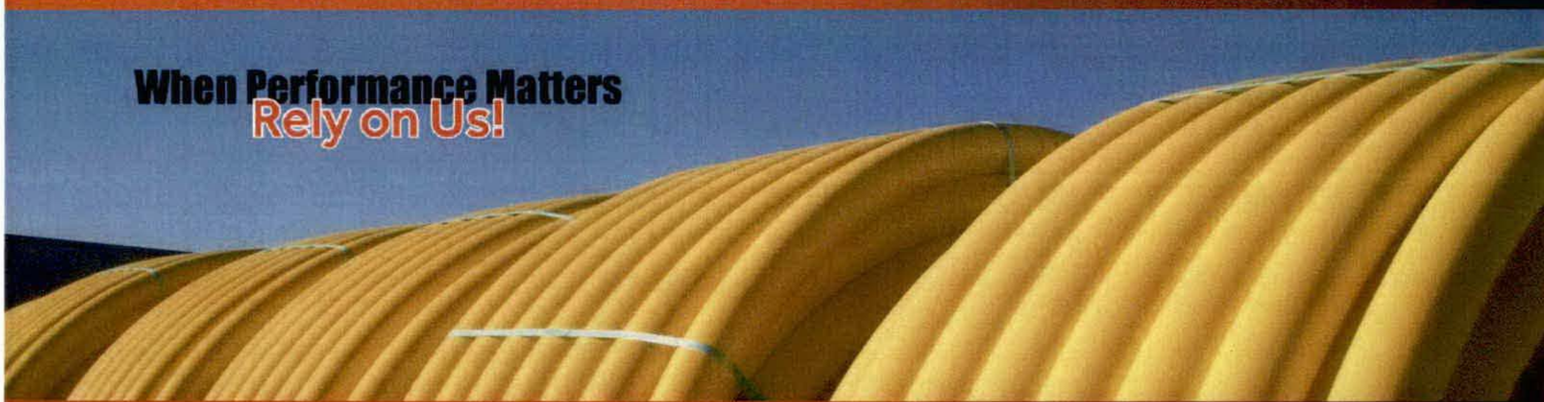
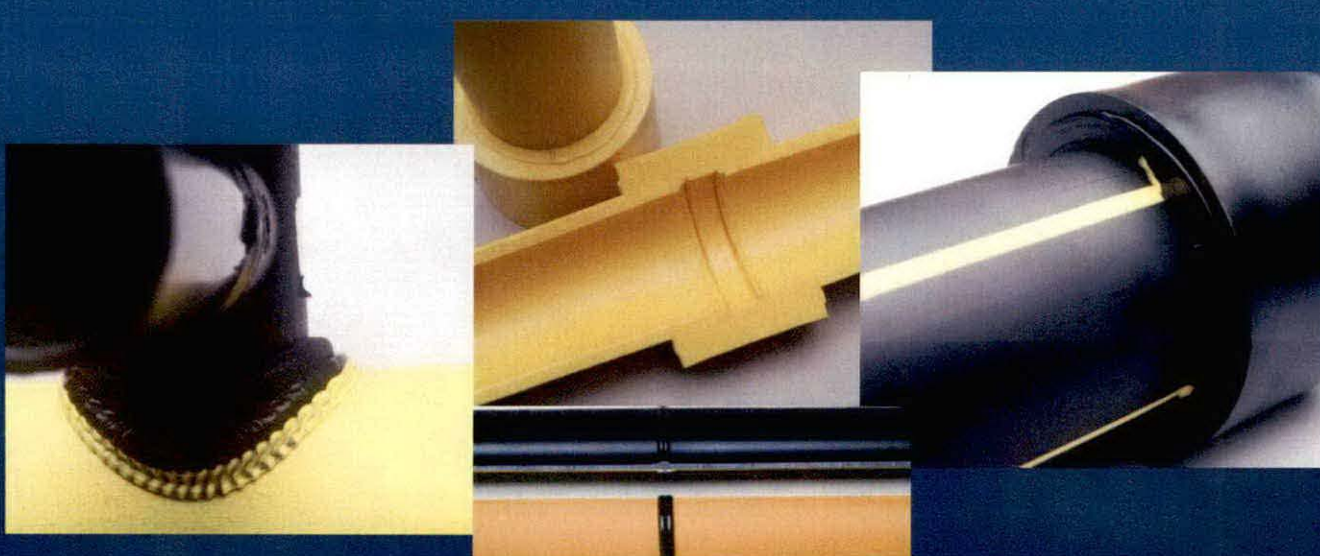
PERFORMANCE PIPE

A DIVISION OF CHEVRON PHILLIPS CHEMICAL COMPANY LP



Heat Fusion Joining Procedures and Qualification Guide

Gas Distribution, Water, Industrial, Specialty and Energy Products



DriscoPlex
Polyethylene Pipe & Fittings

Performance Pipe

Heat Fusion Joining Procedures

Introduction

Performance Pipe, a Division of Chevron Phillips Chemical Company LP, is the functional successor to the operations of Plexco® and Driscopipe® PE piping. As a result, some Performance Pipe products may have the markings of the Plexco®, Driscopipe® or DriscoPlex® PE piping brands.

This Manual describes procedures and guidelines for joining Performance Pipe products using butt fusion, saddle fusion and socket fusion joining techniques. All procedures and guidelines in this document are in alignment with ASTM F2620 Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings

Qualification of Procedure

When used to join Performance Pipe polyethylene gas distribution pipe and fittings, Performance Pipe fusion joining procedures are qualified in accordance with U.S. Department of Transportation Regulation 49 CFR, Part 192, §192.273(b).

Gas Distribution Products

DriscoPlex® 6500 PE Piping	Driscopipe® 6800 Piping	Plexco Plexstripe II PE 3408 Mining Pipe
Driscopipe® 6500 PE Piping†	Driscopipe® 8100 PE Piping	Plexco® Yellowstripe™ PE 3408 Piping
DriscoPlex® 6800 Piping	Plexco® Yellow Pipe PE 2406 Piping	YELLOWSTRIPE® 8300 PE Piping

All Gas Distribution products listed above are compatible with these procedures. **Do not join Driscopipe® 7000 or 8000 PE Piping using these procedures.**

Water, Specialty, Municipal and Industrial Products

DriscoPlex® 4100 PE Piping	DriscoPlex® 4100 PE Piping	DriscoPlex® 4700 PE Piping	Plexco® Plexvue
Driscopipe® 4100 PE Piping	Driscopipe® 4100 PE Piping	DriscoPlex® 4800 PE Piping	Plexco® Purplestripe™ PE 3408
DriscoPlex® 4200 PE Piping	DriscoPlex® 4200 PE Piping	DriscoPlex® 5100 PE Piping	Plexco® Redstripe™ FM PE 3408
Driscopipe® 4200 PE Piping	Driscopipe® 4200 PE Piping	DriscoPlex® 5300 PE Piping	Plexco® Bluestripe™ FM PE 3408
DriscoPlex® 4300 PE Piping	DriscoPlex® 4300 PE Piping	Driscopipe® 5300 PE Piping	Plexco® PE 3408 Oil & Gas Gathering Pipe
Driscopipe® 4300 PE Piping	Driscopipe® 4300 PE Piping	DriscoPlex® 6400 PE Piping	
DriscoPlex® 4400 PE Piping	DriscoPlex® 4400 PE Piping	Driscopipe® 6400 PE Piping	
Driscopipe® 4400 PE Piping	Driscopipe® 4400 PE Piping	DriscoPlex® 8700 PE Piping	
DriscoPlex® 1700 PE Piping	DriscoPlex® 4500 PE Piping	Driscopipe® 8700 PE Piping	
DriscoPlex® 4000 PE Piping	Driscopipe® 4500 PE Piping	DriscoPlex® 9200 PE Piping	
Driscopipe® 4000 PE Piping	DriscoPlex® 4600 PE Piping		

All Water, Specialty, Municipal and Industrial products listed above are compatible with these procedures. Do not join Driscopipe® 7600 or 8600 PE Piping using these procedures.

Performance Pipe, a Division of Chevron Phillips Chemical Company LP | 5085 W. Park Blvd | Suite 500 | Plano, TX 75093 | Phone: 800-527-0662 | Fax: 972-599-7329

OVERVIEW

In heat fusion joining, mating surfaces are prepared and simultaneously melted with a hot-plate heater. The heater is then removed and the melted surfaces are pressed together and held under pressure. As the molten materials cool, they mix and fuse into a permanent, monolithic joint. Heat fusion procedures require specific tools and equipment based on the fusion type and the sizes of pipe and fittings being joined.

- Butt fusion is used to make end-to-end joints between "butt" or plain-end pipes and fittings that have the same outside diameter and "like wall thickness".
  - ✓ *"Like wall thickness"* means that the pipe or fitting ends being butt fused do not exceed one SDR difference (e.g. SDR 9.0 to SDR 11.0). Per ASTM, standard dimension ratio (SDR) is when the outside diameter divided by the minimum wall thickness equals one of the following values: 6.0, 7.3, 9.0, 11.0, 13.5, 17.0, 21.0, 26.0, 32.5 or 41.0.
- Saddle (sidewall) fusion is used to install a branch outlet fitting to the top or side of a pipe main. Tapping tee fittings are usually installed on top of the pipe main, while branch or service saddle fittings are installed on the side of the main. After the joint has cooled, the main pipe wall is pierced (tapped) to enable flow through the branch. "Hot tapping" is saddle fusion to a "live" or pressurized main.
- Socket fusion is used to join 4" IPS and smaller tubing and pipe to socket fittings. Socket fittings are available for certain Performance Pipe PE materials.

❖ ***CAUTION — Performance Pipe polyethylene piping products cannot be joined with adhesives or solvent cement. Joining by hot air (hot gas) welding or extrusion welding techniques and joining by pipe threading are not recommended for pressure service.***

PRECAUTIONS

STATIC ELECTRICITY

Polyethylene plastic pipe does not readily conduct electricity. A static electricity charge can build up on inside and outside surfaces and stay on the pipe surface until some grounding device such as a tool or a person comes close enough for the static electricity to discharge to the grounding device.

- Discharging one part of the pipe surface will not affect other charged areas because static electricity does not flow readily from one area to another. Polyethylene pipe cannot be discharged by attaching grounding wires to the pipe.

◆ ***WARNING – Fire or Explosion – Static electricity discharge can ignite a flammable gas or combustible dust atmosphere.***

A static electricity discharge to a person, a tool or a grounded object close to the pipe surface can cause an electric shock or a spark. That can then ignite a flammable gas or combustible dust atmosphere causing fire or explosion.

- In gas utility applications, static electricity can be a potential safety hazard. **Where a flammable gas-air mixture may be encountered and static charges may be present, such as when repairing a leak, squeezing-off an open pipe, purging, making a connection, etc., arc preventing safety precautions are necessary.[1] Observe all Company (pipeline operator, utility, contractor, etc.) procedures for static electricity safety and control, including procedures for discharging static electricity and requirements for personal protection.**
- Take steps to discharge static electricity from the surface of a polyethylene gas pipe. Such steps include wetting the entire exposed pipe surface with a conductive anti-static liquid or a dilute soap and water solution, then covering or wrapping the entire wetted, exposed pipe surface with grounded wet burlap, conductive poly film or wet tape conductor. The external covering should be kept wet by occasional re-wetting with anti-static solution. The covering or tape should be suitably grounded such as to a metal pin driven into the ground.
- Steps that discharge the outer surface do not discharge the inner surface of the pipe. Squeeze-off, purging, venting, cutting, etc., can still result in a static electricity discharge. When appropriate, ground tools and remove all potential sources of ignition.
- Appropriate safety equipment should be used.
- **Do not use polyethylene pipe for handling dry grain or coal where a static electricity discharge may ignite a combustible dust atmosphere and cause an explosion or fire.**
- Polyethylene pipe is not recommended for pneumatic slurry applications.

ELECTRIC TOOLS

◆ ***WARNING – Fire or Explosion – Electric tools or fusion equipment may not be explosion-proof and may ignite a flammable gas or flammable dust atmosphere.***

***DO NOT* operate electrical devices that are not explosion proof in a flammable gas or flammable dust atmosphere. When a flammable gas-air mixture may be present, observe all gas system operator (pipeline or utility company and contractor) safety procedures for the use of electric tools and equipment.**

LIQUID HYDROCARBON PERMEATION

When present, liquid hydrocarbons may permeate (solvate) polyethylene pipe. Liquid hydrocarbon permeation may occur when: 1) liquid hydrocarbons are present in the pipe; 2) where soil surrounding the pipe is contaminated with liquid hydrocarbons; or 3) where liquid hydrocarbon condensates can form in gas pipelines. Heat fusion joining to liquid hydrocarbon permeated pipes may result in a low strength joint.

[1] See the *AGA Plastic Pipe Manual For Gas Service 2000*, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209.

❖ ***CAUTION — Once polyethylene pipe has been permeated with liquid hydrocarbons, heat fusion or electrofusion joining is not recommended because liquid hydrocarbons will leach out during heating and contaminate the joint. Liquid hydrocarbon permeated polyethylene pipe should be joined using suitable mechanical connection methods. Contact the mechanical joining product manufacturer for connection and installation procedures.***

Liquid hydrocarbon contamination is indicated by a rough, sandpaper-like, bubbly or pockmarked surface when a fusion heating iron is removed from the pipe surface, and may be indicated by discoloration or by a hydrocarbon fuel odor. See the *PPI Handbook of Polyethylene Pipe* for additional information on permeation and chemical resistance.

LEAKAGE AT FUSION JOINTS

◆ ***WARNING – Correctly made fusion joints do not leak. When pressurized, leakage at a faulty fusion joint may immediately precede catastrophic separation and result in violent and dangerous movement of piping or parts and the release of pipeline contents under pressure. Never approach or attempt to repair or stop leaks while the pipeline is pressurized. Always depressurize the pipeline before making corrections. Faulty fusion joints must be cut out and redone.***

HANDLING

Polyethylene piping is a tough, robust material, but it is not immune to damage. **Improper handling or abuse can damage piping, compromise system performance and result in injury or property damage.** Polyethylene piping should be unloaded and moved with proper handling and lifting equipment. Use fabric slings. Do not use chains or wire ropes. Do not roll or drop pipe off the truck or drag piping over sharp rocks or other abrasive objects. Store piping so that the possibility of mechanical damage is minimized. Visit www.performancepipe.com for additional information on handling and storage.

FUSION IN COLD WEATHER

In cold weather, polyethylene becomes more sensitive to impact and is less flexible. Use additional care in handling. When temperatures are cold, avoid sharp impact such as dropping the pipe from moderate heights. Cold pipes will be harder to bend or uncoil.

Butt, Saddle, or Socket Fusion is generally not recommended below -4°F (-20°C) without special provisions such as a portable shelter or trailer or other suitable protective measures with auxiliary heating. In inclement weather and especially in windy conditions, the fusion operation should be shielded to avoid precipitation or blowing snow and excessive heat loss from wind chill. Remove all frost, ice or snow from the OD and ID surfaces of areas to be fused. Surfaces must be clean and dry before fusing.

- Maintain the specified heating tool surface temperature. **Do not increase heating tool surface temperature.**
- Do not apply pressure during zero pressure butt or saddle fusion heating steps.

- Do not increase butt or saddle fusion joining pressure.
- When making a butt fusion joint with the ambient temperature below 3°F(-16°C), pre-heat the pipe ends using a heating blanket or warm air device to elevate the pipe temperature to improve the heating starting condition.
    - With pipe mounted in the fusion machine, an alternate method of pre-heating is to stop the pipe ends within .25-.50 inches (6.4-12.7mm) of the heater plate face to allow the pipe ends to warm for 30 seconds to 2 minutes, depending on the pipe size and wall thickness.

❖ ***CAUTION - The use of direct application open flame devices, such as torches, for heating polyethylene pipe is prohibited due to the lack of adequate heating control and possibility of damage to the pipe ends.***

- When fusing coiled pipe when the ambient temperature is below 32°F (0°C), it may be required to remove an end section of pipe from the coil and butt fuse on a straight section of pipe to enable correct pipe alignment. Completed joints shall be allowed to cool to ambient temperature before any stress is applied.

When fusing in cold weather, the time required to obtain the proper melt may increase.

- In butt fusion, melt bead size determines heating time. As a result, the procedure automatically compensates when cold pipe requires longer time to form the proper melt bead size.
- For saddle fusion, establish the necessary cold weather heating time by making trial melt patterns in the field on **non-pressurized**, excess pipe that is at field temperature. Use the standard heating time, plus additional heating time in 3-second increments during bead-up, until the proper melt pattern is established on the pipe. A clean wood board or heat shield ("flyswatter") should be used between the saddle fitting and the heater to avoid heating the fitting when making trial melt patterns.
- In socket fusion, it will be more difficult to fit a cold socket fitting into the heating tool socket face because polyethylene pipe and fittings will contract slightly in the cold. One way to compensate is to warm the socket fitting in the cab of the service truck before use. For the pipe, establish the necessary heating time by making trial patterns on excess pipe that is at field temperature. Use the recommended heating time, plus additional heating time in 3-second increments, until the proper melt pattern is established.

Additional information on fusion in cold weather can be found in Annex 1 of ASTM F2620 *Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings.*

KEY FACTORS FOR QUALITY FUSIONS

Quality fusion requires using all of the required tools and equipment, and following all of the steps in the procedure in the correct sequence. Faulty fusion is caused by improper or defective equipment, omitting steps or doing things out of sequence.

Training and experience provide knowledge and proficiency in what to do, what to expect and recognizing potential problems in advance. Inadequately trained or inexperienced persons can produce poor quality fusions and may expose themselves or others to hazards. Federal safety regulations require that persons making joints in gas systems must be qualified in the pipeline operator's qualified fusion procedures (CFR 49, Part 192).

The key factors below are necessary for quality fusion:

- Fusion tools and equipment must be correct for the job and in proper working order.

  Each fusion procedure requires specific tools and equipment to do the job properly. Incorrect or poorly maintained or damaged fusion tools or equipment or using the wrong tools or equipment can cause a poor fusion and may be hazardous. Use only the correct tools and equipment for the job. Do not use defective or improper tools or equipment. Follow the equipment manufacturer's procedures for equipment maintenance.

- The fusion operator must be proficient in tool and equipment use and operation, and proficient in fusion procedure.

  The operator should be thoroughly familiar with the tools and equipment and their use and operation. Improper use or an incorrect operating sequence can cause a poor fusion and may be hazardous. Know how to use the equipment and observe the manufacturer's instructions.

- Pipe and fitting surfaces must be clean and properly prepared.

  Dirty, contaminated or poorly prepared surfaces that do not mate together properly cannot produce a quality fusion. Clean and prepare the surfaces before joining. If contamination is reintroduced, clean the surfaces again.

- Heating tool surfaces must be clean, undamaged and at the correct surface temperature.

  Heating tool faces have non-stick coatings for quick, complete release from melted polyethylene. Dirty or contaminated heating tool faces can cause poor fusion and damaged coatings may not release properly from the melt. Use only wooden implements and clean, dry non-synthetic (cotton) cloths or paper towels to clean heating tool faces. Never use spray chemicals or metal tools on heating tool faces.

  Heating tool temperatures are specified for each procedure. (Butt fusion and saddle fusion heating tool temperatures are different.) *The specified temperature is the temperature on the surfaces that contact the pipe or fitting being joined, not the heating tool thermometer temperature.* Use a pyrometer or infrared thermometer to check for uniform temperature across both of the component contact surfaces. *(Temperature indication crayons are not preferred. If used, temperature-indicating crayons must never be applied to a surface that contacts a pipe or fitting.)* Uneven temperature may indicate a faulty heater. The heater thermometer measures the internal temperature, which is usually higher than surface temperature; however, heating tool temperature can be verified by checking the thermometer to ensure that the heating tool is maintaining temperature. When checking surface temperature with a pyrometer or infrared thermometer, note the heating tool thermometer reading. Check the heating tool thermometer reading before each fusion to verify that the heating tool is maintaining temperature properly. Incorrect or non-uniform temperature can cause poor fusion; **low heating tool temperature can lead to a blowout during hot tap saddle fusion**.

BEFORE YOU START:

- ✓ Inspect pipe lengths and fittings for unacceptable cuts, gouges, deep scratches or other deleterious defects. Damaged products should not be used.
- ✓ Remove surface damage at pipe ends that could compromise the joining surfaces or interfere with fusion tools or equipment.
- ✓ Be sure all required tools and equipment are on site, in proper working order and fueled up.
- ✓ The pipe and fitting surfaces where tools and equipment are fitted must be clean and dry. Use clean, dry, non-synthetic (cotton) cloths or paper towels to remove dirt, snow, water and other contamination. 90% or greater isopropyl alcohol may be used to clean extremely dirty pipe before facing, **NEVER** after facing.
- ✓ Shield heated fusion equipment and surfaces from inclement weather and winds. A temporary shelter over fusion equipment and the fusion operation may be required.
- ✓ Relieve tension in the line before making connections.
- ✓ When joining coiled pipe, making an s-curve between pipe coils can relieve tension. In some cases, it may be necessary to allow pipe to equalize to the temperature of its surroundings. Allow pulled-in pipes to relax for several hours to recover from tensile stresses.
- ✓ Pipes must be correctly aligned before making connections.

◆ ***WARNING – Impact Hazard – Do not bend pipe into alignment against open butt fusion clamps. The pipe may spring out and cause injury or damage. Pipe must be aligned before placing it into butt fusion equipment.***

BUTT FUSION

SET-UP PARAMETERS

HEATING TOOL SURFACE TEMPERATURE - MINIMUM 400°F – MAXIMUM 450°F (204–232°C)

Heating tool surfaces must be clean and up to temperature before beginning the fusion procedure. All points on both heating tool surfaces where the heating tool surfaces will contact the pipe or fitting ends must be within the prescribed minimum and maximum temperatures.

GAUGE PRESSURE

Gauge pressure is the pressure required for fusion. For hydraulic machines, the gauge pressure is a function of interfacial pressure, fusion surface area, machine's carriage cylinder size and drag pressure. When calculated, gauge pressure is what the operator will input into the fusion machine. The total effective piston area can be obtained from the machine manufacturer. The drag pressure is the pressure that is required to overcome movement in the carriage. ***Interfacial pressure and gauge pressure are not the same.*** Manually operated machines do not require a calculation for gauge pressure. Below is

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the equation used to calculate for Gauge Pressure in psi. **A slide rule or a gauge pressure calculator obtained from the machine's manufacturer can be a substitute for this calculation.**

$$P_G = \frac{\left[OD^2 \times \pi \times \left(\frac{1}{DR} - \frac{1}{DR^2}\right)\right] \times IFP}{TEPA} + P_D$$

P_G = Gauge Pressure, psi
OD = Outside Diameter, in.
DR = Dimension Ratio
IFP = Interfacial Pressure,
60 – 90 psi (4.14 – 6.21 bar)
P_D = Drag Pressure, psi
TEPA = Total Effective Piston Area, in^2

PROCEDURE

1. ***Secure.*** Clean the inside and outside of the component (pipe or fitting) ends by wiping with a clean, dry, lint-free cloth or paper towel. Remove all foreign matter. Align the components with the machine, place them in the clamps and then close the clamps. ***Do not force pipes into alignment against open fusion machine clamps***. (When working with coiled pipe, if possible "S" the pipes on each side of the machine to compensate for coil curvature and make it easier to join.) Component ends should protrude past the clamps enough so that facing will be complete. Bring the ends together and check high-low alignment. Adjust alignment as necessary by tightening the high side down.
2. ***Face.*** Place the facing tool between the component ends and face them to establish smooth, clean, parallel mating surfaces. Complete facing produces continuous circumferential shavings from both ends. Face until there is a minimal distance between the fixed and moveable clamps. Some machines have facing stops. If stops are present, face down to the stops. Remove the facing tool and clear all shavings and pipe chips from the component ends. ***Do not touch the component ends with your hands after facing***.
3. ***Align.*** Bring the component ends together, check alignment and check for slippage against fusion pressure. Look for complete contact all around both ends with no detectable gaps and outside diameters in high-low alignment. If necessary, adjust the high side by tightening the high side clamp. Do not loosen the low side clamp because components may slip during fusion. Re-face if high-low alignment is adjusted.
4. ***Melt.*** Verify that the heating tool is maintaining the correct temperature. Place the heating tool between the component ends and move the ends against the heating tool. The initial contact should be under moderate pressure to ensure full contact then reduce to contact pressure only.

   On larger sizes (14" and larger), hold fusion pressure until an indication of melt is observed around the pipe ends before reducing pressure.

   Hold the ends against the heating tool **without force**. Beads of melted polyethylene will form against the heating tool at the component ends. Use **Table 1** to approximate the melt bead size from the pipe OD. When the proper melt bead size is formed, quickly separate the ends and remove the heating tool. This process should be completed within the recommended time in **Table 2**.

Table 1: Approximate Melt Bead Size

Pipe OD, in. (mm)	***Approximate Melt Bead Size, in. (mm)***
< 2.37 (60)	1/32 (1)
≥ 2.37 (60) ≤ 3.5 (89)	1/16 (1.5)
> 3.5 (89) ≤ 8.62 (219)	3/16 (5)
> 8.62 (219) to ≤ 12.75 (324)	1/4 (6)
> 12.75 (324) to ≤ 24 (610)	3/8 (10)
> 24 (610) to ≤ 36 (900)	7/16 (11)
> 36 (900) to ≤ 65 (1625)	9/16 (14)

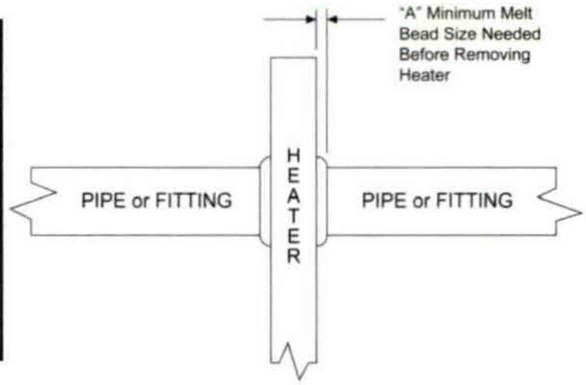


Table 2: Maximum Heater Plate Removal Times

Field Applications Pipe Wall Thickness, in. (mm)	***Common Gas Pipe OD Sizes***	***Maximum Heater Plate Removal Time (Seconds)***
0.20 to 0.36 (5 to 9)	2" DR 11.0; 3" DR 11.5; 3" DR 11.0	8
> 0.36 to 0.55 (9 to 14)	4" DR 11.0; 4" DR 11.5; 6" DR 13.5	10
> 0.55 to 1.18 (14 to 30)	6", 8", 10", 12" DR's 11.0; 11.5; 13.5	15
> 1.18 to 2.5 (30 to 64)		20
> 2.5 to 4.5 (64 to 114)		25

To calculate for Wall Thickness, divide Actual Pipe OD by DR. Wall thickness values are also given in Performance Pipe Size and Dimension Charts.

➔ ***Important:*** The maximum heater plate removal time for ½ in. CTS to 1 ½ in. IPS is 4 seconds.

➔ ***Important*:** For 14" and larger pipes, a minimum heat soak time of 4.5 minutes per inch of pipe wall thickness and the minimum melt bead size must be achieved.

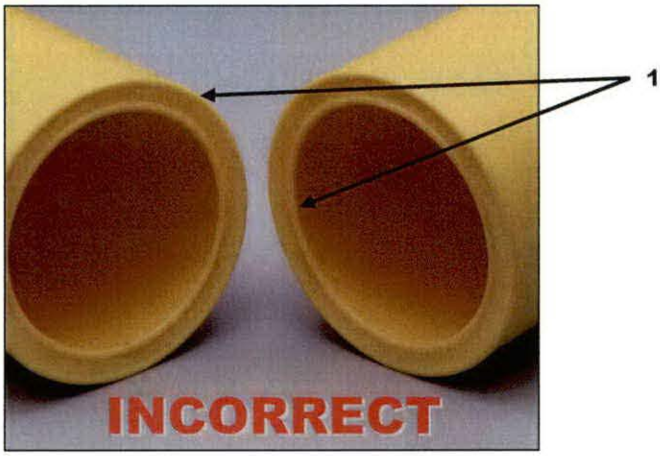
During heating, the melt bead will expand out flush to the heating tool surface or may curl slightly away from the surface. If the melt bead curls significantly away from the heating tool surface, unacceptable pressure during heating may be indicated.

5. ***Join.*** Immediately after heating tool removal, ***quickly*** inspect the melted ends, which should be flat, smooth and completely melted. If the melt surfaces are acceptable, immediately and in a continuous motion, bring the ends together and apply the correct joining force. ***Do not slam. Apply enough joining force to roll both melt beads over to the pipe surface***.

   A concave melt surface is unacceptable; it indicates pressure during heating. See **Figure 1**. Do not continue. Allow the component ends to cool and start over at Step 1.

Figure 1

Unacceptable Concave Melt Appearance



- The correct joining force will form a double bead that is rolled over to the surface on both ends.

6. ***Hold.*** Hold joining force against the ends until the joint is cool. Maintain fusion pressure against the pipe ends at a minimum cool time rate of 11 minutes per inch of pipe wall thickness. **For ambient temperatures above 100°F, additional cooling time may be needed. *Do not try to shorten cooling time by applying water, wet cloths or the like*.**
   - Avoid pulling, installation, pressure testing and rough handling for at least an additional 30 minutes after removal from the fusion machine. For 1" IPS and smaller pipe sizes, only 10 minutes of additional cooling time is required.
   - Heavier wall thickness pipes require longer cooling times.

7. ***Inspect.*** On both sides, the double bead should be rolled over to the surface and be uniformly rounded and consistent in size all around the joint. Butt fusion bead dimensional guidelines can be seen in **Figure 2**.
   - **When butt fusing to molded fittings, the fitting-side bead may have an irregular appearance due to the molded part cooling and knit lines. This is acceptable provided the pipe-side bead is correct.**
   - **One bead may be larger than the other when fusing two dissimilar materials. This is acceptable provided both bead sizes are uniform around their respective pipes.**
   - **It is not necessary for the internal bead to roll over to the inside surface of the pipe.**

Figure 2

Butt Fusion Bead Proportions (ASTM F2620)

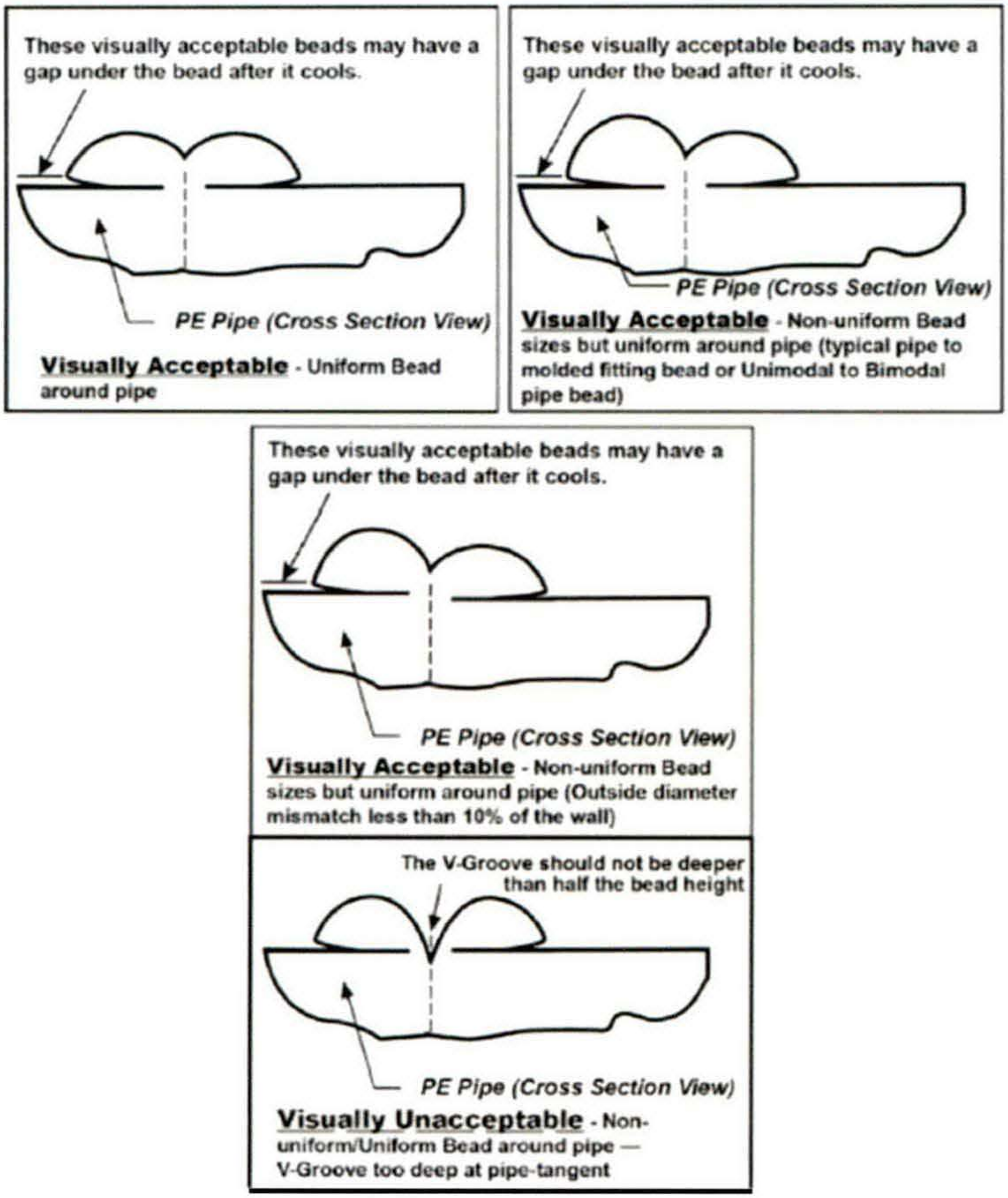
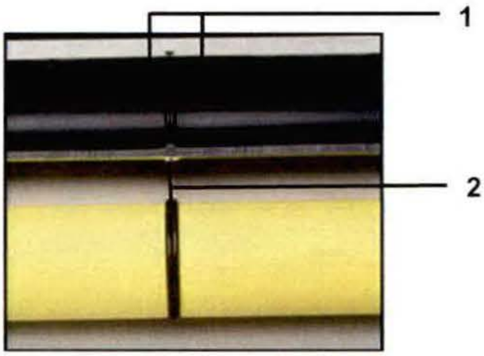


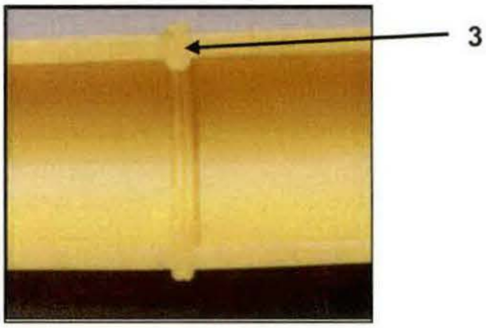
Table 3: Butt Fusion Bead Troubleshooting Guide

Observed Condition	*Possible Causes*
Double bead v-groove too deep	Pressure applied during the heating cycle.
Non-uniform bead size around pipe	Misalignment; defective heating tool; worn equipment; incomplete facing
One bead larger than the other	Different bead sizes are expected when joining different material types, such as heat fusion joining MDPE to HDPE pipes. If the two materials being joined are the same, then having one bead being larger than the other bead may be a sign that the component slipped in clamp; that the heating tool may be defective or that there may be incomplete facing;
Beads too small	Insufficient heating; insufficient joining force
Beads too large	Excessive heating time
Rough, sandpaper-like, bubbly, or pockmarked melt bead surface	Hydrocarbon contamination

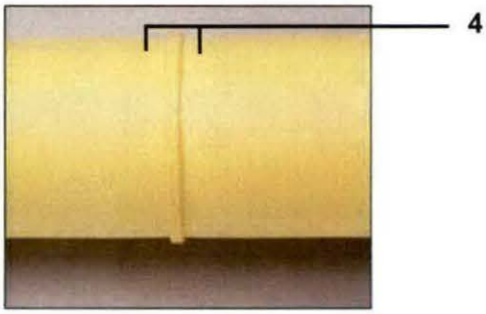
Acceptable Fusions



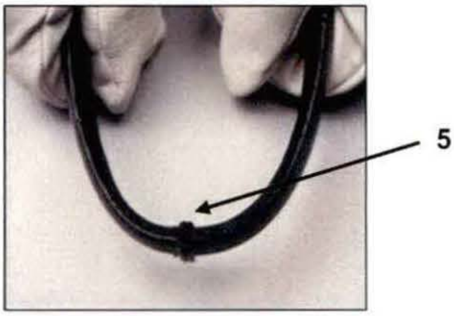
1. Proper double roll-back bead
2. Proper alignment



3. Proper double roll-back bead

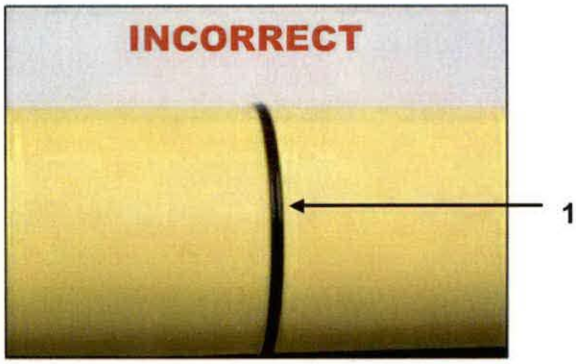


4. Proper alignment

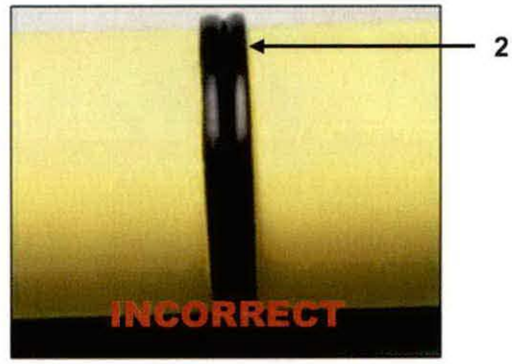


5. No gaps or voids when bent

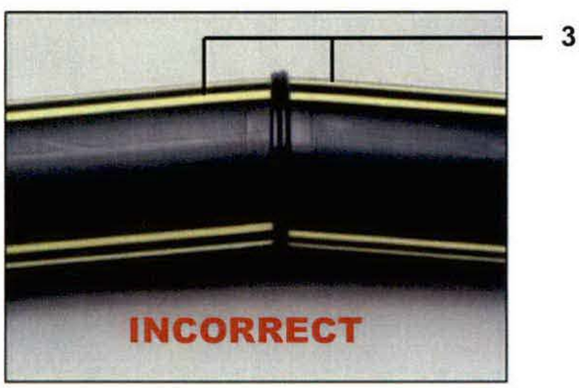
Unacceptable Fusions



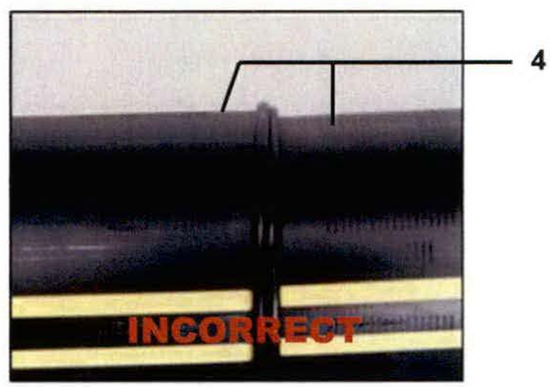
1. Insufficient heat time; melt bead too small



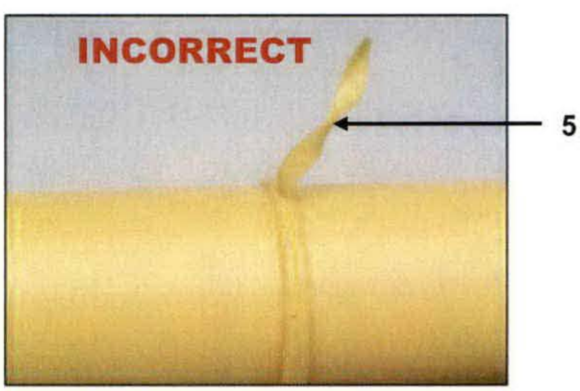
2. Excessive heat time or pressure applies during heating; melt bead too large



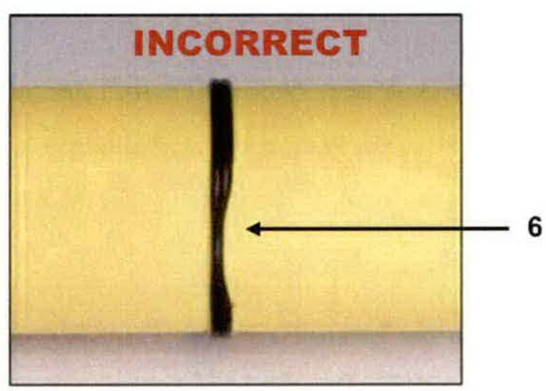
3. Pipe angled into fusion unit



4. Improper "High-Low" alignment



5. Incomplete face off or failure to remove faced off ribbons



6. Incomplete face off

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BEND BACK TESTING OF BUTT FUSED JOINTS

FOR GAS UTILITIES, REFER TO DOT CFR 192.285 FOR QUALIFYING PERSONS TO MAKE JOINTS.

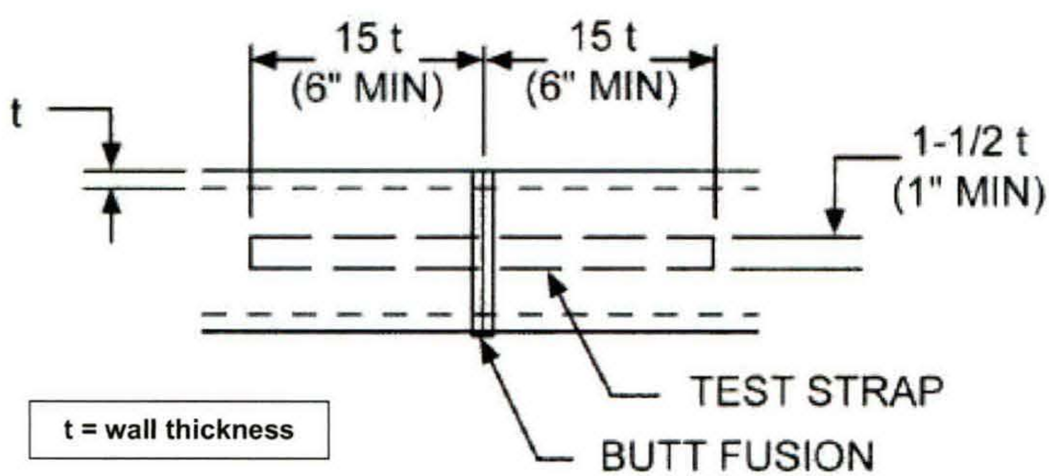
1. Prepare and cut joint samples into test straps. For these qualifying procedures, limit the joint samples to pipe wall thickness of no greater than 1 in. (25 mm). Please refer to **Figure 3** below.

◆ ***WARNING – Bend testing of pipes with a wall thickness greater than 1 in. (25 mm) can be dangerous and should be done with an approved bending fixture that supports and contains the pipe during testing.***

2. Visually inspect the cut joint for any indications of voids, gaps, misalignment of surfaces that have not been properly bonded during the fusion process.
3. Bend each sample at the fusion joint with the inside of the pipe facing out until the ends touch. The inside bend radius should be less than the minimum wall thickness of the pipe. The sample joint must be free of cracks and separations within the fusion joint zone.
4. Repeat Steps 1-3 if failure does occur at the weld in any of the samples.

Figure 3

Butt Bent Strap Test Specimen



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SADDLE FUSION

SADDLE FUSION TO A PRESSURIZED MAIN (HOT TAPPING)

As identified in the introduction, this saddle fusion procedure applies to field fusion of Performance Pipe service saddles, tapping tees and branch saddles.

◆ ***WARNING: The possibility of gas main blowout increases when internal pressure is higher, when the pipe wall is thinner (higher DR) and when the temperature of the main is elevated.***

When saddle fusing to a pressurized gas main, gas main internal pressure must not exceed pressure limits specified in Federal regulations (MAOP).

- For Federally regulated gas applications in the United States, main pressure must be reduced for elevated temperature when the main temperature exceeds 100°F (38°C).
- For Federally regulated gas applications in Canada, main pressure must be reduced for elevated temperature when the main temperature exceeds 23°C (73°F).

Saddle fusion to pressurized gas mains is not recommended for 3" IPS (89mm) mains with DR's above 13.5 and 4" IPS (110 mm) and larger mains with DR's above 17.

REQUIRED EQUIPMENT

✓ A saddle fusion machine (application tool/unit) with appropriate clamps for the main pipe and saddle fitting. Use a main bolster or support for 6" IPS (160 mm) and smaller main pipes.

➔ ***Important:*** When saddle fusing to a pressurized main, the saddle fusion machine must have a gauge or mechanism that indicates the force applied when the saddle base is pressed against the heating tool or the main.

✓ A heating tool with faces contoured and correctly sized for the main pipe and the fitting base. Both serrated and smooth heater faces will produce quality saddle fusions with the serrated heater faces being preferred.

✓ 50-60 grit utility cloth.

✓ Timing equipment such as a stopwatch or watch with a sweep second hand when fusing to 2" IPS and smaller mains.

◆ ***WARNING: Using improper or faulty equipment, or failing to follow correct saddle fusion procedure during saddle fusion to a pressurized main can result in death, serious injury or property damage.***

➔ ***Important:*** Saddle fusion machines, tools and equipment from different manufacturers will operate differently. Follow the machine manufacturer's instructions for proper use and operation of the equipment.

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SET-UP PARAMETERS

HEATING TOOL SURFACE TEMPERATURE - MINIMUM 490°F – MAXIMUM 510°F (255–265°C)

Low heating tool temperature can lead to a blowout during saddle fusion to a pressurized main. Before you begin, all points on both heating tool surfaces must be within the prescribed minimum and maximum temperatures where the heating tool surfaces will contact the main or the fitting. Heating tool surfaces must be clean.

SADDLE FUSION PARAMETERS

➔ ***Important:*** Saddle fusion bead-up force, heating force and joining force are printed on the fitting label and can be found in the Performance Pipe fusion force document online.

Bead-Up Force. During bead-up, force is applied to form an initial melt pattern on the main and the fitting base. Bead-up ends when melt is visible at the top center of the main on both sides of the heating tool. Bead-up force is usually applied for 3 – 5 seconds, but no more than about 1/3 of the total heating time. The bead-up force in pounds is the first number (XXX) on the fitting label. See **Figure 4**.

Heating Force. The heating force is always zero. During heating, the fitting, heating tool and main are held together, but without applying force. The heating force is the second number on the fitting label (as depicted in **Figure 4** as "0").

Joining Force. Joining force is applied to the fitting against the main immediately after the heating tool is removed. Joining force is half the bead-up force. The joining force is the third number (ZZZ) on the fitting label. See **Figure 4**. Joining force must be maintained for the duration of the first cooling time period.

❖ ***Caution – Never reduce joining force during the first cooling time period. Reducing joining force during the first cooling time period may result in blowout during hot tapping.***

➢ If the saddle fusion machine force gauge reading rises during the minimum cooling time period, allow it to do so, see **Step 4** of the Saddle Fusion Procedure section for minimum cooling time.

Maximum Heating Time. Heating time starts when the heating tool is first applied to the main. Heating time ends when the heating tool is removed from in-between the main and the fitting. When hot tapping 2" IPS and smaller mains, a timing device such as a stopwatch or watch with a sweep second hand is necessary for measuring heating time. See **Table 4** for Maximum Heating Time.

◆ ***WARNING – When saddle fusing to a pressurized main, blowout may occur if maximum heating time is exceeded.***

Minimum Cooling Time. Cooling time is two successive cooling time periods. During the first cooling time period, joining force is applied with the saddle fusion equipment. At the end of the first cooling time period, the application tool may be removed. During the second time period, the joint must be allowed to cool undisturbed. After the second cooling time period, the service or branch line may be connected, or pressure leak tests or tapping may be conducted. See **Step 4** in the procedure for Minimum Cooling Time.

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◆ ***WARNING – Never reduce joining force during the first cooling time period, even if joining force increases on its own.***

Figure 4
Example Fitting Label

DRISCOPLEX DRISCOPLEX™ piping
65M 3" IPS x 1/2" CTS 0.090 RTB BTT 0.50 PS1-12
1050163 AB-CD-EFGH-I
ASTM D2513/D3261 CEE PE2406
Made in the USA XXX/0/ZZZ

PROCEDURE

1. ***Prepare***. The area of the main pipe where the saddle fusion machine and the fitting will be located must be clean, dry and free of deleterious nicks, gouges or cuts[2]. The application tool must fit on the main pipe without interference or restriction from components or appurtenances, fusion beads or the like. Remove dirt and foreign materials from the main pipe surface. If below grade, the excavation must be large enough to install and operate the Saddle Fusion Machine. The main pipe must not be curved tighter than 100 pipe diameters bending radius.

   ◆ ***WARNING – Observe all applicable codes, regulations and safety precautions when working in trenches or other excavations and when working with pressurized gas lines.***

   - Install the saddle application tool on the main pipe according to the tool manufacturer's instructions. The saddle application tool should be centered at the location where the fitting will be fused.
   - Abrade the fusion surface of the fitting base and the mating fusion surface of the main pipe with 50-60 grit utility cloth. On the main surface, abrade a surface area that is the size of the fitting base plus about 1/2-in (13 mm) per side all around. It is necessary to completely remove a thin layer of material from both surfaces. After abrading, brush the residue away with a clean, dry cloth. Do not touch abraded and cleaned surfaces with your hands.
   - Regular replacement of the utility cloth is necessary. Worn or dirty utility cloth will not abrade the surface properly. Poor surface preparation can cause poor fusion quality.
   - Install and lightly clamp the fitting in the saddle application tool. (Tapping tee caps may need tightening.) Move the fitting base against the main pipe and apply moderate force (around 100 lbs) to seat the fitting against the main pipe and in the application tool. It may be necessary to wiggle the fitting a little to be sure it is completely seated and squarely aligned against the main. While maintaining force, secure the fitting in the saddle application tool. Move the fitting away from the main pipe.

[2] If used, alcohol wipes are used only before abrading the surface, never after abrading the surface. The surface should be wiped dry with a clean, dry non-synthetic (cotton) cloth or paper towel after using the alcohol wipe.

2. ***Heat.*** Verify that the heating tool is between 490°F - 510°F. Place the heating tool on the pipe centered beneath the fitting base and immediately lower the fitting against the heater face. **Do not slam** the fitting against the heating tool. Quickly apply the calculated Initial heat force and begin timing. At the first visual indication of melt between heating tool face and the crown of the pipe, reduce force to heat soak force (zero force) and continue timing. Heat the pipe and fitting until the indicated total heating time expires or a melt bead of 1/16" is visible around the fitting base. See **Table 4.**

   ➔ ***Important: Use a Flexible Heat Shield for large fittings (>IPS 3" outlet) and large mains (>IPS 6")***

   - A Flexible Heat Shield prevents the fitting from overheating while heating a thick main pipe.
   - Place the heating tool on the main centered beneath the fitting base, and then place the Flexible Heat Shield between the heating tool and fitting base. (It may be necessary to have an assistant handle the Heat Shield.)
   - Apply initial heat force, then when a melt bead is first visible on the main all around the heating tool faces, release the initial heat force, raise the fitting slightly, remove the Heat Shield, move the fitting against the heating tool face, apply initial heat force and start the heat time. When a melt bead is first visible all around the fitting base (usually about 3 to 5 seconds), reduce to heat soak force (zero). Maintain heat soak force until a 1/16 inch bead is present around the fitting base.

   ◆ ***WARNING – Heating and fusing must be performed accurately and quickly, especially when saddle fusing to a pressurized main pipe. Overheating or excessive time between actions can cause a blowout.***

   ◆ ***WARNING – Do not interrupt heating to inspect the melt pattern on the main pipe. When fusing to a pressurized main, this can overheat the main pipe and cause a blowout.***

3. ***Join.*** When the heating time ends, separate the heating tool from the fitting and the pipe and remove the heating tool. Quickly inspect the melt on the pipe and fitting base. Within 3 seconds move the fitting against the pipe and apply the calculated fusion force.

4. ***Hold.*** Maintain the fusion force for 5 minutes on IPS 1¼" (42 mm) and for 10 minutes on larger sizes. Cool undisturbed for an additional 30 minutes. During this time avoid pressure testing, rough handling, tapping and connecting to the branch outlet.

   ◆ ***WARNING – Blowout – Always join the fitting to a pressurized main pipe after heating. If the fitting is not joined to the main pipe immediately after heating, the pressurized main pipe may rupture.***

   - After fusion joining force has been applied, **NEVER** reduce fusion joining force until the first cooling time period has ended. Do not reduce the application tool joining force setting if the value on the application tool gauge rises.

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- The saddle fusion machine may be removed after the first cooling time period has ended.

5. ***Inspect.*** Visually check the fusion bead around the entire fitting base at the main pipe. The fusion bead should be uniformly sized all around the fitting base and should have a characteristic "three-bead" shape. Refer to Image #1 under the Acceptable Fusion section. The first bead is the fitting base melt bead. The second or outermost bead is produced by the edge of the heating tool face on the main. The third or center bead is the main pipe melt bead. The first and third beads should be about the same size all around the fitting base. If the melt on the main pipe or the fitting base was unacceptable, the saddle fusion should not be placed in service. Please see **Table 5** for troubleshooting of irregular bead performance and/or appearance.

Table 4: Saddle Fusion Parameters

Sequence	**Parameter**
Heater Adapter Surface Temperature	500 ± 10°F (260 ± 6°C)
Initial Interfacial Pressure	60 ± 6 psi (4.14 ± 0.41 bar); *Calculate or See Fitting Label*
Heat Soak Interfacial Pressure	0 psi; *Calculate or See Fitting Label*
Fusion Interfacial Pressure	30 ± 3 psi (2.07 ± 0.20 bar); *Calculate or See Fitting Label*
Total Heating Time on Pressure Main – 1-1/4" IPS	15 seconds Max
Total Heating Time on Pressure Main – 2" IPS	25 to 35 seconds Max
Total Heating Time on Non Pressure Main – 1-1/4" and 2" IPS Total Heating Time on Pressure/Non Pressure Main – 3" IPS and Larger	Look for a 1/16 in (1.6 mm) bead around the fitting base

Table 5: Saddle Fusion Bead Troubleshooting Guide

Observed Condition	***Possible Cause***
Non-uniform bead size around fitting base	Misalignment; defective heating tool; loose or contaminated heating tool saddle faces; worn equipment; fitting not secured in application tool; heating tool faces not within specified temperature
One bead larger than the other	Misalignment; component slipped in clamp; worn equipment; defective heating tool; loose or contaminated heating tool saddle faces; heating tool faces not within specified temperature
Beads too small	Insufficient heating; insufficient joining force
Beads too large	Excessive heating time; excessive force
No second bead (or outermost bead)	Incorrect pipe main heating tool face
Serrated bead appearance	Normal for serrated heating tool faces
Smooth bead appearance	Normal for smooth heating tool faces
Pressurized main pipe blowout (beside base or through fitting center)	Overheating; incorrect heating tool faces; heating tool faces not within specified temperature; taking too much time to start heating (Step 2e), or to remove the heating tool and join the fitting to the main pipe (Step 3g);
Rough, sandpaper-like, bubbly, or pockmarked melt bead surface	Hydrocarbon contamination
No third (or center) bead	Insufficient joining force

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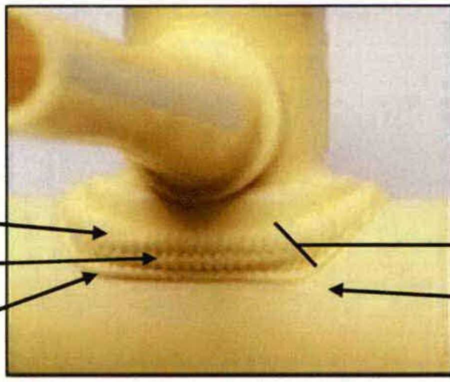
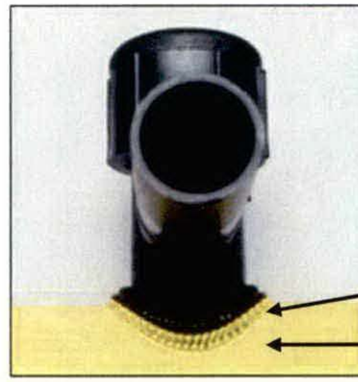
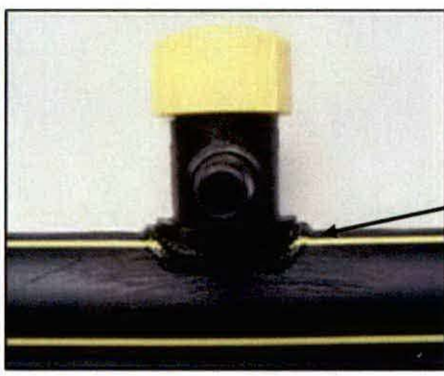
Acceptable Fusions



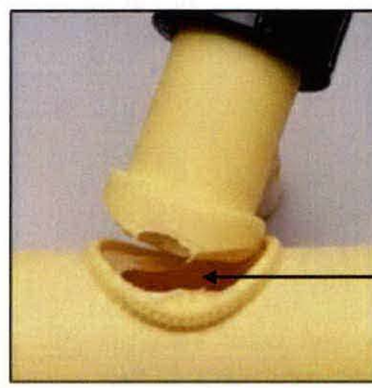
1. Proper alignment, force and melt
2. Proper pipe surface preparation



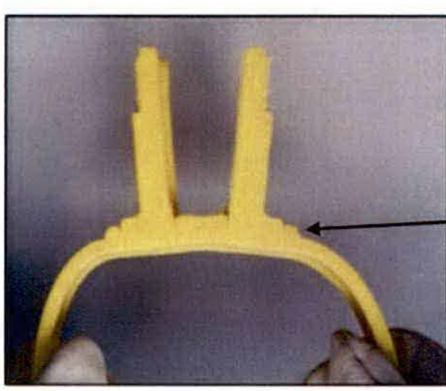
3. Proper alignment, force and melt
4. Proper pipe surface preparation



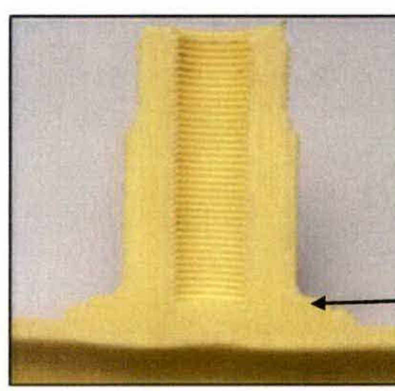
5. Melt bead below or parallel with top of fitting base



6. Material pulled from pipe when impact tested

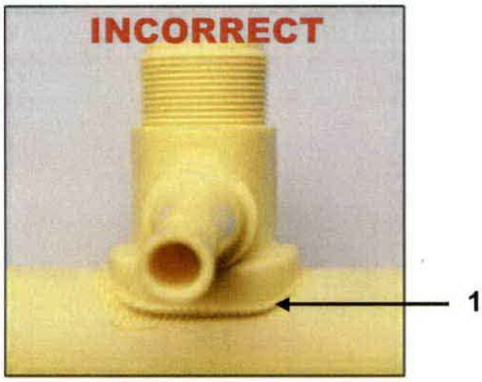


7. No gap or voids when bent

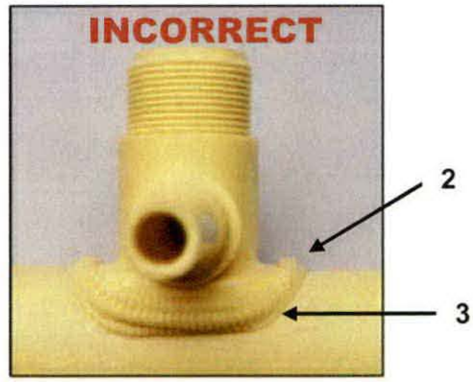


8. No gaps or voids at fusion interface

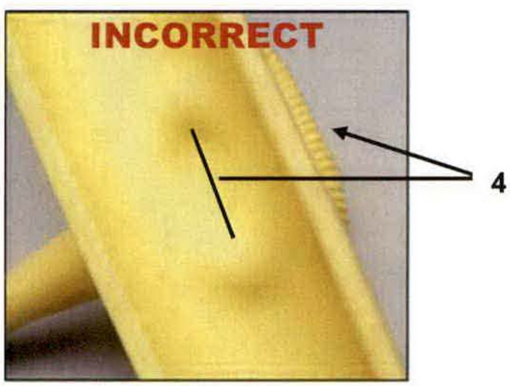
Unacceptable Fusions



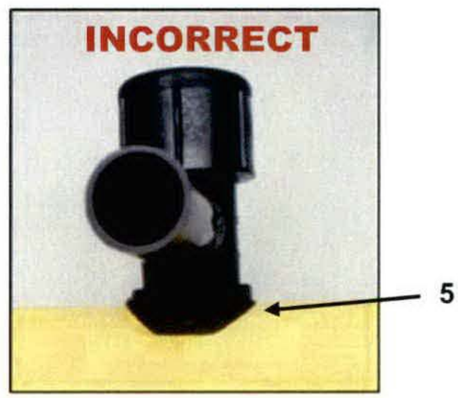
1. Insufficient melt and misaligned



2. Bead above base of fitting
3. Excessive melt and force



4. Excessive melt and force



5. Insufficient melt

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BEND BACK TESTING OF SADDLE FUSED JOINTS

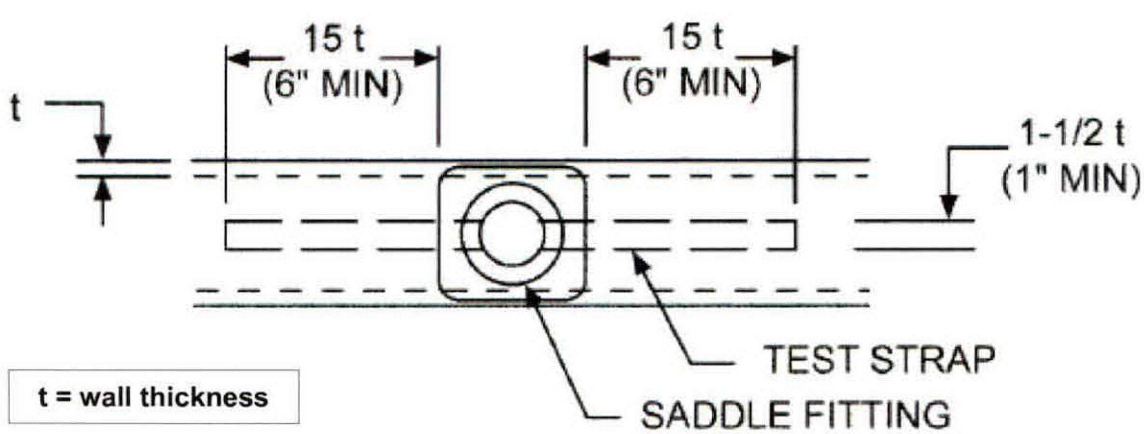
1. Prepare at least two sample joints. The main pipe length should not be less than 2' (610 mm) or seven times the maximum saddle fitting base dimension, whichever is greater. Please refer to **Figure 5** below. Center the fitting on the main pipe length. Observe the joining process to determine that the correct procedure is being followed.
2. Visually inspect the sample joints and compare them to a sample or picture of an acceptable joint.
3. Allow the sample joints to cool for no less than one hour. Do not tap (pierce) the main through the saddle fitting center hole.
4. Cut one sample joint lengthwise along the main pipe and through the saddle fitting to prepare a strap. The cuts should be made near the edge of the fitting center hole so the resulting strap is not quite as wide as the center hole.
5. Visually inspect the cut surface at the joint and compare to a sample or picture of an acceptable joint. There should be no gaps, voids, misalignment or unbonded areas.
6. Bend the strap 180° until the ends touch.
7. If flaws are observed in the sample joints, compare appearance with pictures of unacceptable joints. Prepare new sample joints using correct joining procedure and repeat the qualifying procedure.

Alternate Bend Back Testing of Saddle Fused Joints

Test a sample joint by impact against the saddle fitting. Failure must occur by tearing the fitting or bending the fitting at least 45° or removing a section of wall from the main pipe. Failure along the fusion bond line is not acceptable. (Federal regulations require impact tests for procedure qualification, but not for individual qualification.) Refer to ASTM F905.

Figure 5

Saddle Bent Strap Test Specimen



SOCKET FUSION

REQUIRED EQUIPMENT

This procedure requires: Chamfering tool, depth gauge (some manufacturers combine chamfering tool and depth gauge), cold ring clamp, heating tool with male and female socket faces, and timing equipment (such as a watch with a second hand). Holding tools are desirable for 2" IPS (90 mm OD) and larger pipe and fittings. Clean work gloves are suggested.

✓ Heating tool male and female socket faces should meet ASTM F1056 *Socket Fusion Tools for Use in Socket Fusion Joining Polyethylene Pipe or Tubing and Fittings.*

SET-UP PARAMETERS

HEATING TOOL SURFACE TEMPERATURE - MINIMUM 490°F – MAXIMUM 510°F (255–265°C)

- Where heating tool surfaces will contact the main or the fitting, all points on both heating tool surfaces must be within the prescribed minimum and maximum temperatures before you begin.
- Molten PE material may be cleaned from heating tool faces with a wooden implement such as a tongue depressor. To remove burned or charred material from socket faces, heat the faces, insert a short length of pipe or tubing into the female face and a socket fitting onto the male face. Then unplug the heating iron and let it cool completely. When the pipe or tubing and the fitting are removed from the cold heating tool, the burned or charred material will come off with them.

PROCEDURE

1. ***Clean and Cut.*** Clean the inside and outside of the pipe and fitting with a clean, dry, lint-free cloth or paper towel. Do not touch cleaned surface with your hands. The pipe or tubing end must be squarely cut. If the end is not squarely cut, use a plastic pipe cutter or hand saw and cut the pipe or tubing end squarely.
   - When using a wheel-type pipe cutter, be sure the cutter wheel does not thread down the pipe – cut off all partial cuts before fusion.
   - On larger pipes, toe-in may need to be removed before fusion
2. ***Chamfer.*** For all pipe and tubing sizes, chamfer the end to remove the sharp outer edge on the OD. Remove all burrs from inside of pipe ends. Make sure the pipe or tubing end is clean, dry and free of foreign substances. Wipe with a clean, dry, lint-free cloth or paper towel. Do not touch cleaned surfaces with your hands.
3. ***Round.*** Place the depth gauge snugly over the chamfered end of the pipe and clamp the cold ring clamp on the pipe OD immediately behind the depth gauge. Remove the depth gauge
   - In socket fusion, there is an interference fit between the pipe or tubing and the socket, that is, the socket is slightly smaller than the pipe. They won't fit together cold.
   - Heating tool faces are tapered which produces a tapered melt. Therefore, the pipe or tubing and the fitting will tend to push away from the heating tool during heating and will tend to push apart

when first joined together. It is necessary to hold the pipe and fitting against the heater faces during heating and to hold them together when fusing.

- When using a socket coupling to join coiled pipe, if possible "S" the pipes on either side of the coupling to compensate for coil curvature and make it easier to join the second pipe to the coupling.

4. ***Heat.*** Verify that the heating tool is between 490°F- 510°F. Push the socket fitting onto the male socket face. **DO NOT TWIST.** The socket fitting must bottom out completely and be held against the back surface of the male heater face. Then and only then, push the pipe or tubing end into the female socket face. **DO NOT TWIST**. The cold ring clamp must be completely against the female socket face and held in place. Heating time starts when the cold ring is against the female heater face and when pipe and fitting are fully inserted. Heat the pipe end and the fitting socket for the time required in **Table 6**.

   ➔ ***Important***: For socket fusion joining of medium density to high density, pre-heat the high density component. This pre-heat time can be found by subtracting the shorter heating time (medium density) from the longer heating time (high density). If heating times are within 10% of each other, the longer heating time may be used for both components.[2]

5. ***Join.*** At the end of the heating time, quickly remove the pipe and fitting from the Heating Tool simultaneously using a snap action. **DO NOT TWIST**. Inspect the melt pattern on the pipe and fitting socket. The surfaces should be 100% melted with no cold spots. Within 3 seconds after removing from the heating tool, firmly push the pipe end and the fitting socket straight together, **DO NOT TWIST PIPE OR FITTING**, until the cold ring clamp makes firm contact with the end of the fitting socket.

   ➔ ***Important***: Remove the pipe and the fitting straight out from the heating tool faces. Do not displace the melt. If the pipe or fitting are removed at an angle or twisted, melt can be displaced, and the joint may leak or fail. Grasp the pipe behind the cold ring clamp. Pulling on the cold ring clamp handle can cause slippage or displace the melt.

   - If the melt is not complete, do not continue with the joint. Cut off the melted pipe end, use a new fitting and start over from Step 1. **Do not re-use a melted fitting**. If the melt is correct, continue the joining procedure.

   - Grasp the pipe behind the cold ring clamp. Pushing on the cold ring clamp handle can cause slippage or a crooked joint.

[2] The Guideline for the joining of unlike materials is based on PPI TN-13/2007 General Guidelines for Butt, Saddle, and Socket Fusion of unlike Polyethylene Pipes and Fittings.

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6. ***Hold.*** Hold the pipe and socket fitting firmly together until the **Table 6** cooling time has been met. **DO NOT TWIST PIPE OR FITTING**. For ambient temperatures 100°F and higher, additional cooling time may be needed. Remove the rounding clamp and inspect the end of the socket fitting at the pipe for a complete impression of the rounding clamp in the melt surface. Allow the joint to cool for an additional 5 minutes before exposing the joint to any type of stress (ex: burial, testing or fusing the other end of the fitting, etc.).

   ➔ ***Important:*** Push the pipe and fitting straight together. If joined at an angle or misaligned, the joint may leak or fail.

   - Clean heater faces carefully after each fusion with a wooden implement such as a tongue depressor to remove any molten PE from the male and female socket faces.

7. ***Inspect.*** Inspect the end of the socket fitting at the pipe. There should be a clear impression of the cold ring clamp into the melt ring at the end of the fitting with no visible gaps or voids around the pipe at the socket melt ring. The pipe and fitting should be aligned straight with each other. Use **Table 7** for common socket fusion problems. If flaws are observed in the joint, find the cause of the flaw and repeat the procedures to prepare a new join.

   ➔ ***Important:*** For installation purposes, the pipe bend radius should be kept to 100 times the outside diameter when a socket fusion fitting is present to avoid over stressing the pipe and/or fitting connection

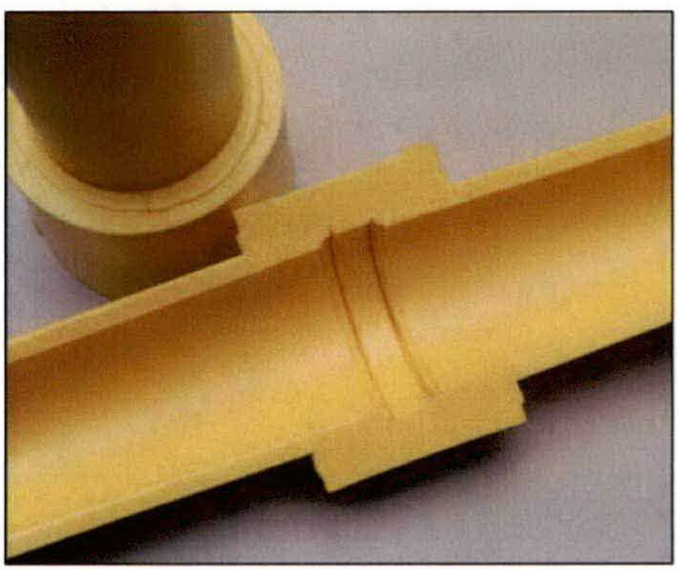
Table 6: Socket Fusion Heating & Cooling Times

Pipe Size	***PE 2406 / PE 2708***		***PE 3408 / PE 3608 / PE 4710***	
	Heating Time, seconds	***Cooling Time, seconds***	***Heating Time, seconds***	***Cooling Time, seconds***
1/2" CTS	6 – 7	30	6 – 10	30
3/4" CTS	6 – 7	30	6 – 10	30
1" CTS	9 – 10	30	9 – 16	30
1-1/4" CTS	10 –12	30	10 – 16	30
1/2" IPS	6 – 7	30	6 – 10	30
3/4" IPS	8 – 10	30	8 – 14	30
1" IPS	10 –12	30	15 – 17	30
1-1/4" IPS	12 –14	45	18 – 21	60
1-1/2" IPS	14 –17	45	20 – 23	60
2" IPS	16 –19	45	24 – 28	60
3" IPS	20 – 24	60	28 – 32	75
4" IPS	24 – 29	60	32 – 37	75

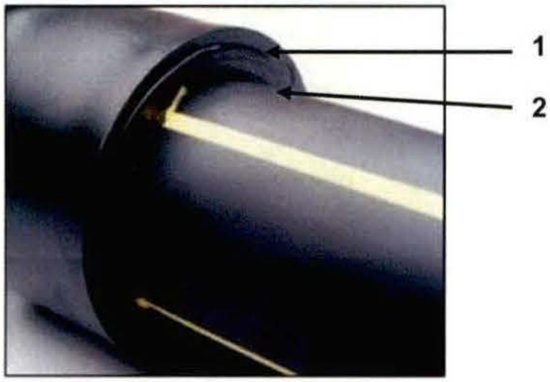
Table 7: Socket Fusion Troubleshooting Guide

Observed Condition	*Possible Cause*
No cold-ring impression in socket fitting melt bead	Depth gauge not used; cold ring not used, or set at incorrect depth; Insufficient heat time
Gaps or voids around pipe at socket fitting edge	Pipe or fitting not removed straight from heater face (twisting or removing from heater face at an angle); pipe or fitting not inserted straight into each other when fusing; Joining together at an angle; twisting while joining pipe and fitting together; cold ring not used or set too deep
Wrinkled or collapsed pipe or tubing end *(when viewed from inside, or when qualifying lengthwise cut joint)*	Incorrect heating sequence – always push the pipe or tubing into the heater ***after*** the fitting has been pushed on the heater (inserting the tubing first heats the tubing too long); cold ring set too deep; cold ring not used
Voids in fusion bond area *(when qualifying lengthwise cut joint)*	Pipe or fitting not removed straight from heater face (twisting or removing from heater face at an angle); pipe or fitting not inserted straight into each other when fusing; joining together at an angle; twisting while joining pipe and fitting together; cold ring not used or set too deep
Unbonded area on pipe or tubing at end of pipe or tubing *(when qualifying lengthwise cut joint)*	Cold ring not used or set too deep
Socket melt extends past end of pipe or tubing *(when qualifying lengthwise cut joint)*	Cold ring set too shallow
Rough, sandpaper-like, bubbly, or pockmarked melt bead surface	Hydrocarbon contamination

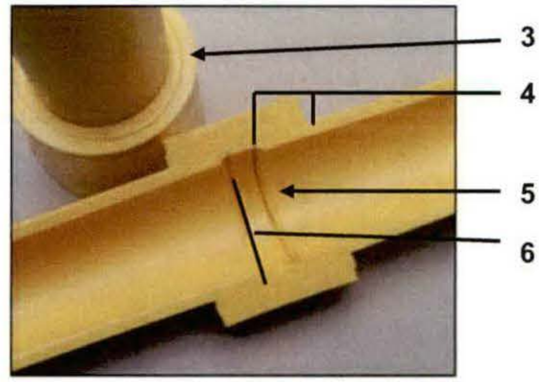
Acceptable Appearance



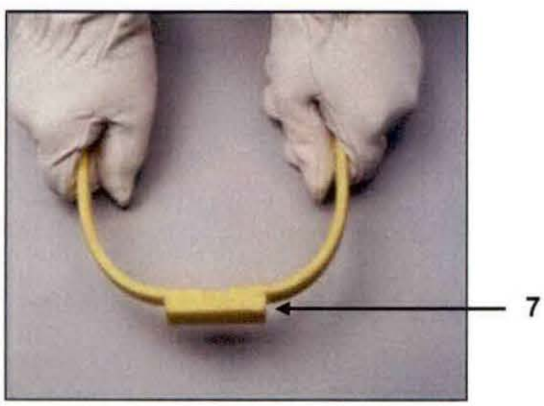
Acceptable Fusions



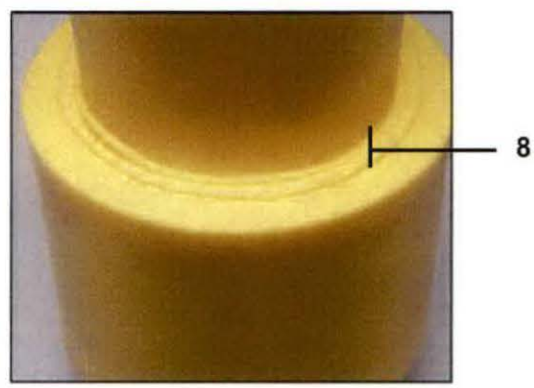
1. Melt bead flattened by cold ring
2. No gaps or voids



3. No gap or voids
4. Proper insertion depth
5. Acceptable internal fusion bead
6. Complete internal melt bead



7. No gap or voids



8. Melt bead flattened by cold ring

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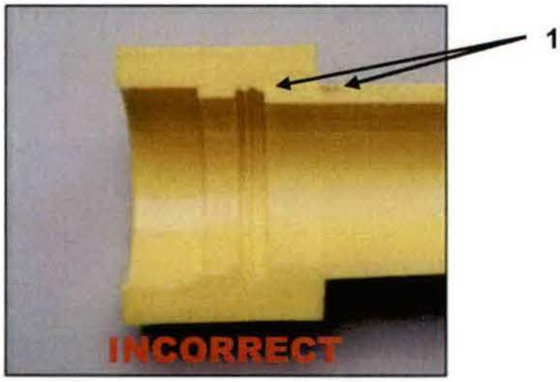
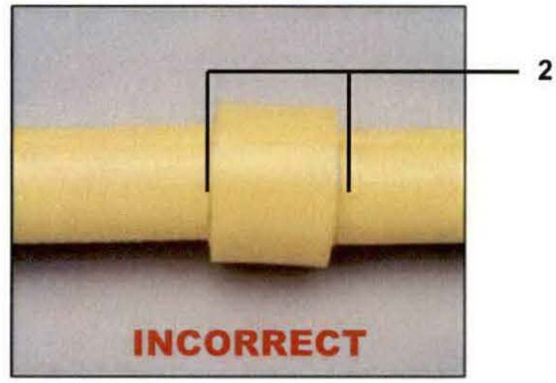
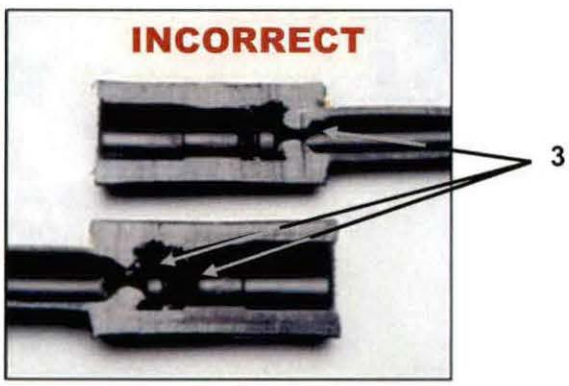
Unacceptable Fusions



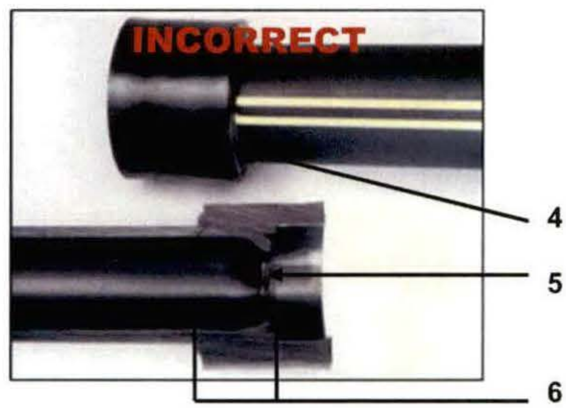
1. Improper insertion depth/short stab depth



2. Misalignment



3. Excessive heating



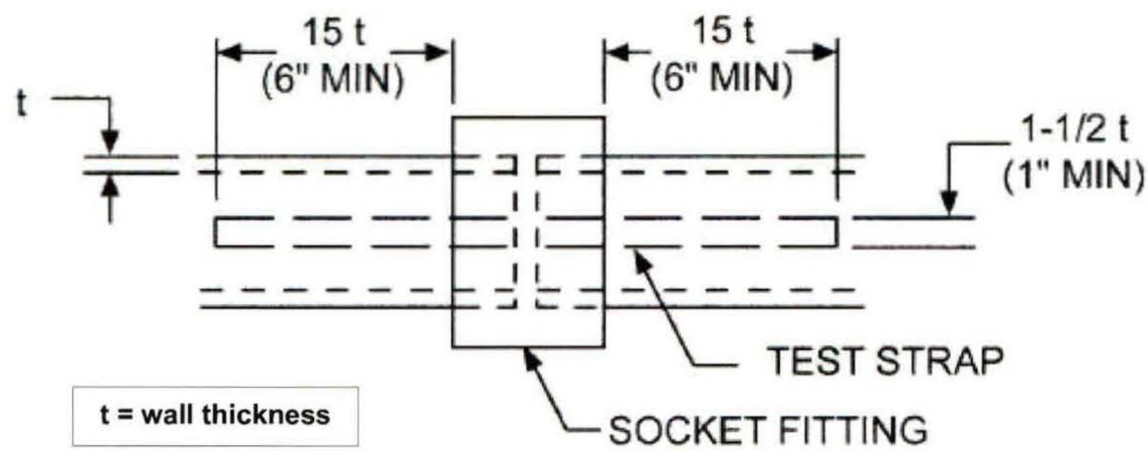
4. Melt bead not flattened against fitting/no cold ring
5. Improper insertion depth/no cold ring
6. Excessive heating

Bend Back Testing of Socket Fused Joints

1. Prepare a sample such as a coupling with pipe or tubing socket fused to both ends. Pipes on either side should be at least 6" (150 mm) or 15 times the wall thickness in length. Please refer to **Figure 6** below. Observe the joining process to determine that the correct procedure is being followed.
2. Visually inspect the sample joint(s) and compare to a sample or picture of an acceptable joint.
3. Allow the sample joint(s) to cool for no less than one hour.
4. Cut the sample joint lengthwise along the pipe into at least three straps that are at about 1" (25 mm) or 1.5 wall thicknesses wide. For sizes less than 2" where this is not possible, the sample may be cut into at least 3 straps with no width requirement.
5. Visually inspect the cut surface at the joint and compare to a sample or picture of an acceptable joint. There should be no gaps, voids, misalignment or unbonded areas.
6. Bend the straps 180 degrees.
7. If flaws are observed in the joint, compare appearance with pictures of unacceptable joints. Prepare a new sample joint using correct joining procedure and repeat the qualifying procedure.

Figure 6

Socket Bent Strap Test Specimen



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Apache Gas Transmission Company, Inc.
2017 Pipeline Replacement Program

Cliff Norris Section	
Contract Proposal for Cliff Norris Section Repair includes materials to install 900' of 6" SDR11 Poly	$ 60,000.00
Two additional 6" valves for both ends of the Cliff Norris Section Replacement	516.00
Oversight and assistance	5,400.00
Contingency	3,300.80
Cliff Norris Section Repair Total	**69,216.80**
Doug Lewis B Section	
A & C Communication Corporation Proposal - open and close ditch	17,403.20
Allowance for crushed limestone back fill	2,000.00
751 feet of 6" SDR 11 Poly pipe 800'	4,491.00
One additional 6" valve for the Doug Lewis B Section Replacement	257.94
Other miscellaneous fittings, tracer wire and marker tape	400.00
Fuse and install pipe	5,000.00
Oversight and assistance	2,500.00
Contingency	1,602.61
Doug Lewis B Section Repair Total	**33,654.75**
Allen Creek Road Drainage Ditch Repair	
A & C Communication Corporation Proposal - open and close ditch	3,000.00
Allowance for back fill	400.00
100 feet of 6" SDR 11 Poly pipe	598.00
One additional 6" valve for the this Section Replacement	257.94
Fuse and install pipe and valve	1,000.00
Oversight and assistance	1,000.00
Contingency	326.54
Allen Creek Road Drainage Ditch Repair Total	**6,582.48**
Estimate for Special Counsel Services	10,000.00
Estimate for Consulting Engineer	10,000.00
Total 2017 Pipeline Replacement Project	**$ 129,454.03**

Lake Cumberland Area Development District Estimated Financing Terms

Term: 180 months

Rate: 2.8%

Monthly payment: $881.59

Proposed Charges on Monthly Statements

Approximant Number of Units		dollars per bill	Monthly revenue
Commercial	104	$3.50	364
Residential	177	$3.00	531
			$ 895.00
		times coverage	1.015

Exhibit G

Financial Exhibit Pursuant to 807 KAR 5:001 Section 12(2):

Apache Gas had $5,000,000 or less in gross annual revenue in 2016. No material changes have occurred since the end of the twelve month period. The financial statements for 2016 are not complete at this time. Apache Gas has submitted the income statement and balance sheet for 2015 and will supplement this filing with the 2016 income statement and balance sheet once they have been completed.

Amount and kinds of stock authorized (807 KAR 5:001 Section 12(2)(a)):

- The amount and kind of stock authorized consist of 1,000 shares of common no par value stock.

Amount and kinds of stock issued and outstanding (807 KAR 5:001 Section 12(2)(b)):

- The amount and kinds of stock issued and outstanding consist of eight separate certificates of 10 shares each of common no par value stock for a total of 80 shares outstanding.

Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise (807 KAR 5:001 Section 12(2)(c)):

- There has been no preferred stock issued for this corporation.

A brief description of each mortgage on property of applicant (807 KAR 5:001 Section 12(2)(d)):

- All notes or loans that enjoyed a mortgage on the Apache Gas Transmission lines have been fully paid.

Amount of bonds authorized and amounts issued and related information (807 KAR 5:001 Section 12(2)(e))

- There have been no bonds authorized or issued by this corporation.

Notes outstanding and related information (807 KAR 5:001 Section 12(2)(f))

- There is a note and a miscellaneous account payable that have been on the books for a long time with balances of $10,716 and $12,000 respectively, from companies owned by David Thomas Shirey Jr. No payments have been made on either the note or the account payable since they are basically a wash. Entries have just not been made to remove these from Apache Gas' books.

Other indebtedness and related information (807 KAR 5:001 Section 12(2)(g))

- There is an outstanding balance on an Elan Visa credit card with a balance of approximately $19,000. This card has been used for operating expenses from time to time. We typically pay the balance down in the winter and Spring and use funds in the summer and fall when revenues are lower. Currently the interest rate is 22.24%. Approximately $2,983.71 was paid in 2016 as interest on this credit card.

Dividend information (807 KAR 5:001 Section 12(2)(h))

Apache Gas Transmission Company issued its first dividend for FYE 12-31-2015 in the amount of $1,000.

Detailed Income Statement and Balance Sheet (807 KAR 5:001 Section 12(2)(i))

See pages 3 through 6 of this Exhibit.

APACHE GAS TRANSMISSION COMPANY, INC.
Balance Sheet
As of December 31, 2015

	Dec 31, 15
ASSETS	
Current Assets	
Checking/Savings	
13101 · Alliance Bank	-209.96
13104 · ALLIANCE BANK - RESTRICTED	676.66
Total Checking/Savings	466.70
Total 1201 · Accounts Receivable	28,573.42
Total Accounts Receivable	28,573.42
Other Current Assets	
141 · Albany Gas - Loan	3,279.81
165 · Prepayments	664.00
Total Other Current Assets	3,943.81
Total Current Assets	32,983.93
Fixed Assets	
100 · UTILITY PLANT	
101 · TRANSMISSION LINE	141,934.58
101.369 · Meas & Reg Station Equipment	53,626.95
110 · ACCUMULATED DEPRECIATION	-136,901.00
Total 100 · UTILITY PLANT	58,660.53
Total Fixed Assets	58,660.53
Other Assets	
190 · ORGANIZATION COSTS	7,500.00
195 · ACCUMULATED AMORTIZATION	-7,500.00
Total Other Assets	0.00
TOTAL ASSETS	91,644.46
LIABILITIES & EQUITY	
Liabilities	
Current Liabilities	
Accounts Payable	
232 · Accounts Payable	656.59
Total Accounts Payable	656.59
Other Current Liabilities	
233 · NOTES PAYABLE	
23304 · Notes Payable - Other	10,716.00
Total 233 · NOTES PAYABLE	10,716.00
234 · A/P	
23307 · Monticello Banking Credit Card	19,322.31
23403 · A/P - Other	12,000.00
23406 · A/P Burkesville Gas	6,324.33
Total 234 · A/P	37,646.64
Total Other Current Liabilities	48,362.64

APACHE GAS TRANSMISSION COMPANY, INC.
Balance Sheet
As of December 31, 2015

	Dec 31, 15
Total Current Liabilities	49,019.23
Total Liabilities	49,019.23
Equity	
201 · COMMON CAPITAL STOCK	1,200.00
216 · Retained Earnings	38,762.34
Net Income	2,662.89
Total Equity	42,625.23
TOTAL LIABILITIES & EQUITY	91,644.46

APACHE GAS TRANSMISSION COMPANY, INC.
Profit & Loss
January through December 2015

	Jan - Dec 15
Ordinary Income/Expense	
Income	
TRANSMISSION OF GAS	
480 · FEES	107,605.09
Total TRANSMISSION OF GAS	107,605.09
Total Income	107,605.09
Expense	
DEPRECIATION & TAXES	
403 · Depreciation Expense	5,800.00
408 · TAXES OTHER THAN INCOME	
40801 · State	365.00
40805 · Property	6,208.89
Total 408 · TAXES OTHER THAN INCOME	6,573.89
409 · OP & NON-OP INCOME TAXES PAYABL	
409.1 · Income Taxes - State & Federal	646.00
Total 409 · OP & NON-OP INCOME TAXES PAYABL	646.00
Total DEPRECIATION & TAXES	13,019.89
GAS OPERATION & MAINT EXP	
MAINTENANCE	
767 · MAINT. OF LINES	34,473.73
Total MAINTENANCE	34,473.73
TRANSMISSION EXP - OPERATION	
860 · Rents - General	7,125.04
Total TRANSMISSION EXP - OPERATION	7,125.04
921 · OFFICE SUPPLIES & EXPENSES	
92101 · Bank Service Charges	173.14
92102 · Dues and Subscriptions	151.92
92103 · Office Supplies	175.00
92106 · Office Expenses	460.50
92107 · Service Fees	156.00
Total 921 · OFFICE SUPPLIES & EXPENSES	1,116.56
923 · OUTSIDE SERVICES EMPLOYED	
92301 · Accounting	2,708.00
92302 · Legal Fees	297.50
92303 · Management Fee	30,000.00
Total 923 · OUTSIDE SERVICES EMPLOYED	33,005.50
925 · INJURIES & DAMAGES (INSURANCE)	
92501 · General Liability Insurance	3,403.07
Total 925 · INJURIES & DAMAGES (INSURANCE)	3,403.07
930.2 · MISCELLANEOUS GENERAL EXPENSES	
930.30 · Telephone	21.25
Total 930.2 · MISCELLANEOUS GENERAL EXPENSES	21.25
933 · TRANSPORTATION EXPENSES	
933.40 · Fuel	1,351.18
Total 933 · TRANSPORTATION EXPENSES	1,351.18

APACHE GAS TRANSMISSION COMPANY, INC.
Profit & Loss
January through December 2015

	Jan - Dec 15
Total GAS OPERATION & MAINT EXP	80,496.33
926 · Employee pensions and benefits	
926.1 · Bonuses	500.00
Total 926 · Employee pensions and benefits	500.00
Total Expense	94,016.22
Net Ordinary Income	13,588.87
Other Income/Expense	
Other Expense	
OTHER DEDUCTIONS	
426 · NONUTILITY DEDUCTIONS	
426.6 · Company Retreat	1,611.07
42601 · Meals	561.92
42602 · Travel	3,786.16
Total 426 · NONUTILITY DEDUCTIONS	5,959.15
Total OTHER DEDUCTIONS	5,959.15
416 · Other Expenses	
Total 416 · Other Expenses	1,122.93
431 · Other Interest Expense	
43101 · Interest - Other than Loan	2,828.60
43102 · Finance Charges	15.30
Total 431 · Other Interest Expense	2,843.90
438 · Divendends Declared-Common Stk	1,000.00
Total Other Expense	10,925.98
Net Other Income	-10,925.98
Net Income	2,662.89

Apache Gas field of operation, description of Apache Gas property, original cost of the property and the cost to Apache Gas:

Apache Gas is in the natural gas transportation business. Apache Gas owns a Spectra Energy/Texas Eastern interconnect and custody transfer station in Metcalf County, Kentucky. Pressure is reduced to not more than 150 psi and transported approximately 3 miles in a 4" steel line to a regulator station. Then pressure is reduced to not more than 100 psi and then transported 15 miles in mostly high density 6" poly gas line although there is approximately 1.6 miles remaining of high density 3" poly gas line to a custody transfer station near the City of Burkesville.

In exchange for a note in the amount of $150,000 in favor of the David Thomas Shirey, Jr. and Kathy Sue Shirey Revocable Trust, Apache Gas Transmission Company was transferred the ownership of the Apache Gas Transmission's gas transmission system substantially as described in the previous paragraph, with the exception of there being originally approximately 5 miles of 3" plastic main instead of the remaining 1.6 miles. Then the note was increased to $588,500 on May 28, 1998 and then reduced to $75,000 on May 31, 1998. The $75,000 note has been paid in full.

To: Burkesville Gas Company, Inc.
From: David Thomas Shirey, Jr., President, Apache Gas Transmission Company, Inc.
Date: April 13, 2017
Subject: Apache Gas Transmission Company Inc.'s Pipeline Replacement Program Rider Tariff

On April 14, 2017, Apache Gas Transmission Company, Inc., ("Apache") will file with the Kentucky Public Service Commission ("PSC"), a new tariff regarding the establishment of a Pipeline Replacement Program ("PRP") to include a monthly surcharge rider. This is a new program so there is no existing surcharge amount on the current monthly bill from Apache to Burkesville Gas Company, Inc. ("Burkesville"). The proposed effective date for the PRP tariff is May 15, 2017.

Apache is proposing the PRP because there are certain sections of Apache's pipeline system in need of repair/replacement. The estimated cost to perform the needed work are too costly for Apache to repair out of its current operating budget. The total surcharge that would be applied under the proposed PRP surcharge to Burkesville's monthly bill from Apache will be $895.00.

Apache received estimates from two different contractors and work will begin as soon as possible after approval by the Kentucky Public Service Commission.

A person may examine this tariff filing at the offices of Apache located at 119 Upper River Street, Burkesville, Kentucky. This tariff filing may also be examined at the offices of the Public Service Commission located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the Commission's Web site at http://psc.ky.gov . Any comments regarding this tariff filing may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602.

The surcharge contained in this notice is the surcharge proposed by Apache but the Public Service Commission may order a surcharge that differs from the proposed surcharge contained in this notice.

A person may submit a timely written request for intervention to the Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication or mailing of the notice, the Commission may take final action on the tariff filing.

NOTICE OF TARIFF FILING OF
BURKESVILLE GAS COMPANY, INC.
TO ESTABLISH A PIPELINE REPLACEMENT RIDER TARIFF
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Pursuant to the Public Service Commission's regulation 807 KAR 5:011, Burkesville Gas Company, Inc. ("Burkesville") gives notice that a tariff filing will be made with the Public Service Commission on April 14, 2017 seeking approval to establish a pipeline replacement rider tariff ("PRP"), to pass through the PRP surcharge from its wholesale gas supplier, Apache Gas Transmission Company, Inc. ("Apache"). If Burkesville's tariff is accepted, the monthly surcharges indicated below will be established for certain rate classes. The PRP surcharges will allow Apache to make needed repairs to its pipeline infrastructure which will be to the benefit of Burkesville's customers. These new PRP surcharges will go into effect May 15, 2017, or sooner if approved by the Public Service Commission.

CURRENT MONTHLY PRP RIDER SURCHARGE:

None

PROPOSED MONTHLY PRP RIDER SURCHAGE:

	Amount	**Percentage**
Residential Customers:	**$3.00/per customer**	**N/A-new charge**
Industrial Customers:	**$3.50/per customer**	**N/A-new charge**

The amount of the proposed surcharge is a flat amount and will not vary based upon a customer's usage. The surcharge rates contained in this notice are the surcharge rates proposed by Burkesville, but the Public Service Commission may order surcharge rates to be charged that differ from the proposed surcharge rates contained in this notice.

Any corporation, association, or person may within thirty (30) days after the date of mailing this notice of the proposed rate change, submit a written request to intervene to the Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request and including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication or mailing of the notice, the commission may take final action on the tariff filing.

Written comments regarding this tariff filing may be submitted to the Public Service Commission through its web site at http://psc.ky.gov/ or mailed to the Public Service Commission at 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602.

Copies of Burkesville's tariff filing may be obtained or viewed at no charge from Burkesville at 119 Upper River Street, Burkesville, Kentucky. The tariff filing and all documents filed with the Public Service Commission may be viewed and downloaded at the Public Service Commission's Web site at http://psc.ky.gov/.

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Apache Gas Transmission Company, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, Approval of Financing Pursuant to KRS 278.300 and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc. for Approval of a Gas Pipeline Replacement Surcharge and Tariff	)	Case No. 2017-________

DIRECT TESTIMONY OF

DAVID THOMAS SHIREY, JR.

ON BEHALF OF

APACHE GAS TRANSMISSION COMPANY, INC. AND

BURKESVILLE GAS COMPANY, INC.

April 14, 2017

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Thomas Shirey, Jr. and my business mailing address is P.O. Box 385, Emory, Texas 75440.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Summit National Holding Corporation. Part of my responsibilities are to provide management services to, and to have oversight of, Burkesville Gas Company, Inc. ("Burkesville Gas").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated in 1981 with a Bachelor of Science Degree in Economics from East Texas State University (currently known as Texas A & M Commerce). From 1984 through 2009, I owned and operated a public finance company. As part of my public finance duties, I successfully planned and completed over two thousand project and equipment financings. These financings ranged from utility system improvements to health and safety equipment and amounted to over four hundred million dollars of funding for small local governments and 501(c)(3) corporations.

Since January 1990, I have been the owner and president of Summit National Holding Corporation, which owns Burkesville Gas. My duties include providing supervisory and management services for a natural gas distribution company (Burkesville Gas). In addition to my management and supervisory services, my natural gas related duties also include direct participation in some of the day-to-day tasks.

I also personally serve as President of an intra-state natural gas pipeline company, Apache Gas Transmission Company, Inc., ("Apache Gas"). In addition to serving as President of Apache Gas, I also participate in some of the day-to-day tasks of the company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will provide general and specific information regarding the need for the Certificate of Public Convenience and Necessity for the Pipeline Replacement Project ("PRP"), the financing for the project and the amount of the surcharge needed for each class of customers to fund the PRP for both Burkesville Gas and Apache Gas.

II. OVERVIEW OF APACHE GAS

Q. PLEASE GENERALLY DESCRIBE APACHE GAS' OPERATIONS.

A. Apache Gas owns a Spectra Energy/Texas Eastern interconnect and custody transfer station in Metcalf County, Kentucky. Pressure is reduced to not more than 150 psi and transported approximately 3 miles in a 4" steel line to a regulator station. Then pressure is reduced to not more than 100 psi and then transported 15 miles in mostly high density 6" poly gas line although there is approximately 1.6 miles remaining of high density 3" poly gas line to a custody transfer station near the City of Burkesville.

Q. WHEN WAS APACHE GAS' LAST NATURAL GAS BASE RATE CASE?

A. The last Apache Gas rate case, Case No. 2007-00354, was filed on August 29, 2007.

Q. PLEASE GIVE AN OVERVIEW OF APACHE GAS' CURRENT NATURAL GAS RATES AND NUMBER OF CUSTOMERS.

A. Apache Gas' current rate is $2.55 per Mcf transported to its only customer Burkesville Gas.

Q. PLEASE GIVE AN OVERVIEW OF BURKESVILLE GAS' CURRENT NATURAL GAS RATES AND NUMBER OF CUSTOMERS.

A. The current rate charged to Burkesville Gas customers has three components. First, it includes a monthly $7.50 per Customer Charge for all customers. Second, the rate includes a Gas Cost Recovery Rate, which as of March 28 2017, was $7.8646 per Mcf for all customers. Last, the current rate includes the Burkesville Gas Commission approved Base Rate of $7.54 per Mcf for Residential customers and $7.19 per Mcf for Industrial customers.

Q. WHAT IS THE PRP INITIATIVE PROPOSED BY APACHE GAS?

A. On July 1, 2013 Apache Gas met with Commission Staff to discuss four areas of pipeline which Apache Gas had discovered were in need of repair on Apache Gas' system. Commission Staff suggested that Apache Gas consider implementing a PRP program pursuant to KRS 278.509. Commission Staff also recommended that Apache Gas request a PSC Staff Opinion regarding Apache Gas' status as a utility and its ability to implement a PRP program pursuant to KRS 278.509.[1] The PSC subsequently conducted an inspection on Apache Gas' system and, in its 2014 Inspection Report, noted these four areas were in need of repair. Since that time, Apache Gas has repaired two of the four areas noted in the 2014 inspection, but the remaining two areas are more difficult and will be more expensive to replace. The two areas that were noted in the 2014 Inspection Report which have been repaired are Doug Lewis Section A and the Spoon Branch Section. The Doug Lewis Section A was 3" high Density polyethylene ("HDPE") and was replaced with 6" HDPE and is approximately 170 feet section. Apache Gas also repaired the Doug Lewis Section C, which was an undersized 3" HDPE pipe, and caused flow restrictions. The Spoon Branch and Doug Lewis C sections were upgraded to 6" HDPE pipe from 3" HDPE pipe,

[1] A copy of Apache Gas' letter requesting a Staff Opinion is attached as Exhibit A and a copy of the PSC Staff Opinion is attached as Exhibit B.

which increased the system's total capacity. The two remaining sections that are in need of repair, as noted in the 2014 Inspection Report, are the Cliff Norris Section and the Doug Lewis Section B. Both of the remaining areas are located in more rural, difficult to access areas, contain more rock content, are on a steeper grade, and are, therefore, more costly to repair. Apache Gas is also proposing to repair the Allen Creek Road Drainage Ditch Section as a part of this PRP. The Allen Creek Road Drainage Ditch Section is currently 3" pipe which crosses a drainage area between two higher grades and has a high percentage of rock. Due to erosion, this section has become exposed. This approximately 100 foot section will be replaced with 6" HDPE pipe.

In 2013, Apache Gas met with Commission Staff to discuss the ability to implement a PRP program pursuant to KRS 278.509. Apache Gas also requested a Staff Opinion regarding Apache Gas' status as a utility and the ability to implement a PRP pursuant to KRS 278.509. A copy of the Staff Opinion is attached to the Application as Exhibit A. The repairs made to date have been made without the implementation of a PRP. However, the remaining repairs are more costly than Apache Gas can make without the implementation of a PRP Program.

III. APACHE GAS' APPLICATION

Q. PLEASE BRIEFLY SUMMARIZE APACHE GAS' APPLICATION AND THE RELIEF REQUESTED IN THIS PROCEEDING.

A Apache Gas is asking the Commission to issue a Certificate of Public Convenience and Necessity ("CPCN") to make certain needed improvements to Apache Gas' gas mains for increased safety and reliability. The existing 3" mains will be replaced with 6" mains in order to improve the total system's capacity. The Application also seeks approval for Apache Gas to enter into a loan to finance the costs of the repairs and to establish a pipeline replacement program rider under KRS 278.509 in order to pay for needed improvements to the Apache Gas system. Even though Apache Gas has been very careful to keep the cost of this project low, the cost of the improvements as described herein are in excess of the Company's total annual gross income.

Q. PLEASE DESCRIBE THE NATURE OF THE PROJECTS REQUIRING A CPCN.

A. Two of the sections were noted in the 2014 PSC Inspection Report. The third, the Allen Creek Road Drainage Ditch crossing, is an area which Apache Gas has recently discovered also needs to be repaired. The specifics of these projects are described more fully in the testimony of Jason Brangers.

Q. IS THERE A NEED FOR THE PROJECTS?

A. Yes. Without completing these projects, Apache Gas will be unable to cure the deficiencies noted in the 2014 Inspection Report. The projects will also make the Apache Gas system more efficient, more reliable and better able to serve new demand.

Q. WILL THE PRP RESULT IN ANY WASTEFUL DUPLICATION OF FACILITIES OR COMPETE WITH ANY OTHER ENTITIES?

A. There will not be wasteful duplication of facilities in connection with these improvements. Apache will only be repairing the existing pipeline or replacing the existing pipeline. In the Doug Lewis Section B repair and in the Allen Creek Road improvements, 3" mains will be replaced with 6" mains that will improve total system capacity. This will aid in providing safe and reliable service as well as other multiple benefits for the consumers. The new facilities will not interfere with any other utility's facilities nor will they present an investment that is in excess of what is required.

Q. EXPLAIN WHY THE COMPANY BELIEVES THAT THE PRP IS NEEDED AT THIS TIME.

A. After the July 1, 2013 meeting, where I was made aware of KRS 278.509 and the PRP option it provides, and after receipt of the August 29, 2013 PSC Staff Opinion stating Apache Gas would be able to seek approval of the PRP option, Apache Gas looked at all needed repairs and the options available. At that time, I decided to make what repairs Apache Gas could make without having to seek a PRP Rider in order to keep rates low for Burkesville Gas' customers. After reviewing the needed repairs, it was determined that the Doug Lewis Section A and the Spoon Branch Sections created the greatest safety risk. Once, I spoke with local contractors regarding the repairs on these two sections, repairs were made. The Doug Lewis Section A and Spoon Branch Sections were less expensive to repair than the remaining two sections, Doug Lewis Section B and Cliff Norris Section. The remaining two sections, are going to be much more costly to repair, based on the terrain and steep grade and the equipment that will be needed to access the pipeline and make the repairs. Therefore, Apache Gas must now apply for a PRP in order to repair and improve the Doug Lewis Section B and the Cliff Norris Section. Apache Gas has received estimates from contractors for these repairs and has attempted to keep these costs as low as possible.

Q. ARE THERE ANY DIRECT PUBLIC/CUSTOMER BENEFITS ASSOCIATED WITH PRP?

A. Yes.

Q. PLEASE EXPLAIN.

A. Apache Gas transports natural gas from the Texas Eastern Pipeline in Metcalf County to a point of delivery near the city of Burkesville, Kentucky. Burkesville Gas then distributes this natural gas to residences, businesses and local governments including: the Cumberland County Hospital, the Cumberland County school system, the Cumberland County Justice Center and Courthouse, 114 Housing Authority units, the City of Burkesville offices, the

Cumberland County Manor and the Cumberland County Library. Repairing and improving Apache Gas' system will in turn provide Burkesville Gas' consumers with safer and more reliable natural gas service.

Q. HOW IS APACHE GAS PROPOSING TO OBTAIN THE UPFRONT FINANCING FOR THE PRP PROJECT?

A. Apache Gas is proposing to obtain financing for the total cost of the project through a loan from the Lake Cumberland Area Development District. Apache Gas feels confident that this loan will be approved by the Lake Cumberland Area Development District, but has also spoken with a local bank, which has financed projects for both Apache Gas and Burkesville Gas in the past. A letter from First and Farmers Bank, is attached to my testimony as Exhibit DTS-1. The interest rate on the Lake Cumberland Area Development District Loan would be a lower rate and would therefore result in a lower monthly surcharge amount to Burkesville Gas and ultimately Burkesville Gas' customers. The monthly surcharge amount collected from Burkesville Gas, and ultimately Burkesville Gas' customers would be used to pay the monthly payment on the loan. If for some reason Apache Gas is not approved for the Lake Cumberland Area Development District Loan, the surcharge amounts may have to be adjusted or the term of the loan lengthened. Currently, Apache Gas is looking at a 180 month term with a 2.8% interest rate from the Lake Cumberland Area Development District.

IV. IMPLEMENTATION OF THE PRP

Q. WHAT AREAS DOES THE COMPANY PROPOSE TO INCLUDE IN THE PRP?

A. For this initial PRP, the capital expenditures and associated costs with the main replacement and improvements to the Doug Lewis Section B Cliff Norris Section and the

Allen Creek Road drainage ditch crossing are included. These sections are discussed in more detail in the Application and in the testimony of Jason Brangers.

Q. **WILL THE COMPANY NEED TO OBTAIN ANY PERMITS FOR CONSTRUCTION OF THE ASRP?**

A. This main replacement project will replace and install the same or better pipe in the same area that the line currently exists for which there are current easements, so no permits are required.

Q. HOW LONG DOES THE COMPANY ANTICIPATE IT WILL TAKE TO COMPLETE ALL OF THE TARGETED REPLACEMENTS?

A. Upon the Commission's approval of Apache Gas' Application for a CPCN, financing and PRP Surcharge Rider and Burkesville Gas' PRP Surcharge Rider, and the closing on the financing to pay for such replacements, I estimate it will take two (2) months for all the replacements to be completed.

Q. WHAT IS THE LAST DATE THAT A COMMISSION ORDER COULD BE ENTERED SUCH THAT THE PROJECT COULD STILL BE COMPLETED IN 2017?

A. Apache Gas would need a Commission Order no later than August 28, 2017. If the Order came after that date, it would be very likely that the repairs would have to be postponed until 2018 due to weather.

Q. WHAT IS THE ESTIMATED COST OF CONSTRUCTION FOR THE PRP PER YEAR AND IN TOTAL?

A. The Total Cost for this Project is estimated to be approximately $130,000 and should be completely spent in 2017. According to the calculations shown in Exhibit F to the Application, the cost per year to Burkesville Gas will be approximately $10,740, which will then be passed on through Burkesville Gas' PRP Surcharge Rider to Burkesville Gas' consumers. The residential customers will see an estimated cost of $36.00 per year from the PRP Surcharge Rider and that industrial customers will see an estimated cost of $42.00 per year.

Q. HOW WERE THESE ESTIMATES DERIVED?

A. The total cost of this project was derived by seeking proposals from utility contractors and from Burkesville Gas, whose employees will be overseeing and aiding in the construction. As a part of the bid process, each contractor and company was required to make a site visit and take measurements so that all associated costs of the project could be contemplated and included in the proposals.

Q. HOW DOES THE COMPANY PROPOSE TO MANAGE THE COSTS OF THE PROGRAM?

A. Because each of the three utility contractors (including Burkesville Gas) were required to make a site visit to take measurements and contemplate all associated costs, and since we have used each of these companies before, I am comfortable the cost estimates are very close to what the actual costs will be. Also, a small contingency amount was added in case any unforeseen costs arose.

V. BURKESVILLE GAS' APPLICATION

Q. PLEASE BRIEFLY SUMMARIZE BURKESVILLE GAS' APPLICATION AND THE RELIEF REQUESTED IN THIS PROCEEDING.

A. Burkesville Gas is requesting permission to pass through the amount of the PRP surcharge rider, that if approved by the Commission, will be billed to Burkesville Gas by its wholesale gas supplier, Apache Gas. Burkesville Gas is requesting that this amount be aggregated to both its Residential and Industrial classes, pursuant to the proposed tariffs that are attached to my testimony as Exhibit DTS-2. Burkesville Gas has attempted to divide the monthly surcharge amount between its customer classes in a way that will have the least amount of financial burden to Burkesville Gas' customers. Based on the calculated estimates, Burkesville Gas' residential customers will be charged $3.00 per month which calculates to $36.00 per year and Burkesville Gas, industrial customers will be charged $3.50 per month which calculates to $42.00 per year.

VI. FILING REQUIREMENT SPONSORED BY WITNESS

Q. WHAT FILING REQUIREMENTS AND EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits and incorporate these into my testimony by reference:

Exhibit DTS-1, the Letter from First and Farmers Bank;

Exhibit DTS-2, the proposed PRP tariffs for both Apache Gas and Burkesville Gas.

Application Exhibits:

Exhibit F, the cost breakdown analysis and proposed PRP surcharge rates;

Exhibit G, the financial exhibits pursuant to 807 KAR 5:001 Section 12;

Exhibit H, the description of Apache Gas' property, its field of operation, the original cost and the cost to Apache Gas;

Exhibit I, the customer notice mailed from Apache Gas to its only customer, Burkesville Gas;

Exhibit J, the customer notice from Burkesville Gas to its retail customers which was published in the Cumberland County News on Wednesday, April 12, 2017 and will be published once a week for three consecutive weeks.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Apache Gas Transmission Company, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc. for a Gas Pipeline Replacement Surcharge	)))))))))	Case No. 2017-________

VERIFICATION OF DAVID THOMAS SHIREY, JR.

~~COMMONWEALTH~~ State OF Texas)
)
COUNTY OF Hunt)

David Thomas Shirey, Jr. President of Apache Gas Transmission Company, Inc., and President of Burkesville Gas Company, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

David Thomas Shirey, Jr.

The foregoing Verification was signed, acknowledged and sworn to before me this 10 day of April, 2017, by David Thomas Shirey, Jr.

ERIN CLARK
Notary Public
State of Texas
ID # 130585213
My Comm. Expires 03-16-2020

Erin Clark
NOTARY PUBLIC, Notary # 130585213
Commission expiration: 3/16/20

FIRST & FARMERS
NATIONAL BANK

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
PO Box 615
Frankfort, KY 40602-0615

To Whom It May Concern,

This letter is addressed to the Public Service Commission concerning our relationship with Burkesville Gas Company and Apache Gas Transmission Company of Burkesville, Kentucky. Both are long-time customers of First & Farmers National Bank. During that time, our relationship with them has been exceptional. They have always done everything we have asked of them. We foster the relationship we have with these companies and will continue to work with them in the years to come. If you should have any questions, please contact myself, Wes Bryant, at 270-384-2361.

Sincerely,

Wes Bryant
AVP/Loan Officer

AREA ALL SERVICE AREAS

PSC KY NO. 1

Original SHEET NO. 3

APACHE GAS TRANSMISSION, INC.

CANCELLING PSC KY NO.

SHEET NO.

RULES & REGULATIONS

PIPELEINE REPLACEMENT PROGRAM (PRP)

Applicable to all utility customers receiving service from Apache Gas Transmission, Inc.

A. CAULCULATION OF PIPELINE REPLACEMENT REIDER SURCHARGE:

The PRP surcharge is based on the annual cost of replacing damaged or exposed pipe on the Apache Gas Transmission's system.

B. PIPELINE REPLACEMENT PROGRAM FACTORS

All customers receiving service from Apache Gas shall be assessed a monthly charge in addition to the Transportation Charge component of their applicable rate schedule that will enable the completion of the pipeline replacement program.

The PRP Rider will be updated annually in order to reflect the impact of net plant additions from pipeline replacements. Such adjustment to the Rider will become effective with meter readings on and after the first billing cycle of June each year, and will reflect allocation of the required increase based on the distribution approved by the Commission.

DATE OF ISSUE April 13, 2017
MONTH / DATE / YEAR

DATE EFFECTIVE May 15, 2017
MONTH / DATE / YEAR

ISSUED BY
SIGNATURE OF OFFICER

TITLE President, Apache Gas Transmission, Inc.

BY AUTHORITY OF ORDER OF THE PUBLIC SERVICE COMMISSION

IN CASE NO. DATED

RULES & REGULATIONS

PIPELEINE REPLACEMENT PROGRAM (PRP)

Applicable to all utility customers receiving service from Burkesville Gas Company, Inc.

A. CAULCULATION OF PIPELINE REPLACEMENT REIDER SURCHARGE:

The PRP surcharge is based on the annual cost of replacing damaged or exposed pipe on the system serving Burkesville Gas customers.

B. PIPELINE REPLACEMENT PROGRAM FACTORS

All customers receiving service from Burkesville Gas shall be assessed a monthly charge in addition to the Customer Charge component of their applicable rate schedule that will enable the completion of the pipeline replacement program.

The PRP Rider will be updated annually in order to reflect the impact of net plant additions from pipeline replacements. Such adjustment to the Rider will become effective with meter readings on and after the first billing cycle of June each year, and will reflect allocation of the required increase based on the distribution approved by the Commission.

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Apache Gas Transmission Company, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, Approval of Financing Pursuant to KRS 278.300 and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc. for Approval of a Gas Pipeline Replacement Surcharge and Tariff	)	Case No. 2017-________

DIRECT TESTIMONY OF

JASON R. BRANGERS

ON BEHALF OF

APACHE GAS TRANSMISSION COMPANY, INC.

April 14, 2017

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason Brangers and my current business address is 817 Taylorsville Road, Shelbyville, KY 40065

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Utility Safety and Design, Inc. (USDI) and I serve in the capacity of Vice President of Operations – KY.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Kentucky with a Bachelor of Science in Civil Engineering in 1995. I was employed by CDP Engineers from 1994-1996, where I served as a rod man, instrument man, and crew chief on various survey crews. I was also responsible for topographic data collection, Alta surveys, boundary surveys, and constructions staking. I also performed deed research and worked on several Corps of Engineer projects, river cross-sections, as well as levee and floodwall topography and stakeout. I also obtained my Engineer in Training (EIT) during this time and was responsible for assisting licensed engineers, performed force main design, road design, lot design and layout, and Computer Aided Drafting (CAD) drawings.

I was employed by MapSync, Inc. from 1996-2004, where I served as a GPS crew member and party chief, as well as obtained my professional engineering license in 2000. I became a certified GPS instructor in 2002, and performed classes each month for utility companies, municipalities, tax assessors, emergency services, government agencies, and private entities. During this time, I also provided technical support, on-site demonstrations, and consulting services to numerous clients. I was project manager for countywide Enhanced 911 projects where I was responsible for managing crews, project coordination, progress reports, data collection, CAD drawings, map production, and final submittals. I also served as project manager for storm and sewer data collection and inventory projects in which drainage studies, facility inventory, and master plans were created.

I was employed by the Kentucky Public Service Commission (PSC) from 2004-2013. From 2004-2005 I served as a Public Service Engineer in the Water/Sewer Branch where I was responsible for leading and managing PSC teams in water and sewer construction cases and preparing and reviewing orders. I also reviewed and evaluated engineering plans and specifications to determine public convenience and necessity and provided engineering support to branch utility investigators on complaints, site-visits, and routine inspections. I inspected construction projects on-site for the purposes of verifying it was as approved by the PSC, assisted in forming team recommendations to the PSC, and consulted with utility representatives, municipalities, and others seeking technical advice pertaining to the PSC's rules and regulations. From 2005-2013, I served as the Public Service Engineer Manager of the Pipeline Safety Branch. Duties there consisted of coordinating and directing all activities related to the natural gas and hazardous liquid pipeline safety program under certification/agreement to the United States Department of Transportation. Responsibilities included grant procurement, federal reporting requirements, and the interpretation and enforcement of state and federal regulations and pipeline safety standards. I supervised four investigators in the inspection, evaluation, and investigation of natural gas and hazardous liquid utility operators in Kentucky to assure compliance with applicable regulations and one engineering technical associate in the review of filings and case work related to construction, complaints, depreciation, tariffs, and the reports and proposed orders associated with such cases. I completed the Leadership P.E. program in 2006 and the Kentucky Certified Public Manager program in 2009. I served as Kentucky's representative to the National Association of Pipeline Safety Representatives (NAPSR), as well as a board member (non-voting position) for Kentucky 811, the state's one-call center, committed to the prevention of damage to underground facilities. I served as the NAPSR Liaison Committee Chairman, NAPSR Data Team Member, NAPSR Southern Vice-Chairman (2010 and 2011), and NAPSR Southern Region Chairman (2012).

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS VP OF OPERATIONS.

A. Since 2013, I have served as VP of Operations for USDI, I am responsible for managing the day-to-day activities and operations of the USDI-Kentucky based office. I currently supervise two (2) employees in performing operation and maintenance tasks for natural gas and landfill gas clients. I also provide and support compliance, operation, and maintenance activities of natural gas and landfill gas operators, including municipalities, local distribution companies (LDCs), transmission, and master meters, through engineering and design, state and federal pipeline safety compliance, plans and manuals development and management, Operator Qualification training and qualification, leak and cathodic protection surveys, regulator station inspections, testing, and rebuilds, odorant testing, and other activities related to gas pipeline safety.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes, I previously testified on behalf of the PSC (i.e. Case 2007-00403).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for the engineering information related to the Application, including the pipeline route description, plans, specifications, and drawings of the proposed pipeline replacement project, filed in the Application as Exhibit D and Exhibit E. Exhibit D is the Plans & Drawings and Exhibit E is the Construction Specifications and Regulatory Requirements. Exhibit D and E also contain the engineering filing requirements for which I am responsible, including 807 KAR 5:001 Section 15(2)(a), (b), (c), (d)(1), (d)(2), and KRS 322.340. These exhibits were prepared by me or someone working under my direct supervision.

II. APACHE GAS TRANSMISSION'S APPLICATION

Q. PLEASE BRIEFLY SUMMARIZE APACHE GAS TRANSMISSION'S APPLICATION AND THE RELIEF REQUESTED IN THIS PROCEEDING.

A. Due to the location and terrain of the Doug Lewis Section B and the Cliff Norris Section, the repair/replacement of these sections is more difficult and costly. These sections are located on steeper grades and the areas contain more rock content that must be appropriately addressed during the construction and installation phase of this project. Apache Gas is requesting a CPCN to include a pipeline replacement program and recovery mechanism to offset the overall cost of the replacement. Apache Gas is a small gas company with annual revenues that simply do not support the expenditures required to complete this project.

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR A CPCN.

A. Apache Gas has approximately 18 miles of transmission line that originates in Metcalf County at its interconnect with Texas Eastern. The transmission line traverses in a southerly and westerly direction, generally, through Metcalf County, into Cumberland County, and terminates near the city of Burkesville, where natural gas is delivered to Burkesville Gas Company, Inc. for distribution through its system. The Apache Gas system is comprised of some steel, but mostly polyethylene (PE) pipe and is routed through rural areas, including some steep slopes and wooded areas as well as open fields, and along various county and local roads. The PE pipeline was exposed in several areas, as noted in the 2014 PSC pipeline safety inspection report. Apache Gas completed the repairs/replacement of two of the four areas noted in the inspection report (the Doug Lewis Section A and Doug Lewis Section C), along with another area known as the Spoon Branch Section. This left the Cliff Norris Section and Doug Lewis Section B to be addressed, both of which are in more rural, rocky areas that are more difficult to access to due to steeper grades and trees. Apache Gas is seeking approval in its CPCN Application to address these two sections through a pipeline replacement program and recovery mechanism, Rider PRP, due to the higher cost and expense of accessing and properly replacing these pipelines. Remediation of the Cliff Norris Section will result in the replacement of approximately 900 feet of 6" pipe with 6" HDPE pipe. Remediation of the Doug Lewis Section B will result in the replacement of approximately 750 feet of 3" pipe with 6" HDPE pipe. Apache Gas has also identified a third area, the Allen Creek Road Drainage Ditch Section, where a small section of pipeline is exposed and needs to be replaced. The Allen Creek Road Drainage Ditch Section is currently a 3" HDPE gas main that crosses a drainage area between two higher slopes. This area typically only has water during a rain, or shortly thereafter, and drains into Allen Creek. However, erosion has caused a short section of pipe to become exposed and should be replaced. Remediation of the Allen Creek Road Drainage Ditch Section will result in the replacement of approximately 100 feet of 3" pipe with 6" HDPE. The replacement of these pipelines is critical for the integrity of the system as they are plastic and have been exposed for a period of time. Exposure of the PE pipeline sections threatens their integrity and leaves them vulnerable to damage from dig-ins, off-road vehicles, vandalism, and rocks, as wells as degradation due to UV exposure. Apache Gas is seeking to repair or replace the exposed natural gas pipeline sections under the Rider PRP, which provides for the recovery of costs not recovered in the existing rates, while improving the safety and integrity of the system.

Q. WILL THE PRP RESULT IN ANY WASTEFUL DUPLICATION OF FACILITIES OR COMPETE WITH ANY OTHER ENTITIES?

A. No, the PRP will not result in any wasteful duplication of facilities or compete with any other similar entities. The proposed project is the replacement of exposed pipe and will not add any additional mileage or territory to the Apache Gas transmission system, whose purpose is to transport gas to the Burkesville Gas Company, Inc. in Burkesville, KY. A review of PHMSAs National Pipeline Mapping System shows no other active natural gas transmission pipelines in Cumberland County and no other active intrastate natural gas transmission pipelines in southern Metcalf County.

IV. IMPLEMENTATION OF THE PRP

Q. WHAT AREAS DOES THE COMPANY PROPOSE TO INCLUDE IN THE PRP?

A. The company proposes to initially include the Cliff Norris Section, Doug Lewis Section B, and Allen Creek Road Drainage Ditch Section in the PRP. If the PRP is approved, the company may opt, at a later date, to include additional pipe sections to replace or upgrade, as deemed appropriate, for the integrity, safety, and reliability of its system. Any additions to the PRP will be filed in Apache Gas' annual reports for PSC approval and a CPCN would be obtained if the improvement did not qualify as an extension of the system in its ordinary course.

Q. HAS THE COMPANY DEVELOPED CONSTRUCTION SPECIFICATIONS TO BE USED IN THE PRP?

A. Yes, construction drawings, specifications, and regulatory requirements were developed and/or referenced for the construction related to the pipeline replacement and PRP. These are included in the Application as Exhibit D (Plans and Drawings) and Exhibit E (Construction Specifications and Regulatory Requirements).

Q. PLEASE EXPLAIN.

A. Included with the company's Application for a CPCN are plans/drawings of the three sections to be replaced, see Exhibit D. Included on each of the section drawings are plan and profile layouts for the new pipeline. Also included are general notes, construction notes, and easement notes, along with the materials list and estimated quantities needed. Apache Gas personnel utilized GPS equipment to map the pipeline route to obtain geographic coordinates and elevations. After review of the GPS data and information was completed, I made a site visit and walked each of the three sections in question as well as compared the GPS elevations for accuracy against USGS topographical maps and information. The data provided by Apache Gas was utilized to produce the drawings and depict the pipeline section routes as shown in Exhibit D. Exhibit E contains construction specifications and regulatory requirements that must be performed and/or met, as applicable, in fulfillment of carrying out this project.

Information pertaining to the pipe specifications (6" HDPE, SDR 11) and valve specifications (6" HDPE, SDR 11) is included as an Appendix to the Project Specifications labeled Exhibit E. Pipe and valve specifications meet or exceed the design criteria and maximum allowable operating pressure (MAOP) for this portion of the Apache Gas system.

Q. PLEASE DESCRIBE HOW THE COMPANY WILL EXECUTE AND COMPLETE CONSTRUCTION UNDER THE PRP.

A. The construction will be completed by outside contractors and/or Burkesville Gas personnel, all of whom must be properly qualified and meet the requirements of applicable pipeline safety regulations (i.e. Operator Qualification). It is anticipated, upon PSC approval of this Application, that construction at the Cliff Norris Section will begin within ten (10) days after the contractor receives the notice to proceed from Apache Gas. It is anticipated that construction at the Doug Lewis Section B will commence within 30 days after the contractor receives the notice to proceed from Apache Gas. Construction at the Allen Creek Road Drainage Ditch Section will commence upon completion of the Doug Lewis Section B replacement. At each of the sections, a bypass, if necessary, will be installed along the pipeline to keep gas flowing to Burkesville Gas tap station. Excavation will commence with a trench being dug to appropriate depth in the current right-of-way of Apache Gas. The trench must be wide enough to install the pipe as well as place and compact backfill soils. The trench bottom may undulate, but must support the pipe continuously and be free from ridges, hollows, and lumps. Any significant irregularities must be leveled off and/or filled with compacted embedment backfill. The new pipeline will be joined/fused as necessary and installed in the trench on appropriate base material. The pipe should not be dropped, dumped, pushed, or rolled into the trench, rather, it should be lowered either manually or with appropriate handling equipment. Fusion shall be performed in accordance with applicable regulations as well as pipe and equipment manufacturer specifications. New valves will be installed at each of the three sections and the tie-in to the existing pipeline will be made. The pipe will be backfilled with appropriate and suitable backfill material. Bedding may be necessary to bring the trench bottom to the required pipe grade, level out any irregularities, and ensure uniform support along the pipe length. The backfill shall provide proper support, limiting flexible and lateral pipe deformation, distribute overhead loads, and isolate the pipe from any adverse effects of the final backfill layer. The final backfill layer should be free of large rocks, frozen clods, construction debris and stones. The pipeline and associated appurtenances shall be pressure tested in accordance with 49 CFR 192.513 to ensure discovery of all potentially hazardous leaks in the segment being tested. The test pressure must be at least 150 percent of the maximum operating pressure, but not more than three times the design pressure determined under 49 CFR 192.121. The tie-in fuses shall be leak tested at operating pressure. The pressure test may be conducted post-installation or pretested prior to installation. The line will need to be purged of air and gas reinstated into the line. The bypass, if installed, will also be removed. All of the construction, bypass, joining, pressure testing, backfilling, purging, and other related activities must be done in accordance with applicable pipeline safety regulations, manufacturing specifications, and engineering specifications and drawings. Apache Gas intends to have a representative on-site during the performance of this work to ensure it is being performed properly. Further details can be found in the Application documents filed as Exhibit D (Plans and Drawings) and Exhibit E (Construction Specifications and Regulatory Requirements).

Q. HOW LONG DOES THE COMPANY ANTICIPATE IT WILL TAKE TO COMPLETE ALL OF THE TARGETED REPLACEMENTS?

A. Pending the approval of the Application by the PSC, and based on the contractors proposals to perform the required replacements, it is estimated that it will take approximately two (2) months after the contractor receives the notice to proceed for all of the requested replacements to be completed on the three (3) sections of pipeline (Cliff Norris Section, Doug Lewis Section B, and the Allen Creek Road Drainage Ditch Section)

V. FILING REQUIREMENT SPONSORED BY WITNESS

Q. WERE ATTACHMENTS LABELED "EXHIBIT D" AND "EXHIBIT E" TO THE COMPANY'S APPLICATION PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes, Exhibit D are the Plans & Drawings and Exhibit E are the Construction Specifications and Regulatory Requirements. Exhibit D and E also contain the engineering filing requirements for which I am responsible, including 807 KAR 5:001 Section 15(2)(a), (b), (c), (d)(1), (d)(2), and KRS 322.340.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Apache Gas Transmission Company, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of a Pipeline Replacement Program, and the Application of Apache Gas Transmission Company, Inc., and Burkesville Gas Company, Inc. for a Gas Pipeline Replacement Surcharge	))))))))))	Case No. 2017-______

VERIFICATION OF JASON BRANGERS

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF Shelby)

Jason Brangers, Vice-President of Operations – KY, Utility Safety and Design, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Jason Brangers, P.E.

The foregoing Verification was signed, acknowledged and sworn to before me this 12th day of April, 2017, by Jason Brangers.

NOTARY PUBLIC, Notary # 556870
Commission expiration: 5/12/20