**Report**

**On**

# Assessment of Pipeline Integrity of Kinder-Morgan Conversion Of the Rancho Pipeline

**To**

## City of Austin Texas

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**By**

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# Assessment of Pipeline Integrity of Kinder-Morgan Conversion Of the Rancho Pipeline

## INTRODUCTION

The objective of this study is to conduct an integrity assessment of the Kinder-Morgan conversion of the Rancho pipeline from crude oil to natural gas service. Kinder-Morgan purchased a portion of the Rancho pipeline from TEPPCO to supply natural gas to the City of Austin Sand Hill Power Plant and to eventually serve other facilities in the Austin area. The Rancho pipeline was constructed in 1953 using predominantly 24" by 0.312" and 0.344" wall thickness (with some short sections of heavier wall thickness) API 5LX-52 (52,000 specified minimum yield strength [SMYS]) pipe produced by A. O. Smith Corporation.

This assessment covers the following items:

1. Background information on original pipeline construction,
2. Prior pipeline incidents during operation by Shell and its successors,
3. Conversion actions initiated to comply with 49 CFR Part 192 requirements, integrity assessments performed, remedial actions implemented, and SCADA system modifications,
4. Current operating plans,
5. Potential consequences of incidents,
6. Review of the Sand Hill Lateral to the City of Austin generating station and
7. Recommendations to improve the integrity in operation.

The focus of this study is the Kinder-Morgan Rancho pipeline from Station 15328+16 on the east end (just west of Stony Mont Road) to station 13950+06 on the west end (just west of Fitzhugh Road) a distance of 41.5 miles, see Figure 1. This includes 5 miles on each end that are outside the city limits but within the extra territorial jurisdiction (ETJ) limits of the city of Austin. The route of the Rancho pipeline is shown as a blue line in Figure 1. (The other pipelines in the same corridor are the Williams, Phillips and Koch[1] pipelines shown as red, yellow and green lines respectively.) In addition, in the southeast corner, the Garfield regulator location is located between MLV 8 and the eastern ETJ. The gas supply for the Rancho pipeline is from the southeast to the northwest. The pressure in the line within the Austin ETJ is controlled by the Garfield regulator to a maximum pressure of 676 psig. The gas flows northwest from the regulator to the Sand Hill Lateral to the power plant. Also, within the city and northwest of the Sand Hill Lateral Tap are two deliveries to Texas Gas Service.

It can be observed in Figure 1 that the pipeline is located in an area that has housing developments and thus, this integrity assessment has been initiated by the City of Austin.

[1] The Koch line runs north and south and crosses the Rancho line southeast of the city.

# BACKGROUND INFORMATION ON PRIOR PIPELINE DESIGN AND CONSTRUCTION

The Rancho pipeline was constructed in 1953 and is believed to have been designed, constructed, and operated in accordance with ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids. At the time of the pipeline construction, the B31.4 code was a voluntary code in most states. In 1968, the Office of Pipeline Safety adopted ASME B31.4 as a federal requirement (49 CFR Part 195) and therefore the Rancho pipeline in its later years of service was regulated by 49 CFR Part 195 and the Texas Administrative Code regulated by the Railroad Commission of Texas.

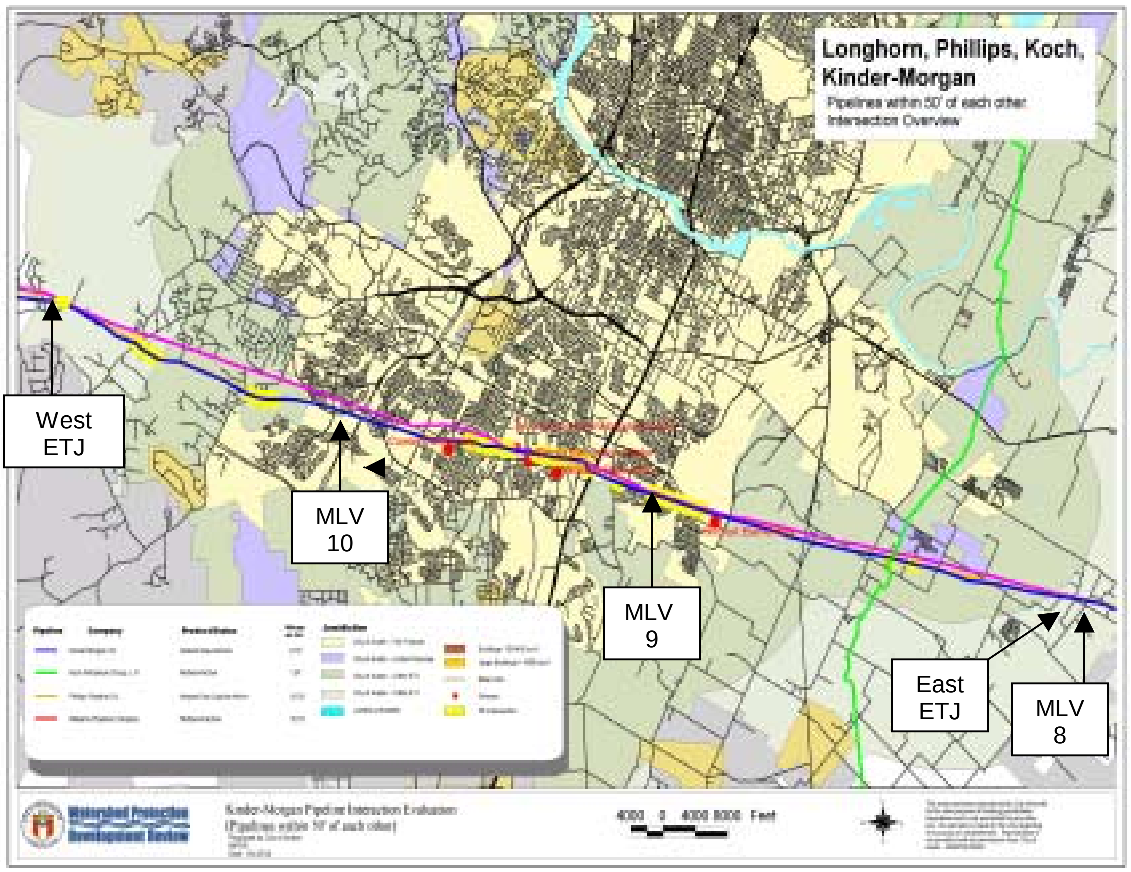


**Figure 1. Location of Kinder-Morgan Rancho Pipeline in the City of Austin.**

The pipeline is composed of 24 inch diameter API 5LX-X52[2] pipe produced by A. O. Smith in 1952 using the electric flash welding process for the longitudinal seam weld. The wall thickness of the pipe is 0.312 inch west of a location approximately 1 mile west of Interstate Highway 35 (Station 14620+00) and from that location east the wall thickness is generally 0.344 inch. Upon detailed examination, there were several instances found where some 0.312 inch wall thickness pipe was located within the 0.344" area. Thus, for evaluation of integrity issues within the Austin ETJ, we have assumed that all of the pipe has a wall thickness of 0.312".

2 The "X52" designates that the specified minimum yield strength (SMYS) of this steel is 52,000 psi.

The electric flash welding process was used from 1930 to 1972. At the time of the production of the pipe involved in this pipeline, the weld seams were not annealed. Flash welding produces a weld seam that is similar to a pre 1970 low frequency electric resistance weld (ERW). The Office of Pipeline Safety (OPS) has issued an alert notice advising that pre 1970 ERW pipe is deemed susceptible to seam failures unless an engineering analysis shows otherwise. As higher strength steels (X60 and higher) were encountered in the late 1960's and early 1970's, the flash welding process for seams experienced problems with the higher strength steels and the A.O.Smith flash weld pipe mills were shut down about 1972.

The pipeline was tested with water in 1953 to pressure levels (stress levels) that ranged from 56 to 83% SMYS (stress levels that are 1.12 to 1.84 times the proposed operating stress level as a natural gas pipeline). Kinder-Morgan has confirmed that no information is available from the previous owner relating to possible failures, or causes of failures, that might have occurred during the original pressure testing of the pipeline.

Four sections of pipe were removed from the pipeline as part of the conversion process. Two of these were 0.312 inch and two were 0.344 inch wall thickness pipes. Tests were conducted by Kinder-Morgan's independent metallurgical laboratory upon our request to determine the mechanical, chemical and fracture toughness characteristics of the pipe steels. Table 1 summarizes the results of the tests.

**Table 1. Rancho Pipe Properties**

| Item | 0.312 inch thickness 14042+00 | 0.312 inch thickness 15737+72 | 0.344 inch thickness 15118+00 | 0.344 inch thickness 15239+00 | API 5LX-Check Requirements -1953 Edition[3] |
|---|---|---|---|---|---|
| **Chemical Composition, percent** | | | | | |
| Carbon | 0.30 | 0.024 | 0.29 | 0.28 | 0.33 |
| Manganese | 0.95 | 0.99 | 1.08 | 1.08 | 1.28 |
| Phosphorus | 0.010 | 0.012 | 0.013 | 0.011 | 0.055 |
| Sulfur | 0.017 | 0.014 | 0.014 | 0.013 | 0.065 |
| Columbium | 0 | 0 | 0 | 0 | NR |
| **Mechanical Properties** | | | | | |
| Yield, Strength, 0.5 % elongation, ksi | 57.9 | 54.4 | 58.9 | 55.3 | 52.0 |
| Tensile Strength, ksi | 87.5 | 80.6 | 87.6 | 88.7 | 66.0 |
| % Elongation, in 2" | 26.0 | 29.0 | 26.0 | 27.0 | NA |
| **Fracture Toughness Properties** | | | | | |
| Charpy Plateau Energy, ft-lbs (2/3) | 20.2 | 20.2 | 22.3 | 25.0 | NR |
| Charpy 85% SATT, F | 82 | 72 | 112 | >110 | NR |

NR, not required; NA, not available, SATT, shear area transition temp.

[3] The pipe involved was reportedly produced in 1952, at which time API 5LX did not provide requirements for an X52 steel. However, it was common in this time period to produce a new grade of steel before it was standardized in API, which appears to be the situation in this instance.

These properties will be used in subsequent sections to assess hydrotest pressure limitations and also critical flaw sizes for leak and rupture. The properties comply with the API requirements introduced in 1953. In addition, the chemical and mechanical properties are in line with the expectations of the authors based on their years of experience in the pipeline industry.

## PRIOR PIPELINE INCIDENTS ON RANCHO PIPELINE DURING OPERATION BY PREVIOUS OWNERS

The prior operating performance of this pipeline provides knowledge of the integrity of the line pipe. Prior incidents associated with the pipe are indicative of the types of problems that may develop in the future. The incidents that have been reported to the Office of Pipeline Safety from 1968 to 2002 were reviewed[4] and ten incidents were found on the Rancho Pipeline as indicated in Table 2. Since this review concerns a conversion from liquid to natural gas, the incidents that are of most interest are those relating to the line pipe. The tank farm problems, pumping station problems and delivery point problems are shown in italics and will be eliminated with the conversion. The three incidents of significance are shown in bold in Table 2. Incident 1 occurred near Houston and involved defective pipe that is believed to have contained a hard spot that failed from hydrogen stress cracking. Incident 5 occurred in Crockett County, which is part of the pipeline that will not be used by Kinder Morgan but it involved external corrosion. Finally, Incident 10 occurred in Travis County and involved outside force damage (mechanical damage from construction equipment). Overall, these operational data incidents suggest that there are three categories of concern identified from the prior operation of the pipeline, which are external corrosion, mechanical damage and hard spots.

**Table 2. Rancho Pipeline Incidents Reported to OPS-1968 to 2002**

| Number | Year | County | City | Incident Involved | Cause |
|---|---|---|---|---|---|
| 1 | **62** | **Harris** | **Pasadena** | **Line Pipe** | **Defective Pipe**[5] |
| 2 | *73* | *Kimble* | *London* | *Pumping Station* | *Other* |
| 3 | *74* | *Upton* | *McCamey* | *Tank Farm* | *Other* |
| 4 | *78* | *Upton* | *McCamey* | *Tank Farm* | *Internal Corrosion* |
| 5 | **82** | **Crockett** | **Big Lake** | **Line Pipe** | **External Corrosion** |
| 6 | *82* | *Fort Bend* | *Missouri City* | *Delivery Point* | *Internal Corrosion* |
| 7 | *83* | *Fort Bend* | *Fulshear* | *Pumping Station* | *Other* |
| 8 | *84* | *Upton* | *McCamey* | *Pumping Station* | *Other* |
| 9 | *85* | *Upton* | *McCamey* | *Pumping Station* | *Other* |
| 10 | **86** | **Travis** | **Oak Hill** | **Line Pipe** | **Outside Force** |

A.O. Smith flash weld pipe has had a history of problems with hydrogen stress cracking[6] in hard spots[7] in the pipe formed during pipe production. This is a concern that has been addressed in

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4 There were no incidents prior to 1968 that were available for this review.

5 This failure is believed to have been caused by a cracked hard spot in the line due to hydrogen stress cracking.

6 Hydrogen stress cracking occurs when atomic hydrogen, generated by the cathodic protection system applied to the pipeline to control corrosion, reaches a critical level in local areas of the steel that were inadvertently hardened in the pipe mill. Fortunately, these local hardened areas can be found with ILI tools.

the conversion of the pipeline. An in line inspection (ILI) was conducted to locate existing hard spots. All of the hard spots found in the ILI are outside of the Austin area and have been mitigated.

## CONVERSION ACTIONS TO COMPLY WITH 49 CFR PART 192 REQUIREMENTS,

The pipeline was designed as a liquid pipeline and therefore did not include Class locations in its design. The pipe was originally designed to a constant design factor[8] of 0.72 indicating that the wall thickness could be constant if no elevation changes existed along the line. Natural gas pipelines have a variable design factor ranging from 0.72 to 0.40 depending on the population density along the pipeline. Also, for natural gas pipelines the location of block or sectionalizing valves is required by federal requirements to be dependent on the Class location rather than controlling the spill as in liquid pipelines. All of the previously installed block valves within the Austin ETJ have been replaced with new, automatic closing valves for quick isolation in the event of a pipeline failure. Automatic closing valves will close automatically when a pressure drop (15 psi in 1 minute) occurs in the line. Automatic closing valves are not required by Part 192 but Kinder-Morgan has elected to install them in minimize the consequences of an incident.

Finally, the SCADA system was modified to account for the change from liquid service to natural gas service. The changes that have been made will be discussed in the following sections.

### Allowable Operating Stress Level

The allowable operating stress level in a natural gas pipeline is regulated by the federal OPS (Office of Pipeline Safety) in Title 49 Part 192 of the Code of Federal Regulations (49 CFR Part 192). The allowable operating stress depends on the population density along the pipeline. Natural gas pipelines are divided into four class locations, with Class locations 1 through 4 respectively allowing a maximum hoop stress in the pipe of 72%, 60%, 50% and 40% SMYS. A Class Location unit is defined as an area that is 660 feet on each side of the pipeline and any continuous one-mile length along the line. The various Class locations are defined in Part 192.5 as:

- Class 1 - has 10 or less buildings intended for human occupancy (in any given rolling mile),
- Class 2 - has >10<46 buildings intended for human occupancy (in any given rolling mile)
- Class 3 - has >46 buildings intended for human occupancy (in any given rolling mile) or has playgrounds, parks, etc in a 330' corridor that is occupied by 20 or more persons at least 5 days a week in any 12 month period, and
- Class 4 - is where buildings with four or more stories above ground are prevalent (i.e. downtown) in the 660 foot corridor. (There is no descriptor in class 4 for more houses or normal apartments or even schools than is shown in class 3 (>46).)

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[7] The injurious hard spots have been found to have Rockwell C hardness above 35 and are locally quenched regions of the pipe that were formed during hot rolling of the plate for the pipe.

[8] Design factor generally determines the portion of the specified minimum yield stress that is allowable as a design stress, i.e., a 0.72 design factor on an X52 grade steel allows a maximum hoop stress of 37,400 psi.

Based on individual house count surveys taken in 2004, the Rancho pipeline in the city limits of Austin jurisdictional limits consists of Class 1, 2 and 3 locations. The pipeline will be operated from a pressure viewpoint as though it were entirely in a Class 3 Location with the highest allowable pressure/stress based on the pipe on the west side of the city which is 24" x 0.312", X52 pipe. (It should noted that other requirements such as valve spacing will be based on the existing Class locations.) The maximum allowable pressure in the Class 3 location is limited to 676 psig. (The previous maximum allowable pressure for the line as a liquid line was 973 psig, which is 44 percent higher.)

$P_L$ = (2*S*t/d)*F= (2*52000*0.312/24)*0.72 = 973 psig in liquid service prior to conversion.

$P_G$ = (2*S*t/d)*F= (2*52000*0.312/24)*0.50 = 676 psig in natural gas service after conversion.

Where:

$P_L$ = Pressure in liquid service (psig)
$P_G$ = Pressure in natural gas service (psig)
t = Nominal wall thickness (inches)
S = Specified minimum Yield Strength (psi)
D = Nominal outside diameter
F = Design Factor (0.72 for liquid and 0.5 for Class 3 natural gas)

If one were to assume that the prior maximum operating pressure of 973 psig was a strength test, which lasted for 50 years, then the pipeline now operating at 676 psig is operating at 69.4% of the proven minimum strength, which was 72% of its theoretical strength. The Federal and State Codes allow for operating the pipeline at a maximum of 80% of the strength test pressure (up to a maximum test pressure of 90% SMYS) but in this case the Class 3 location will override and dictate a maximum allowable operating pressure of 50% of SMYS.

## Assessment of Pipeline Block Valves

Block valves are used on gas transmission pipelines to facilitate maintenance on a pipeline and to provide a means of shutting down a pipeline in the event of an incident.

In the region of the pipeline within the Austin ETJ, from station 13950+06 on the west to station 15328+16 on the east end, there are three mainline block valve locations proposed by Kinder-Morgan at the stations shown in Table 3 and in Figure 1. These locations have valve spacing of 4.9 to 12 miles. In determining these valve locations, Kinder-Morgan has used the existing Class locations of 1 through 3 and the 49 CFR Part 192 requirements. The valve locations shown in Table 3 have been checked for compliance with the Part 192 Class location valve spacing requirements as shown in the following and are in compliance.

> *"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 21/2 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 71/2 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.*

**Table 3. Kinder Morgan Proposed Locations of Block Valves**

| Valve No. | Location | Station No. (Mile Post) | Distance Between Valves, miles |
|---|---|---|---|
| MLV 11 | East Side of Highway 12 | 13707+05 | |
| | **West ETJ** | **13950+06** | 12.24 |
| MLV 10 | East Side of Northbound Loop 1 | 14353+42 (MP 111.96) | |
| | | | 7.15 |
| MLV 9 | West Side of Pleasant Valley Rd. | 14730+74 (MP 104.81) | |
| | | | 11.52 |
| | **East ETJ** | **15328+16** | |
| MLV 8 | Garfield Station | 15339+00 (MP 93.29) | |

Many times people tend to think that shutting a block valve on a natural gas pipeline will immediately shut off the supply of gas in the event of an incident as in closing a faucet on a water line. However, shutting a block valve on a line segment will not shut in a natural gas pipeline section fast enough to contain the effects of a gas release. As an example, a 12.25 mile long line segment of 24 inch diameter pipe was calculated to take more than 30 minutes to blow down to 25 percent of the maximum pressure[9]. A review[10] of incidents on natural gas pipelines indicated that in 71 incidents surveyed where 116 injuries and 28 fatalities occurred all but one injury occurred in less than 3 minutes. The one injury exception occurred in 49 minutes. Thus, block valves in the event of an incident help to reduce the consequences but do not immediately stop the flow of gas from a leak or rupture or lessen the impact of the initial release.

Although not required by Part 192, Kinder-Morgan is installing automatic closing Cameron ball block valves with Shafer RV actuators that are automatic closing, which will assist in rapid closure of the valves in the event of a major leak. The valves are set to close when the

[9] The 25% level is an arbitrary level to define the blowdown time. This was selected as a pressure level where the flame radiation would be significantly less than at full pressure and historically injuries and fatalities occur in the first few minutes of the incident.

[10] C.R. Sparkes, et al, Remote and Automatic Main Line Valve Technology Assessment, GRI-95/0101, July 1995, pp B1 -B4.

pressure drop in the pipeline exceeds 15 psi in a minute.  This will help to reduce the consequences from an incident.

A review was conducted to assess whether reducing the valve spacing to a uniform, 8 mile spacing would significantly reduce the impact of an incident.  The first case examined was the worst case where a rupture occurred at one end of a pipeline segment.  The results indicated that if a rupture occurred at one end of the longest pipeline valve segment (12.24 miles), the time for blowdown to 25 percent of the initial pressure is 25.5 minutes whereas for a similar condition on an 8 mile segment the time for blowdown to 25 percent of the initial pressure is 14.5 minutes, which is not a significant change.  Also, another scenario examined was blowdown from the middle point in a 12.24 mile segment and here the time for blowdown to 25 percent of the initial pressure was 9.8 minutes.  These data suggest that there is no significant benefit in reducing the valve spacing, as the times are already long enough that most of the consequences will have been sustained in the first few minutes.

## OVERVIEW OF INTEGRITY ASSESSMENT METHODS APPLIED TO KINDER-MORGAN RANCHO PIPELINE

One key consideration in evaluating inspection methods applied to a pipeline for integrity assessment is whether all of the possible types of defects of concern can be detected by the inspection/test methods used.  The defects of concern in a pipeline have been identified in ASME B31.8S 2001 Managing System Integrity of Gas pipelines.  Table 4 provides an overview of the integrity concerns and methodologies for addressing them.  The table indicates that Kinder-Morgan in the conversion of the Rancho pipeline is addressing all of the issues that can be addressed to check on the integrity of the pipeline as it enters service.

Kinder-Morgan plans a two-step program to assess the integrity of the existing pipeline.  The two steps are:  1) Conduct an ILI of the Rancho Pipeline using a deformation or caliper tool and a high resolution Magnetic Flux Leakage (HR MFL) tool and 2) performing a combination hydrostatic strength and leak test of the pipeline.

**Table 4. Integrity Concerns and Methodologies Applied to Rancho Pipeline**

| Anomaly Concerns | Means of Detection | Addressed by Kinder-Morgan |
|---|---|---|
| **Time Dependent** | | |
| 1. External Corrosion | Pressure testing, MFL ILI, UT ILI | Yes, Pressure testing and MFL ILI |
| 2. Internal Corrosion | Pressure testing, MFL ILI, UT ILI | Yes, Pressure testing and MFL ILI |
| 3. Stress Corrosion Cracking | Pressure testing, and UT crack detection ILI | Yes, Pressure testing |
| 4. Hydrogen Cracking in Hard Spots | MFL ILI | Yes, MFL ILI |
| **Stable** | | |
| 5. Manufacturing Related; defective pipe seam and defective pipe | Pressure testing and UT crack detection ILI | Yes, Pressure testing |
| 6. Welding/Fabrication /Construction Related; wrinkle bends, | A combination is required, caliper ILI, MFL ILI, and pressure testing | Yes, all three methods are being used |

| Anomaly Concerns | Means of Detection | Addressed by Kinder-Morgan |
|---|---|---|
| **Time Independent** | | |
| 7. Third Party/ Mechanical damage | Caliper ILI and pressure testing | Yes, both are being applied |
| 8. Incorrect Operations | Training of Operators and personnel working on the line | Yes |
| 9. Weather Related and Outside Force; lightening, rains, floods, earth movements. | Inspections and ILI are not effective. The most significant preventative measure is to monitor soil areas where sliding is possible and monitor weather conditions to be alerted to possible weather related situations | Yes |

## ILI ASSESSMENT

There are several different technologies available for in-line inspection (ILI) of operating pipelines. Two of the more common techniques were utilized to establish the structural integrity of the Rancho pipeline and they are Magnetic Flux Leakage (MFL) and Deformation.

The MFL technology has been used in this pipeline in three forms. MFL can best be described an inspection process wherein a magnetic field is induced into a steel pipeline and will remain in the steel unless there is a reduction in the wall thickness of the pipe. When there is an internal or external surface metal loss reducing the wall thickness, there will be a corresponding and proportional “leakage” of flux to both pipe surfaces. The MFL device detects and records the various physical characteristics of the flux leakage by location for analysis after the device is removed from the pipeline. The completely self-contained inspection device is propelled through a pipeline by the flow of fluid being transported and usually consists of three sections. The front section houses the power cells (batteries), the middle section induces the magnetic field into the pipe and contains an array of sensors capable of detecting flux leakage, and the rear section usually contains the recording and electronic devices. All three sections are joined by universal joints, which provide the flexibility required to traverse the pipelines.

Under previous pipeline ownership, “conventional” or low resolution MFL (LRMFL) was used and it provided a reasonably reliable insight into metal loss or corrosion issues that might have been present in the pipeline. There is evidence that this data was used to eliminate a few areas of concern relating to external corrosion in the Austin area but we did not have access to the specific data so we cannot comment on the quality of the data that was obtained or the effective utilization of that data by previous Rancho owners. Historic information of this type can serve to assist in evaluation of defect growth but due to the inaccuracy of some of the older technology tools as compared to that in use today, it is not practical to rely on those types of comparisons for finite system integrity evaluation. Comparison to previous data is sometimes used forensically to help understand when a particular issue began or to estimate rate of change with time. These factors can be very valuable when there is a third party that has contributed to the issue or for identifying a vendor that has provided a faulty product but it is seldom useful in the process of restoring system integrity. For current integrity evaluation, we will concentrate on current data, which will be discussed later.

A slight variation of the LRMFL is the hardspot (HSMFL) detection device. This tool operates on the same flux leakage principle but rather than the flux leakage occurring because of a reduction in wall thickness, it occurs due to the reduction in the magnetic permeability of the steel within the hardspot as compared to the surrounding steel.

The third type of MFL device application in this pipeline is the High Resolution MFL (HRMFL) device that was run in 2003 as a part of the preparation for conversion to natural gas. The HRMFL is a state-of-the-art device, which has the capability to induce a much stronger magnetic field into the pipe, has many, many more sensors around the circumference, and the data is recorded digitally at a very high sample rate. All of these factors provide for a much greater transverse and longitudinal resolution as well as an increased sensitivity to low level defects and greater overall data dependability. The device chosen for this inspection has a proven record and is considered to be the best available in the market.

The second technology utilized is a mechanical device used to evaluate the physical deformation of the pipe surface as caused by some outside force. That force might be in the form of a rock, skid, or other discontinuity in the bottom of the ditch causing a dent due to the weight of the pipe, the product in the pipe, and the soil overburden, or it might be in the form of impact caused by some type of excavating machine actually striking the pipe near the top. The distinction between metal loss and deformation is that there is no reduction in wall thickness in deformation, it is merely deformed. The deformation device employed in the 2003 evaluation, in preparation for conversion to natural gas, was one of the more modern devices available and is probably the one chosen most often throughout the world for these types of inspections.

All of the 2003 ILI data was evaluated from both the High Resolution Magnetic Flux (HRMFL) as provided by GE-PII and the Deformation survey data provided by Enduro and the data was found to be of high quality and therefore should identify the anomalies detectable with the tools employed (see Table 4) in the pipeline. The results of this evaluation can be seen graphically in Figure 2.

Part 192.933 and the referenced ASME B31.8S requires that: ”Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. This would include any corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME B31G or equivalent.” In this case the MAOP is 50% of SMYS and thus the failure level referred to will be 55% of SMYS.

Kinder-Morgan has removed all pipe containing metal loss defects that exceed 40% wall thickness penetration regardless of length. As shown in Figure 6, all of the defects removed are significantly below and to the left of the 55% of SMYS curve. Thus, this action, a requirement of the K-M Company operating procedures, exceeds those mitigation actions required by Federal and State codes and further, it exceeds common Industry Standards.

***Hard Spots***

One potential threat examined was the possibility that this pipeline might contain “Hardspots”. Hardspots in this early 50’s vintage A.O. Smith pipe is typically the product of accidental quenching with water or hydraulic oil during the pipe manufacturing process and has been known to be the cause of several pipeline failures in the past from a hydrogen stress cracking mechanism. Thus, this phenomenon was high on the list of issues to evaluate as it relates to this particular pipeline within the Austin ETJ. A “Hardspot” ILI survey was run on the entire Rancho system under prior ownership in the mid 1990's and the results ruled out the presence of this potentially hazardous condition within the Austin ETJ. One location was found at station number 6475+58, some 140 miles West of Austin that had a hardspot-like indication in the survey data, which had been previously excavated. The ILI data showed it to be a minimal indication, approximately 50 Bhn (Brinnell hardness) over the surrounding pipe, and when it was evaluated in the field after excavation; it was found to be approximately 200 Bhn with the surrounding pipe reading 100-150 Bhn. The maximum hardness allowed by API for this grade is 327 Bhn. The presence of, detection of, and proper analysis of this minimal hardspot allows us to conclude that there is a high probability that the Hardspot survey was performed properly and that there are no injurious hardspots within the Austin ETJ. We also know that there were several hardspots found East of Austin in the Houston area that were also removed from the pipeline by the prior owners.

### *Slot Corrosion*

Another threat that is typical in pipelines carrying some types of West Texas crude oil is the presence of internal slot corrosion, in the bottom, which can be especially dangerous due to its extensive longitudinal orientation in the presence of circumferential forces resulting from the hoop stress. These injurious anomalies are the result of the presence of $H_2S$ in the flowing product which, when mixed with even very small accumulations of water, is extremely corrosive. We reviewed the HRMFL data throughout the Austin ETJ and did not find any indication of the presence of this unique and easily recognizable signal character. We did find several locations where there were isolated internal pits but they were all very short in length and very shallow. Our opinion is that most of these, due to their random circumferential locations, will prove out to be totally non-injurious internal slivers (.001- 010" thick) on the pipe surface that have a ragged edge and generate a significant magnetic signal for their small size. It must be pointed out that internal slot corrosion is typically very smooth and does not have significant flux leakage for evaluation by ILI devices utilizing longitudinal magnetic flux such as the HRMFL tool, which was run in this pipeline. When this occurs and the leakage signal is very small or practically nonexistent, there will be, however, a clearly distinguishable signal resulting from "shoe chatter" as it traverses these locations containing longitudinal slot corrosion. So, in this case, one might have very low-level flux leakage and a minimal "chatter" signal that might be passed over by an analyst charged with the macro responsibility over many miles of pipeline. For this short distance across the Austin ETJ, it was practical for us to focus down to the smallest indications that might represent internal slot corrosion and none were found. Further, as described elsewhere, the hydrostatic testing process will be very effective in removing any injurious internal, longitudinal slot corrosion that may be missed with HRMFL.

### *External/Internal Corrosion*

Another threat that might exist in this pipeline through the Austin ETJ is external or internal corrosion. The HRMFL equipment utilized in this survey is very sensitive to these types of three dimensional metal loss defects and the analysis of the severity of such metal loss has been proven to be accurate over time. Metal loss depth and axial length are the critical parameters in determining the strength of pipe containing corrosion pitting as is described more fully elsewhere within this document. For the most part, the external corrosion found within the Austin ETJ is isolated, short, shallow, and substantially benign from a structural point of view. Kinder-Morgan removed all pipe that had corrosion with a depth of 40% of the wall thickness and greater, regardless of length[11]. Further, they removed several defects that were less than

[11] K-M O&M procedures require investigating all anomalies 40% and greater but in the Austin Area they cut-out these anomalies.

40% wall thickness penetration but were longer in length making them subject to hydrostatic test failure when tested to 110% of the yield strength (SMYS). As discussed in other locations within this review, the pipeline will be operated with a maximum allowable operating pressure of 50% of SMYS, which correlates to approximately 45% of the maximum test pressure. This low operating pressure level allows for easy management of and timely mitigation of the external corrosion issues without risk of failure.

Figure 2 shows that most of the corrosion from the Western boundary of the ETJ to Highway 183 East of I-35 is very isolated, shallow, and short along the longitudinal axis. It is obvious that these locations are not injurious in their present state and they appear to be under control from a cathodic protection point of view. Between Highway 183 and the Eastern ETJ boundary, there is a much higher density of external coating problems with apparent ineffective cathodic protection which has, over the course of many years, caused low level but widespread corrosion issues in this mostly farmland environment.

In addition to a commitment by Kinder-Morgan of timely re-running the pipeline with state-of-the art ILI devices as dictated by Federal and State Code, their own operating procedures, and the "standard of care" in the industry, they have committed to a total and complete evaluation of the existing cathodic protection and coating systems on this section of the pipeline in the very near future. A close interval survey (CIS) will be run by the end of 2004 and actions indicated by this thorough and very revealing process will be taken prior to the end of 2005. Kinder-Morgan has indicated that, based on what they have seen so far and without benefit of a CIS, additional anode beds <u>might</u> be required and <u>possibly</u> replacement of some coating material, especially in the mostly rural area near the Eastern extremity of the Austin ETJ. It is clear to the authors that it is Kinder-Morgan's intention to protect their investment in a prudent manner, and those actions will clearly provide for a safer pipeline.

### ***Mechanical Damage***

Another threat that could exist in this pipeline is mechanical damage from an outside force. This can come in the form of a deformation on the bottom caused by the pipeline resting on a rock, a skid, or some other obstruction in the bottom of the ditch, or it can be mechanical damage inflicted by heavy excavating equipment operated by a third party contractor. Knowing the rocky terrain in the Austin ETJ and the obvious residential, commercial, and infrastructure growth in the area since the mid 50's, mechanical damage can be a significant element in the system integrity evaluation. Additionally, longitudinal cracks can initiate and grow in "impact" type mechanical damage issues due to the cyclic pressures typically found in a liquid pipeline. These types of issues usually fail rather than leak. The deformation ILI survey described several deformation anomalies but they were all very shallow (<3%), smooth in character, and all at 6:00 on the bottom of the pipe. There were no deformation anomalies found anywhere on the circumference that were "abrupt" in physical character or that were believed to be impact induced

### ***Longitudinal Flash Weld Anomalies***

The final issue, which must be evaluated in this pipeline, is the "flash welded" longitudinal seam, a product of the pipe manufacturing process by A.O. Smith. There are no ILI devices available that have been proven to reliably evaluate the integrity of this weldment[12]. Thus, the only

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[12] HR TFI tools have been used to inspect the seams of ERW pipes with some success. However, to the best of the authors' knowledge they have not been used to inspect flash welds, which have a small weld

practical method to evaluate its integrity is by hydrostatic testing as will be discussed in this assessment.

### Population Density review:

In order to properly asses the potential risks that are present due to the presence of a pipeline traversing across a city with such a mixture of habitation and right-of-way access, it is mandatory that an up-to date and reasonably accurate evaluation of the population be made. Kinder-Morgan has made this assessment and their data is chronicled on aerial photography dated 8/22/03. Even though they did this work quite thoroughly and in keeping with State and Federal code requirements, it was important enough to duplicate many of their efforts in this

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reinforcement. Also, ultrasonic crack detection tools may be able to inspect flash weld seams but no one has attempted this.

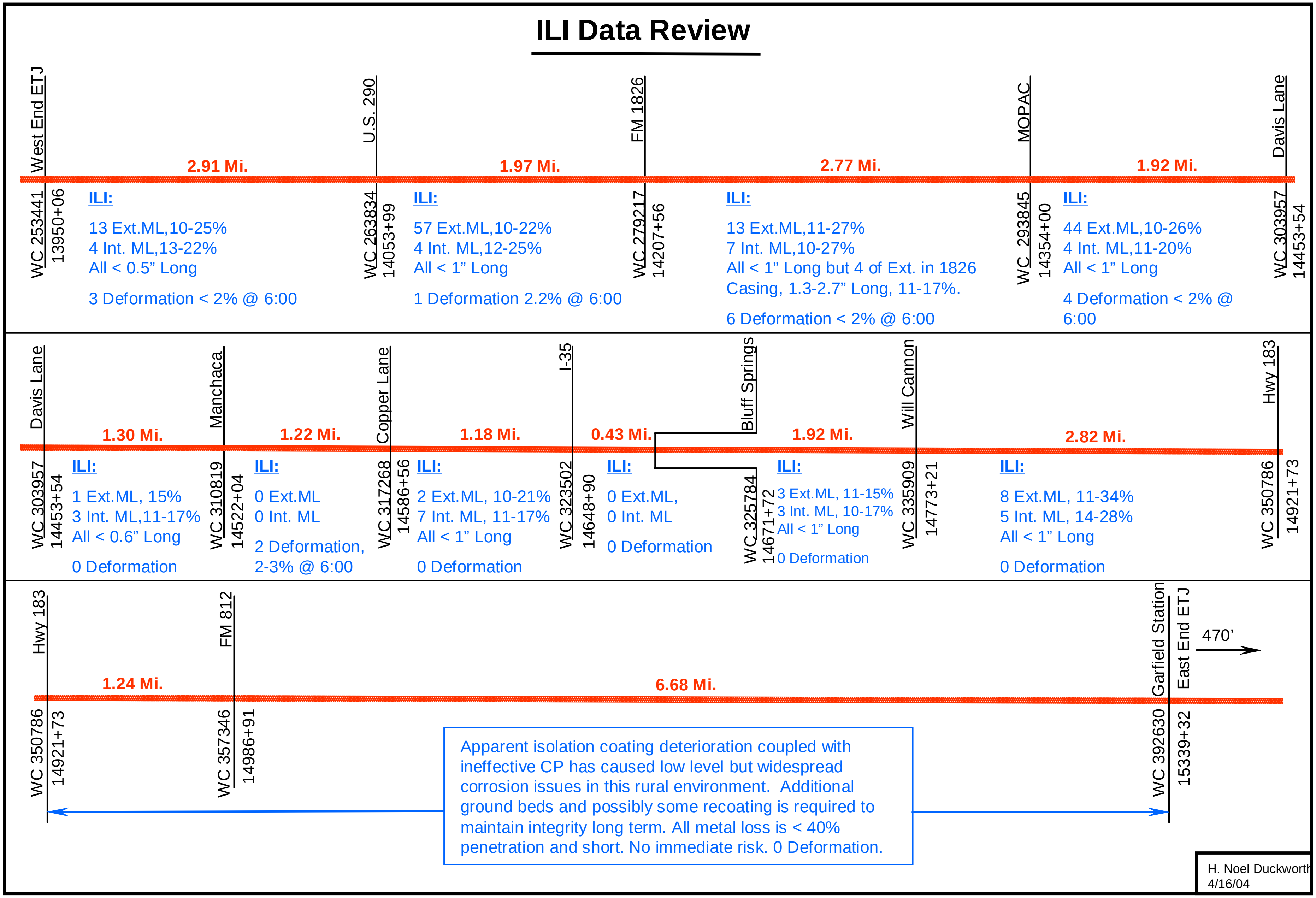


**Figure 2. ILI Data Review.**

Population Density / ILI Data Review

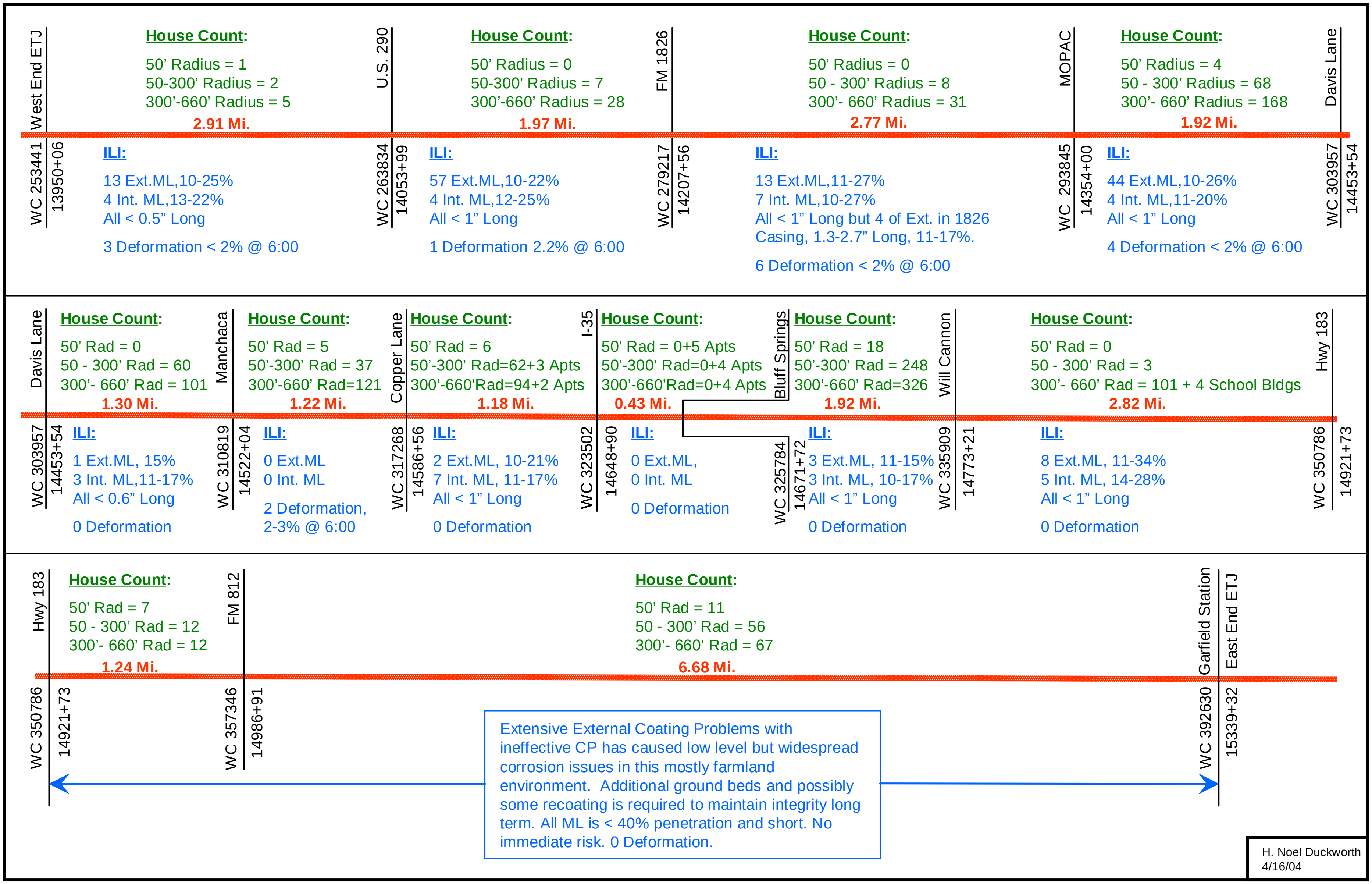


**Figure 3. Population Density and ILI Data Review.**

review. The result of our evaluation reasonably corresponds with that of Kinder-Morgan and is shown graphically in Figure 3 along with the data from Figure 2 for correlation purposes.

## ILI Inspection Results

One of the issues in an ILI inspection is: "How accurately do the tools predict the metal loss lengths and depths that are necessary to calculate failure pressures/severity of anomalies detected"? This issue was examined by comparing the predicted versus measured lengths and depths of anomalies detected with the HRMFL tool in Figures 4 and 5. The depth predictions are generally within the + or - 10% claimed accuracy of the HRMFL tool by the Vendors. The length predictions are not as good since 60% of them in this instance were in the non-conservative region where the measured lengths are longer than the predicted lengths. The problem with the length prediction inaccuracy is that it limits the ability to calculate failure pressures accurately. This makes it difficult to determine which anomalies need to be dug and field inspected. Adjacent pitting can interact structurally with each other such that they behave as one larger pit. There are several concepts relating to evaluating this "interaction" and Kinder-Morgan has chosen a conservative method that was developed as an element of the "RSTRENG" method of determining the strength of corroded pipe. In fact, Kinder-Morgan uses the RSTRENG model for all of their strength evaluations. In order for "RSTRENG" to be an accurate method of predicting pipe strength, the dimensions need to be precisely measured by hand and utilization of ILI data does not provide the finite detail required. It can be used, however, as a method to <u>estimate</u> strength and can be very effective in establishing priorities when there are many locations of corrosion. The errors described by the ILI data for defect length is caused by the application of the interaction rules and, while it is a greater error than normally found, it is offset by choosing such a low level depth removal criteria (40%).

Kinder-Morgan has elected to remove all anomalies that are 40% or more of the wall thickness in depth regardless of the length. This is a fairly reasonable approach for this line operating at 50% SMYS. What was found is that anomalies that were less than 2 inches in length have such high failure pressures that the length inaccuracy is not a problem. However, there were 4 anomalies that had measured lengths greater than 2 inches and the worst of these, from a failure prediction viewpoint, had a predicted failure pressure that decreased from 92 to 77% SMYS based on the measured depth and length, a reduction of 25%. The other reductions for anomalies greater than 2 inches ranged from 8 to 16%. Since this line was to be pressure tested from 100 to 110% SMYS it is important to make sure that all of the injurious anomalies that were detected with MFL were removed to reduce the probability of test failures. It was possible that the length inaccuracy would affect the effective removal of anomalies that could fail in the pressure test. Since there were no corrosion related failures during the high level pressure testing, this length prediction deficiency has been proven to not be an issue.

Kinder Morgan has indicated that they will perform an in-depth evaluation of their complete cathodic protection system and take appropriate action to assure that the external corrosion issues are mitigated. If this action is not implemented effectively or in a timely manner, then there could be a future issue relating to corrosion growth rate as compared to inspection frequency if the length inaccuracy continues to exist. Quite possibly, the 40% depth threshold might have to be adjusted depending on how fast the anomalies are increasing in depth or joining together to form longer effective anomalies. Another consideration would be to increase ILI inspection frequency to assure integrity.

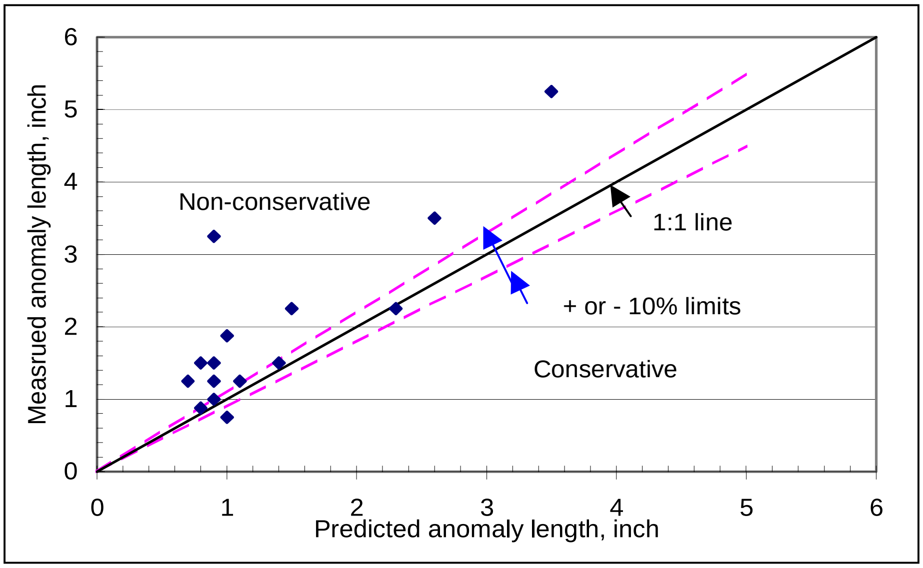


**Figure 4. Predicted versus Measured MFL Anomaly Lengths**

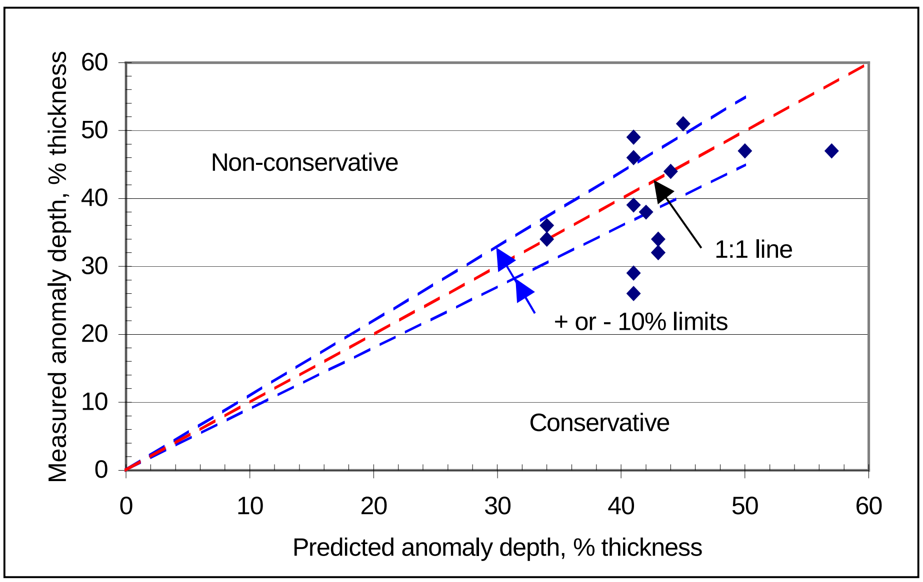


**Figure 5. Predicted versus Measured MFL Anomaly Depths**

Figure 6 presents the lengths and depths of the anomalies removed from the Rancho Pipeline. These are compared to calculated curves of failure stress levels for various length rectangular flaws in the Rancho pipe. All but two of the data points have calculated failure pressures above 100% SMYS. The two data points below 100% SMYS have calculated failure pressures of 77 and 93 % SMYS. These two would have failed in the planned hydrotest. The three data points between 100 and 110% SMYS may also have failed in the hydrotest depending on the elevation of the pipe at their locations. The remaining 10 data points have failure pressures that are too high to reach in a hydrotest illustrating the benefit of using ILI in place of hydrotesting for metal loss anomaly removal. Thus, while there is a length accuracy issue with the HRMFL data, the HRMFL is still capable of detecting anomalies that are much smaller than could be detected with a pressure test.

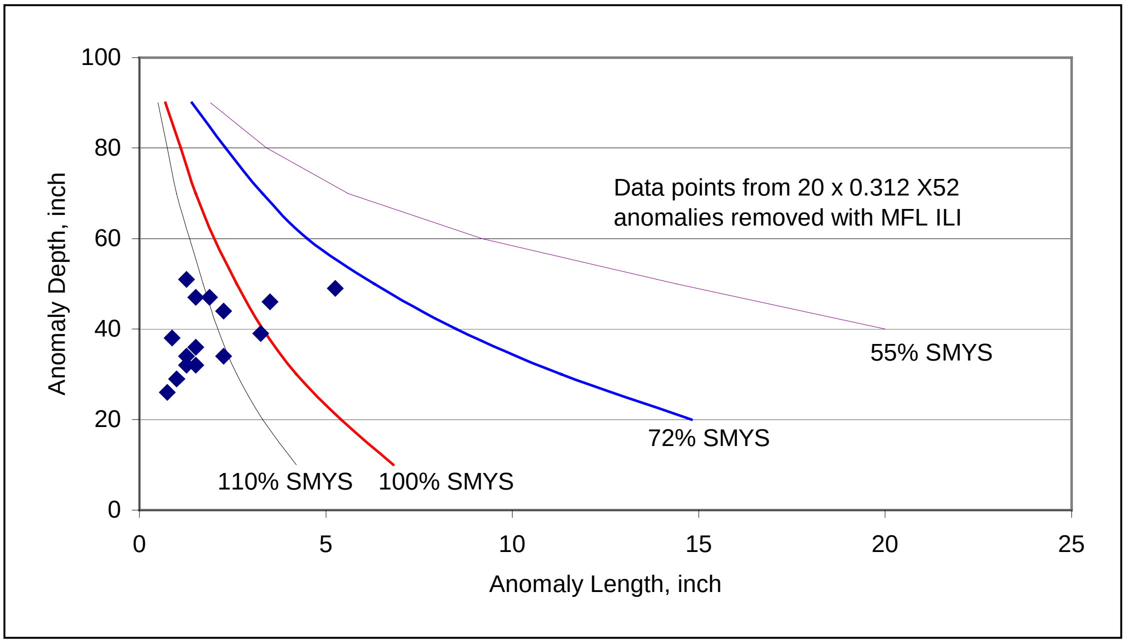


**Figure 6. Calculated Failure Pressures of Anomalies Removed From 24” x 0.312” X52 Rancho Pipe**

Even though the pipe has been inspected with a deformation tool and an MFL tool, those tools cannot inspect for some types of mechanical damage, flaws in the seam weld and other longitudinally oriented defects such as stress corrosion cracks (SCC). As indicated previously, there is no proven ILI tool that can detect and size anomalies in the flash weld seam and thus, to complete the integrity assessment, a pressure test was necessary.

# HYDROSTATIC TEST ASSESSMENT

## Proposed Kinder Morgan Pressure Test Plan

The Kinder Morgan hydrostatic test plan proposed for the Austin ETJ was to test the pipeline in three sections[13]. The proposed maximum and minimum pressures in the 0.312 inch wall thickness pipe were 1217 to 1351 psig corresponding to 90% SMYS (specified minimum yield strength) to 100% SMYS. The proposed maximum and minimum pressures in the 0.344 inch wall thickness pipe were 1217 to 1373 psig corresponding to 82% SMYS to 92% SMYS. The range in pressure is necessary because of the changes in elevation of the ground. The lower the elevation, the higher the test pressure and therefore the 100% SMYS stress level (0.312 inch wall pipe) will occur at the lowest elevation point in a test section and the 90% SMYS stress level will occur at the highest elevation point. This plan is referred to as Option 1. It is assumed that a sufficient pressure will be maintained at the test pressure for at least 8 hours to check for leaks.

Option 1 is in excess of the Part 192 rules established by OPS for natural gas transmission pipelines in Class 3 Locations. The Part 192 rules require the pipeline segment in a Class 3

13 A total of 5 test sections will be necessary to test the complete line but only 3 of these are within the jurisdiction of this review.

Location constructed before Nov. 1970 to be tested to 1.4 times the maximum allowable operating pressure, which in this case would be a minimum test pressure and minimum hold pressure of 946 psig (70% SMYS) and held for 8 hours for a leak check.

## Review of Kinder Morgan Test Plan

The purpose of the pressure test is to insure that there are no anomalies (such as in the weld seam, mechanical damage, or SCC anomalies) in the pipe as it enters service that could subsequently cause an incident on the pipeline. Or stated another way, that the pipe has a high integrity at the time it enters service. The higher the test pressure or stress level, the smaller the flaw that can remain in the pipe and the longer the time period for surviving flaws[14] to grow before they reach a critical size and retesting or reinspection is necessary.

The Kinder-Morgan test plan was reviewed to assess the stress level in the pipe during the proposed test at locations where houses are in close proximity to the pipeline. These results are shown in Table 5. The results shown under the Option 1 column indicate that in the 0.312 inch wall thickness pipe the stress levels in close proximity to clusters of houses expressed as % SMYS range from 93 to 95% SMYS. Similarly in the 0.344 inch wall thickness pipe, the stress levels range from 84 to 89% SMYS.

To assess the significance of the test stress level a calculated curve of flaw depths and lengths is presented in Figure 7. Figure 7 shows a calculated[15] plot of flaw sizes that are on the verge of failure at the stress levels shown for the 24 by 0.312 inch wall thickness X52 pipe with a pipe toughness (Charpy V-notch impact plateau energy) of 20 ft-lbs based on a 2/3 width specimen. (A similar plot exists for the 24 x 0.344 inch wall thickness X52 pipe except that the flaws are slightly larger at the same stress level.) A series of curves are shown along with a heavier curve that crosses the other curves. The series of curves are labeled with d/t values from 0.1 to 0.9, which indicates the depth, d of the flaw to the thickness, t of the pipe. Horizontally, the effect of total flaw length is shown, indicating that the longer a flaw, the lower the failure stress. Similarly the deeper a flaw, the lower the failure stress. The flaws represented by the curve are flaws of uniform depth or rectangular flaws. (This provides a conservative estimate of the failure stress as most flaws are parabolic and will have a higher failure stress.)

The heavy line curve that crosses many of the other curves separates leaks and breaks. When a flaw fails in the region above the heavy curve, it will fail as a rupture and below it the failure will be a leak.

Figure 7 indicates that at a 90% SMYS minimum stress level proposed for the pressure test, flaws that range from 1.2 inches long by 90% deep to 16.7 inches long by 10% deep would be on the verge of failure in the test. In the 24 x 0.344 inch X52 pipe, the stress levels are even lower, i.e., the minimum is 81.6% SMYS and the maximum is 92.6% SMYS in Kinder-Morgan's proposed hydrostatic pressure test plan. At a stress of 81.6% SMYS the surviving flaw sizes in

[14] Manual for Determining the Remaining Strength of Corroded Pipelines, ASME B31G-1991. Available from the American Society of Mechanical Engineers, 345 East 47th St. New York, NY 10017. .

[15] The flaws were calculated with a spreadsheet developed for the Pipeline Research Committee International and which formed the basis for the RSTRENG prediction of allowable stresses for corrosion flaws and anomalies and is now in the Part 192 of the OPS gas regulations. The equations and spreadsheet are available in Fracture Control Technology for Natural Gas Pipelines, by R.J.Eiber, T.A.Bubenik, and W.A. Maxey, NG-18 Report 208, December 1993, available from Technical Toolboxes web site (www.technicaltoolboxes.com)

the 24 x 0.344 inch X52 pipe are 1.5 inches long by 90% deep up to 22 inches long by 10 % deep. These are fairly large flaws, which is fortunate in that they demonstrate that pipelines can tolerate large flaws without failure. However, by testing to a higher-pressure level the remaining flaws would be smaller.

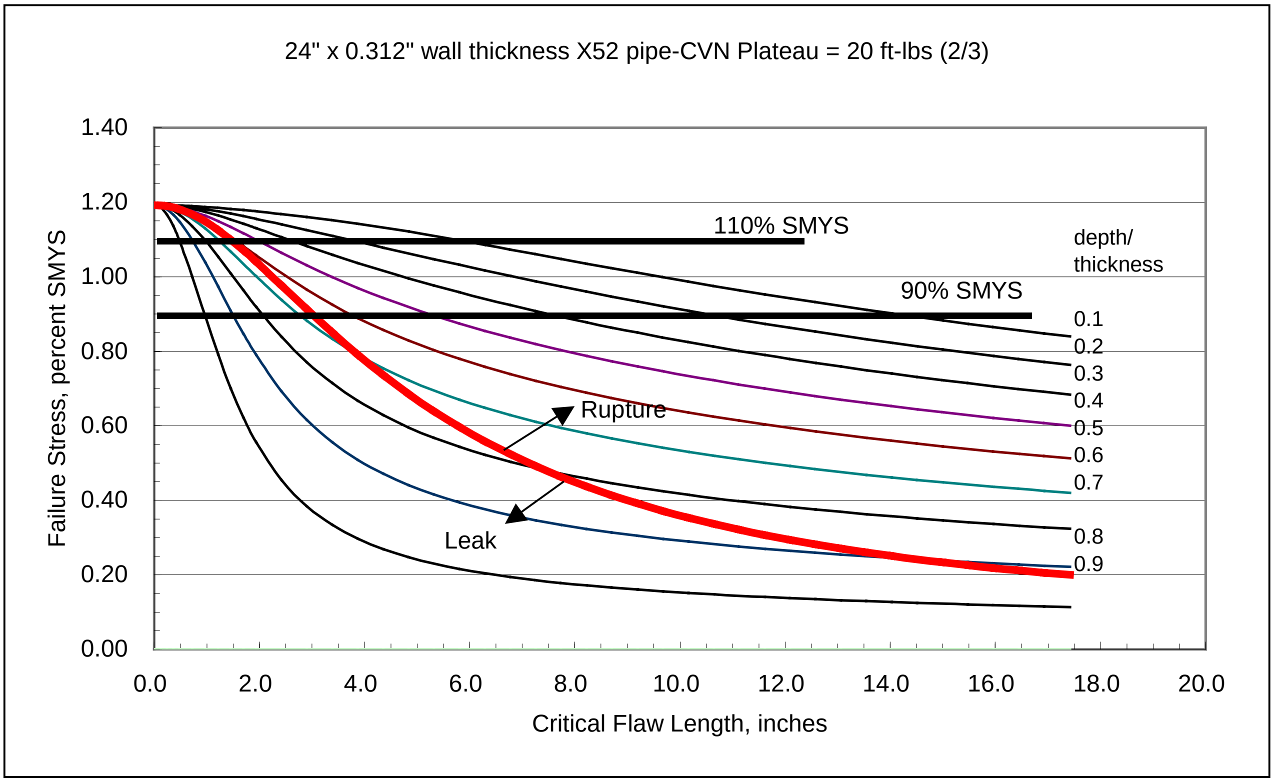


**Figure 7. Critical Flaw Depths and Lengths in 24 x 0.312 inch X52 Pipe**

Table 5 shows that the pressure test proposed by Kinder-Morgan tests the pipe to stress levels that are 84 to 95 percent SMYS in areas with homes within 50' and it is the experience of the authors that this stress level should be higher to more adequately demonstrate the integrity of the pipe and assure the public of its integrity.

***Initial Suggested Changes***

Three changes that improve the proposed pressure test are to separate the test sections at the location of the wall thickness change from 0.312 inches to 0.344 inches. Then the 0.312 inch wall thickness and 0.344 inch wall thickness sections can be each be tested to high pressure levels, typically 90 to 100% SMYS or higher. Option 1 only tests the 0.344 inch wall thickness pipe to 81.6% SMYS. This is illustrated in Figure 4, which is a revision of the Option 1 test plan.

Secondly, if the Eastern most test section end was moved to (at or near) the Eastern ETJ near the old Garfield pump station, then this would shorten the test section and be able to eliminate some hydraulic gradient. East of Garfield, which lowers the test pressure. This is especially important due to the presence of widespread, low-level, external corrosion between Hwy 183 and the Garfield Station. Additionally, the most recent aerial photography suggests that there is a school in this area and conservatism is always in order in these types of situations.

**Table 5. Review of Proposed Kinder Morgan Pressure Test**

| Test Sect. No | Station No. | Nearby Street | Part 192 Class Location | Number houses within 50 ft | Pressure Test Elevation, ft | Calc. Test Pressure, psig based on Option 1. | OPTION 1 81-100% SMYS Percent SMYS | | OPTION 2, 100-110% SMYS Percent SMYS for 0.312 inch wall pipe | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 0.312" WT | 0.344" WT | 0.312" WT | 0.344" WT |
| **2** | **13704+56** | | | | | | | | | |
| | 13950+00 | Wagon | 2 | 2 | 1000 | 1280 | 94.7 | | 105.2 | |
| | 14053+00 | Hwy 290 | 2 | 2 | 1094 | 1260 | 93.2 | | 103.6 | |
| **3** | **14207+17** | | | | | | | | | |
| | 14365+00 | Bremner | 3 | 14 | 810 | 1269 | 93.9 | | 104.3 | |
| | 14460+00 | Zeke-Alabama | 3 | 5 | 810 | 1269 | 93.9 | | 104.3 | |
| | **~14580+00** | **wall thickness change** | | | | | | | | |
| | 14609+00 | Wynne | 3 | 5 | 712 | 1312 | | 87.3 | | 97.9 |
| | 14629+00 | Ferndale | 3 | 11 | 640 | 1343 | | 89.4 | | 99.3 |
| **4** | **14626+01** | | | | | 1265 | | | | |
| | **14647+00** | **I 35** | | | | 1273 | | 84.2 | | 93.6 |
| | 14649+00 to 14651+00 | Quicksilver-Dixie | 3 | 25 | 580 | 1280 | | 84.7 | | 94.1 |
| | 14921+00 | Hwy 193 | 2 | 7 | 560 | 1292 | | 85.2 | | 94.7 |
| | 15022+00 | Bain | 2 | 3 | 544 | 1295 | | 86.0 | | 95.5 |
| | 15050+00 | Towery | 2 | 3 | 517 | 1276 | | 86.2 | | 95.8 |
| | 15154+00 | Kellum | 2 | 1 | 511 | | | 84.9 | | 94.3 |
| | 15241+00 to15337+00 | Stony Mont | 3 | 15 | 554 | | | | | |
| | | **Total** | | 93 | | | | | | |

Third, the authors believe that the test pressure should be increased to 110% SMYS if it is possible. Accomplishing this will assure the public that the pipe has been demonstrated to have a high integrity when placed in service. This pipeline has had excellent service with very few service incidents (mainly corrosion and mechanical damage) and these will probably be the continuing integrity concerns as has been discussed previously. One of the benefits of testing the pipeline to a high stress level at this time is that it will allow the line to remain in operation for a longer period after the test without reinspection since the starting anomalies will be smaller allowing more time for their growth until they reach a critical size and thus extending the time between inspections.

***Revised Suggested Changes***

Kinder-Morgan reviewed the suggested changes listed above and were concerned about how uniform the wall thickness was in Test Section 4 and how significant moving the test header would be on the stress levels that could be achieved. Kinder-Morgan checked the wall thickness in several locations of Test Section 4 by digging to the top of the pipe and measuring the wall thickness ultrasonically. The data generated revealed that there was 0.312 inch wall thickness pipe mixed in with the 0.344 inch wall thickness pipe and therefore it was potentially damaging to treat the 0.344 inch pipe as heavier wall in a pressure test. The potential damage would be that the 0.312 inch pipe could be expanded in the test which would likely separate the corrosion coating from the pipe making future corrosion control very difficult. To prevent this from occurring, all of the pipe will be treated as 0.312 inch wall thickness pipe.

The second request to move the test header west to shorten the test section and reduce the hydraulic gradient revealed that if the wall thickness was to be treated as 0.312 inch throughout the section that moving the test header would allow the stress in the pipe to be increased from 98.5% SMYS to 105.8% SMYS at the high elevation point. However, since the minimum stress (98.5% SMYS) was already within 1.5% SMYS of the minimum in the other two test sections, we agreed to the slightly lower minimum stress in Test Section 4 in trade for the higher stress levels in the other test sections (100 to 110% SMYS). Therefore the first two changes have been eliminated and the third change was implemented.

In proposing a high-pressure test, the authors were concerned about the following two conditions:

**Condition One:** The pipe should not be pressured to such a high pressure that the pipe is deformed or enlarged in the test. This could damage the corrosion protection coating, which in the long run would be detrimental. The authors believe that a pressure versus volume plot should be developed during the test to provide control over yielding. When the slope of the pressure-volume curve changes from the initial slope to one-half of that slope, pipe deformation is eminent and the test pressure should not be increased further. Alternatively, the first pump "double stroke" (without corresponding pressure increase) could be used to define this yield point.

**Condition Two:** Flash weld pipe and low frequency ERW pipe have a tendency to contain small flaws in the weld seam. Therefore, it is recommended that if a failure or leak occurs due to a seam anomaly at a pressure equivalent to 90% SMYS at the high elevation point that the test should be stopped to avoid a series of failures that will not improve the integrity of the pipeline but which could result in a series of test failures. It is not likely that by continuing to test and experiencing failures that all the seam anomalies could be removed, as the trend is that as the anomalies get smaller in size that they also increase in frequency. The experience that has been gained in testing flash weld and low frequency ERW pipe is that when failures appear in pressure testing it is better to stop the test and not risk more failures. This conclusion has been reached because the small flaws in the weld seams will grow as a result of the cycles of pressure applied as a number of test failures are encountered and repaired. Experience indicates that the amount of pressure increase that can be achieved when a number of test failures occur is relatively small and therefore does not significantly reduce the size of any remaining flaws. Experience has also indicated that in this situation "pressure reversals" are possible during testing. Pressure reversals refer to a phenomenon in which a pipe fails at a pressure lower than it has been recently tested to because defects in the pipe have grown. Pressure reversals can and should be avoided.

## Recommended Pressure Test

Therefore, it is recommended that a pressure test be conducted by increasing the pressure in each test section in three steps. The goal of the three steps is to provide time for the pressure to stabilize at each pressure level and time for failures to occur.

- The first step is to pressure each test section to 90 to 100% SMYS and hold it for 10 minutes.
- If no failures or leaks occur, the second step is increase the pressure to 95 to 105% SMYS and hold it for 10 minutes.
- Again, if no failures or leaks occur, the third step is to increase the pressure to 100 to 110% SMYS and hold it for 10 minutes.
- If no failures or leaks occur, decrease the pressure to 70% SMYS at the high elevation point and hold for the required leak check period. This relatively low pressure is the minimum federal required pressure for the leak check and will assure that no anomalies grow during the leak check.

If a failure or leak occurs that is due to a weld seam defect and the maximum pressure in the test section at the high elevation point has not reached 90% SMYS, repair the failure or leak and repressurize the test section to achieve 90% SMYS at the high elevation point with a leak check to follow at 70% SMYS stress level in accordance with Part 192. (Kinder-Morgan actually leak tested at a minimum pressure of 90% SMYS even though the code only required 70% SMYS.) If a failure occurs at a pressure in the test section above 90 percent SMYS (at the high elevation point) then, the failure should be repaired and the test section repressurized to 75 -80 percent SMYS at the high elevation point and held at that pressure for the leak check.

Appendix E contains the final Kinder-Morgan hydrostatic test plan, which is in agreement with the suggestions identified herein.

## Review of Results of Hydrostatic Test of Rancho Pipeline

The three test sections within the Austin ETJ are Sections 2, 3, and 4 as shown in Appendix E. Each section was to be pressure tested with a high pressure (minimum stress level) of 100% SMYS (stress range from 100 to 110% SMYS) followed by a leak test between 90 and 100% SMYS which was held for 8 hours while the pressure was monitored for leaks. Within the Austin ETJ, Section 2 was tested to a stress level from 101.4 to 108.9% SMYS (the range is due to elevation differences and the weight of the water) (in the complete Section 2 the stresses ranged from 100.0 to 108.9% SMYS). Section 3 was tested to a stress level from 100.0 to 109.9% SMYS. Section 4 was tested to a stress level from 94.3 to 101.0% SMYS at which point a failure occurred. (In the complete section, the stresses ranged from 94.3 to 105.9% SMYS.) The failure was repaired and the section leak tested. The leak test of Sections 2, 3 and 4 were all in the range of 90 to 100% SMYS with no leaks detected. The remaining test sections outside of the Austin ETJ were pressure tested to stress levels of 90 to 100% SMYS without incident.

The only failure that occurred in testing the complete 130 mile pipeline occurred in Test Section 4. The failure occurred at a stress of 103.2% SMYS at a location approximately 12.3 miles east of the Austin East ETJ. The failure was due to an anomaly in the weld seam, which is one of the main reasons why the test was conducted. It is much better to have a failure on test with water in the pipeline than in service with natural gas. In keeping with the testing protocol, the strength test of Section 4 was acceptable since it was above 90% of SMYS at the high point in the line segment.

These results are very significant as they indicate that the integrity of this pipe is very good. The pressure test assessed the integrity of the longitudinal weld seam (as well as the rest of the pipe) however the body of the pipe had been inspected using the deformation and HRMFL tools. The test thus also validated the ILI inspection results. This completed the integrity assessment of the pipeline. The fact that only one failure occurred in testing the complete line to a pressure that is up to 160 percent of the original 1953 hydrotest pressure provides assurance of the integrity of the longitudinal pipe seam and the pipe body indicating that this pipeline has been well maintained during it past 50 years of service.

## ASSESSMENT OF INCIDENT CONSEQUENCES

It was observed visually and from aerial photographs of the pipeline that there are a number of houses in close proximity to the pipeline. As a consequence of that, the impact of an incident was assessed on the houses and also the adjacent pipelines that are also in close proximity at a number of locations.

### Proximity of Occupied Buildings

The building proximity was reviewed by visually observing the distance from the pipeline to occupied buildings in driving along the pipeline route and by reviewing aerial photographs of the pipeline and the adjacent buildings. Figures 8 and 9 present views of the pipeline showing its proximity to houses. In Figure 8, the house is about 70 feet from the pipeline as indicated by the white sign. In Figure 9, the pipeline right of way is in a utility corridor that is about 100 feet from houses and apartments. There are other areas along the line where the pipeline is remote from houses and apartments and is in a Class 1 location. While the housing location is diverse our focus was on the buildings in close proximity to the pipeline.

**Figure 8. Rancho Pipeline Proximity to Backyards and Houses**

**Figure 9. Rancho Pipeline Location Relative to Houses**

## Impact of a Line Rupture

One question regarding this line is: What is the effect of a rupture or leak on nearby houses? To assess this, an assumption was made that rupture of the pipeline occurs and the gas jetting from both ends of the pipe ignites.  The authors experience with ignition of natural gas pipeline ruptures is that approximately 50% of them ignite.  This is based on a number of pipe rupture experiments and incidents examined by the authors.

To assess the impact of a rupture an impact distance has been defined using a reference level of heat flux of 5000 BTU/hr $ft^2$ . This reference heat flux[16] is based on:

- the heat flux will not cause spontaneous ignition of wood in the absence of an ignition source in 20 minutes, and
- a person outdoors can reasonably be expected to find a sheltered location within 200 feet of their initial position, assuming they a running at 5 MPH within a 30 second exposure time and this is associated with a 1% lethality.

This issue was addressed in an American Society of Mechanical Engineers document on Managing System Integrity of Gas Pipelines and resulted in an impact radius equation[17], which is presented as Equation 1.

$$\mathbf{r = 0.69(d\sqrt{p})} \qquad 1$$

Where: 0.69 is the factor for natural gas.
d is the pipe diameter in inches.
p is the pipe operating pressure, in psig.

For the Rancho pipeline, r is 431 feet for the 24 inch diameter pipe at an operating pressure of 676 psig (50% SMYS in the 0.312 inch wall thickness pipe). This means that structures within 431 feet of the pipeline centerline could be subject to radiation that could start fires.

The aerial photographs indicate that there are a number of houses in close proximity to the Rancho Pipeline. As an example, the review found that there are approximately 93 houses within 50 feet of the pipeline, see Table 5. Also, there are over 1000 houses and apartments within a distance of 431 feet of the pipeline centerline. These results indicate that this line segment must be of the highest possible integrity when it is placed into service and the maintenance and inspections of the line planned in the Integrity Management Plan (IMP) must maintain that level of integrity.

***Impact of a Leak***

One impact of a leak has been assessed by examining the impact radius of a 1 inch and a 2 inch diameter hole in the pipeline. The hole sizes were based on the possibility that a back hoe tooth could create holes that are 1 to 2 inches in diameter.

Equation 1, presented in the previous section, has been used to assess the distance where 5000 BTU/hr $ft^2$ exists but the pipe diameter has been changed to 1 to 2 inches. This will provide a conservative estimate of the effect of a single hole leak as it assumes that there is a complete severance of the pipe with two ends of the pipe jetting gas that are on fire. Equation 1 with p=676 psig and d=1 inches results in an impact radius of 18 feet and a 2 inch diameter hole results in an impact radius of 36 feet. This reemphasizes the need to avoid incidents in service through adequate in-line inspection, corrosion control, right-of-way maintenance and inspection.

A second aspect of a leak is whether the gas might migrate through the soil to a structure. The most likely possibility of this occurring is if there is a utility that passes over the pipeline and

[16] A model for Sizing High Consequence Areas Associated with Natural Gas Pipelines, Mark Stephens, C-FER Technologies, GRI Report, GRI-00/0189, October, 2000.
[17] ASME B31.8S 2001 Supplement to B31.8 on Managing System Integrity of Gas Pipelines, 2002, ASME International, 3 Park Ave. N.Y., N.Y, 10016

then enters a nearby structure. The most common occurrence is with a service line into a residence from a natural gas distribution main. David Johns suggested that it might be possible for gas to migrate along a void moving horizontally and possibly penetrating under the slab of a house allowing the gas to penetrate the house.[18] However, the likelihood of this occuring requires a number of unlikely events to occur starting with the fact that the pipe is in a trench with a disturbed soil above it and therefore any voids would be disturbed by the trench and therefore has been judged to be too remote for consideration. As far as could be discerned from the information available, no situations such as these were found along the pipeline.

Another issue is that the soil is limestone that can be quite solid and possibly provide a shield to a small leak. Large leaks will tend to blow off the overburden due to the 676 psig pressure in the line. The concern was whether there were any locations in the soil where gas could collect from a very small leak such as in the seam weld. Natural gas in the atmosphere will ignite and burn but natural gas mixed with air in a confined space will explode/detonate if an ignition source is available. In discussing this with David Johns, City of Austin Geologist, it was learned that there are a number of small caverns in the limestone that might under rather unusual circumstances lead to a collection of natural gas.[19] Certainly an unusual circumstance would be required for this “lighter than air” natural gas escaping from the pipeline at a small leak to migrate downward into a cavern. Even if this does occur there is no source of ignition that can be envisioned that would cause detonation of the gas and therefore this has been dismissed as a possible consequence of a small leak.

### *Pipe Defect Tolerance*

The Charpy plateau energy can be used to assess the relative toughness of the pipe in the Rancho pipeline. Table 1 shows that the pipe body has a Charpy V notch (CVN) impact energy ranging from 20.2 to 25 ft-lbs. These values by themselves do not indicate anything but pipeline industry research indicates that as pipe diameters increase, the Charpy energy needs to increase to assure a reasonable flaw tolerance. Also, as the toughness increases the flaw tolerance reaches a plateau above which further increases are not beneficial. For the 24 x 0.312 X52 pipe under consideration, Figure 10 presents a curve of through-wall[20] flaw tolerance for a hoop stress level of 50% SMYS versus Charpy plateau energy. At a full-size Charpy energy of 30 ft-lbs (2/3 Charpy energy of 20 ft-lbs), the critical through wall flaw length is 7.2 inches and is 94% of the theoretical maximum flaw length of 7.65 inches for infinitely tough pipe of this diameter, wall thickness and grade. The conclusion is that the fracture toughness or flaw tolerance of the body of this pipe is very good. This means that from the viewpoint of corrosion tolerance this pipe is as good as pipes currently being produced. This is also reflected in the good prior service of this pipe in liquid service.

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[18] As these voids can be located even with or above the pipeline elevation, gas could easily migrate into them to collect or migrate off the ROW. In addition, there are residential or commerical properties located topographically higher than the pipeline, so gas moving along a karst conduit could migrate uphill to an ignition source.

[19] From David Johns: Voids are commonly found in walls of shallow utility line trenches at depths of less than 4 ft. Many were documented in the nearby Longhorn Pipeline trench during its replacement. The voids can vary from small chambers less than 1 ft3 to bedding planes openings of greater than 10ft3 and their laterial extent can be large.

[20] A through-wall flaw is a leaking flaw that is all the way through the pipe thickness. It represents the dividing flaw size between a leak and a rupture.

Figure 7 presented the flaw lengths and depths of part-through flaws that can be tolerated in 24 x 0.312 inch wall thickness X52 pipe. (Note: the 0.344 inch wall thickness pipe with a similar toughness will tolerate slightly larger flaws.) As an example of the usage of the figure, at a failure stress of 50%SMYS (operating stress level), this pipe can tolerate a rectangular shaped flaw that is 90% of the wall thickness in depth and 1.75 inches in length. Similarly at the same stress level, a flaw that is 10% through the wall can be tolerated that is 15.5 inches long. At this stress level the length of flaw that will lead to rupture is 7.2 inches as indicated by the TWC (through wall curve); shorter flaws will lead to leaks.

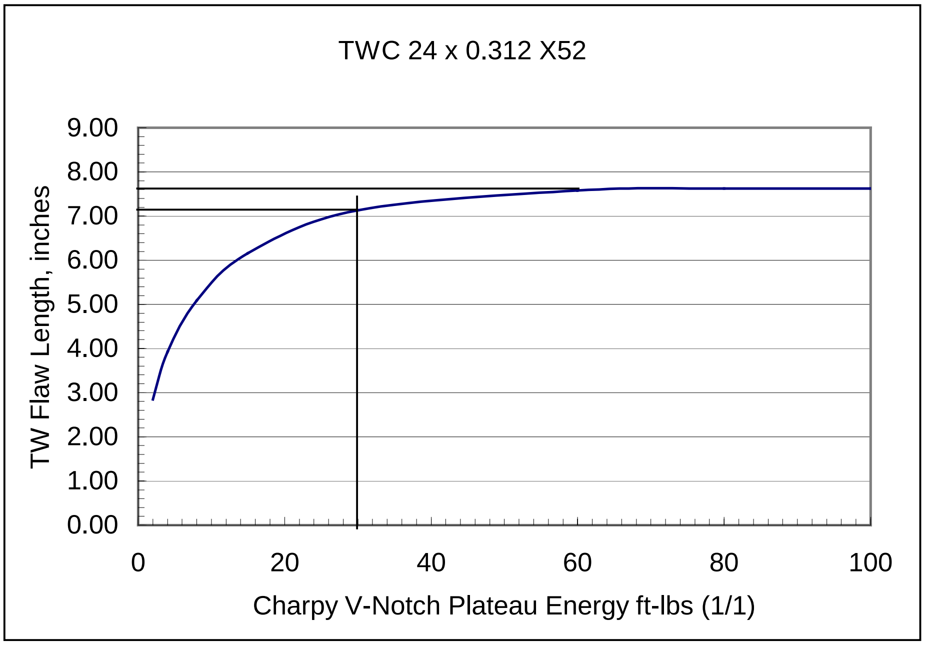


**Figure 10. Through-Wall Flaw Length Versus Charpy Energy**

Fracture toughness tests (Charpy V notch) were also conducted on the longitudinal seam weld. Unfortunately, the tests were not conducted to a high enough temperature to define the toughness level. The results do indicate that the seam toughness is not as good as the base metal, which is typical of all line pipe. This emphasizes the need for a high-pressure hydrostatic test of this pipeline to test the seam for anomalies, as the other inspections that have been performed only were capable of detecting flaws in the pipe body.

## Impact of an Incident on Adjacent Pipelines

There is a risk that the rupture of a natural gas pipeline could cause the failure of an adjacent pipeline when the pipelines are in close proximity. In the present situation there are two other liquid pipelines that are reasonably close as shown in Figure 1 and a third line that crosses the Rancho pipeline. The release of energy from the ruptured gas line is not adequate to cause sufficient ground motion to damage an adjacent buried line based on the authors experience, as the coupling of the released energy through the adjacent soil is poor and insufficient to rupture a pipeline that is near the ground surface. This is also verified by analysis and experiments[21] that have been conducted to explore the effect of blasting on pipelines. Therefore it has been concluded that failure of an adjacent line might be due to either physical

[21] E.D. Esparza et al, Pipeline Response to Buried Explosive Detonations, PRCI Catalog No. L51406 August 1981, American Gas Association.

damage of removing the soil support and overburden to the adjacent line if that can occur or to uncovering the line or subsequent thermal damage assuming the escaping natural gas fires but not due to the initial release of energy.

This risk has been addressed by estimating the depth of the crater formed and the width of the crater at the ground surface. If the crater width is such that it would totally expose the adjacent line then the adjacent line might rupture. If the top of the adjacent line is only exposed then radiation from a fire could soften the adjacent pipeline steel and cause it to fail. In this case, remedial measures may be necessary to assure an adjacent pipeline is not affected.

Two equations have been used to calculate the crater width and rupture crater radius. Both crater width and rupture crater radius extends perpendicular to the pipeline axis. The length of soil removed along the line is a function of how long a time period the gas exits from the pipeline. The model assumes that the width does not increase with time as the gas jets from the pipe.

Following the determination of the crater width, an assessment of the effect of thermal radiation will be performed.

### *Determination of Crater Width*

Two studies have been located that address the issue of crater depth and width. One study[22] was conducted sponsored the gas transmission company in the Netherlands and was conducted by Delft Hydraulics. The other study[23] was conducted by Battelle that built on the Delft study to assess crater depth and width and which also addressed the potential for softening of an adjacent pipeline due to heat radiation. The equations that have been developed are empirical equations that do not incorporate any soil parameters as the existing soil parameters refer to the behavior of soils over long periods of time and are do not take into account the transient behavior of soils under impact or dynamic loading. Appendix A presents the equations and constants that have been used in determining the crater width and depth from the PRCI Report.

The first step was to assess the crater width for a range of soil conditions for a 24 inch diameter pipeline with a depth of backfill cover of 30 inches[24]. (30 inches is the minimum depth of cover required in the Part 195 and 192 requirements for pipelines.) (Note that if the depth of backfill is less than 30 inches the crater widths will be less than calculated leading to a reduced likelihood of pipeline interaction.) Using the equations in Appendix A, the effective crater widths were calculated to be as shown in Table 6. The crater width is the total width from one side to the other and therefore the distance that would be effective to an adjacent pipeline is one-half of the crater width.

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[22] Reference 1. Prediction of the Crater Caused by An Underground Pipeline Rupture, W. Schram, N.V. Nederlandse Gasunie, Groningen, Netherlands, May 1997.
[23] Reference 2. Line Rupture and the Spacing of Parallel Lines, B.N. Leis, S. Pimputkar, N. Ghadiali, and M. Grassi, Pipeline Research Committee International Project PR 3-9604, June 1999, available from www.technicaltoolboxes.com.
[24] Kinder-Morgan was queried on the depth of cover of the Rancho pipeline and indicated that where ever the line was exposed they have increased the backfill to be in compliance with Part 192.

**Table 6. Effective Crater Widths for 24 inch Diameter Pipe With 30 inches of Soil Cover.**

| Soil Type | Coefficient w | Crater Width, W, feet |
|---|---|---|
| sand or dry mixed soil | 1.1 | 29.7 |
| mixed soil or gravel | 1.75 | 33.1 |
| humid mixed soil, clay or rock | 2.7 | 46.4 |

***Determination of Rupture Crater***

The following equation was developed by Battelle in Ref. 2 to define the radius of a crater in the event of an explosive rupture. In many respects the rupture crater diameter and crater width are similar.

In the following equation, the nomenclature is the same as in Appendix A and the values are in metric units.

$$R_w = \left[(0.64(D_p^3 p_o)^{2/3} + 0.65D_c(D_p^3 p_o)^{1/3} - 0.83D_c^2\right]^{1/2}$$

Substituting $D_p$ = 0.61 m (24 inch), $p_o$= 46.6 bar (676 psig) and $D_c$=0.76 m (30 inch), the crater radius is calculated to be 27 feet, which is a diameter of 54 feet similar to the value for the humid soil radius of 23 feet (half the crater width of 46 feet in Table 4).

It should be noted that the calculated crater widths for the natural gas pipeline do not apply to any of the liquid lines. The reason is that the natural gas is compressed and the liquids are not compressed. This means that in the event of a rupture that a large amount of energy will be released as the natural gas expands. Since the liquid in a liquid pipeline are not compressed, there is very little energy released in the event of a rupture. Thus the concern for affects on adjacent lines only applies to the Rancho natural gas pipeline.

***Assessment of Situation on the Rancho Pipeline***

A sketch has been made to illustrate the effect of a 27 foot crater half width or radius. Figure 11 shows that for the 27 foot crater half-width that for an adjacent pipeline to be partially exposed it would have to be located within about 14 feet of the Rancho pipeline for the worst-case soil conditions. For the pipeline to be completely exposed it would have to located several feet closer still. This is closer than pipelines are typically placed (usually 25 feet) and indicates that there is a very remote chance that the rupture of the Rancho natural gas line removing the overburden would expose an adjacent line to sufficient force to cause its rupture.

The City of Austin developed maps of the Rancho (natural gas), Phillips (natural gas liquids) and Longhorn and Koch pipelines in the utility corridor through south Austin. These maps are presented in Appendix B and were reviewed to define the lengths of adjacent pipelines that were within 50 feet[25] of each other. Table 7 lists and identifies the 10 locations that were found along the pipeline where lines were within 50 feet of each other along with an indication of the

[25] The 27 foot spacing of pipelines has been increased to a 50 foot spacing for these maps since they were generated with GPS equipment to account for the GPS error band.

number of houses nearby. Table 7 indicates that a 50 foot line proximity exists for 17125 feet or 3.2 miles with several long sections having a number of houses within the 431 ft impact zone.

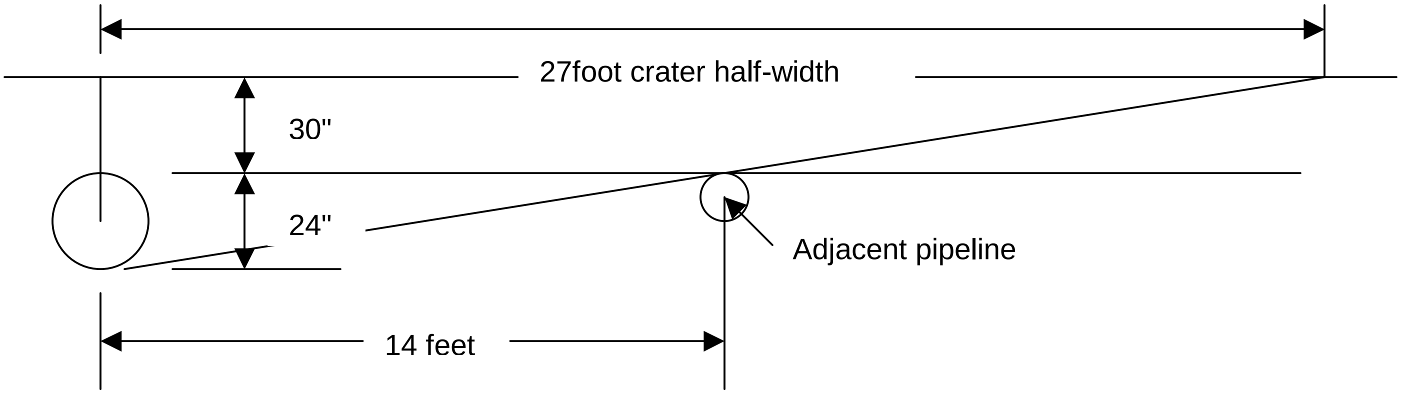


**Figure 11. Sketch of Crater Width Effect on Adjacent Pipeline**

**Table 7. Rancho Locations Within 50 feet of Another Pipeline**

| **No.** | **Location** | **Length of line Within 50 ft** | **Houses within 440 ft.** |
|---|---|---|---|
| 1 | 1150 feet west of Wagon Rd. | 100 | 1 |
| 2 | West end 150 ft. west of 290 and parallel to Spring Valley | 3200 | |
| 3 | West end 500 feet east of 1826 | 2200 | 13 |
| 4 | West end 100 feet west of Leo | 5400 | Numerous |
| 5 | West end 2400 feet west of First St., which includes a crossing of the Phillips Pipeline | 1200 | 1 |
| 6 | Crossing of the Phillips Pipeline 1200 feet east of Congress | 100 | None |
| 7 | West end 250 feet east of Bluff Springs | 1800 | Numerous |
| 8 | East end 700 feet east of William Cannon | 2725 | Numerous |
| 9 | Crossing of the Koch Pipeline 350 feet east of Bain | 100 | None |
| 10 | West end 400 feet east of Tower | 250 | 4 |
| | Total | 17125 | |

Table 8 provides information on the characteristics of the adjacent pipelines. The fact that the Rancho Pipeline crosses above the other lines indicates it is unlikely that rupture of the Rancho natural gas pipeline would affect the liquid lines.

**Table 8. Characteristics of Adjacent Pipelines**

| Name/Company | Diameter. inch | Wall Thickness, inch | Grade | Operating Stress, % SMYS | Products |
|---|---|---|---|---|---|
| Phillips* | 10.75 | 0.250 | X42 | 60 | Natural Gas Liquids |
| Longhorn** | 18<br>18 | 0.281 & 0.312<br>0.375 | X42 (1950)<br>X65 (2002) | 72<br>36 | Petroleum Products |
| Koch*** | 16 | 0.250 | X65 (1990) | 71 | Petroleum Products |

Notes: * Phillips line crosses under the Rancho line twice with a separation of 24 inches.
** Longhorn line does not cross the Rancho line.
** Koch line crosses under the Rancho line with a separation of 24 inches.

### *Thermal Effects on Adjacent Lines*

In spite of the knowledge that the adjacent lines would probably not be exposed in the event of a rupture of the Rancho line, an assessment was made of the likely thermal effects of a firing jet on an adjacent pipeline if should become exposed to the radiation. Also, if the pipeline is not exposed the cover will probably be reduced and this could allow some of the heat to reach the line. An assessment was therefore conducted to see what would be expected to happen if the line was exposed to high temperatures.

A follow on study to Ref. 2 at Battelle indicated that adjacent lines that have gas or liquid flowing in them that are 25 feet apart with one line jetting gas that is on fire would increase the temperature of the exposed pipeline. This assumes that the crater formed by the ruptured pipeline exposes the pipe surface of the adjacent pipeline to radiation from the ignition of the gas in the ruptured line. Calculations indicated that the temperature of the pipe steel in the adjacent exposed line could be as high as 572 to 662F (300 to 350C) when gas or liquid is flowing in the adjacent line. If the adjacent pipeline is shut down, the temperature will be much higher than calculated above and may cause failure.[26]

As shown in Table 8 the adjacent pipelines are X42, X60 and X65 grades. The following section assesses the pressure stress in the adjacent pipelines compared to the yield strength at 675F. High temperature strength data are presented in Figure 12 from two sources. The top curve presents the temperature derating requirements for X42 grade pipe that exist in the Federal Regulations for natural gas pipelines, 49 CFR Part 192.115. At room temperature, the yield strength is 42,000 psi. The bottom curve represents tensile tests that were conducted by the author on A106B pipe which is a plain carbon steel that has not been cold worked in the formation of the pipe and therefore its room temperature yield strength is lower but the trend of the data is the same. The observation that the two curves are essentially parallel allows extrapolation of the X42 curve to higher temperatures.

[26] It has been the author's experience that pipeline operators would not be expected to shut down a pipeline unless there is an indication of potential danger. Normally, lines are not shut-in immediately in this type of situation as the operator of an adjacent line is not aware of the problem on an adjacent line until some time after the event has occurred and by then more information is available on which to make a decision.

The highest hoop stress that could exist in an adjacent X42 pipeline is 72% SMYS which creates a stress of 30,240 psi. The lowest yield strength that can be expected at 675F (used in place of 662F) according to Figure 12 for X42 pipe is between 32,000 and 34,000 psi. Therefore, the imposed stresses are lower than the reduced yield strength at temperature and would be safe if it has a 25 or more foot spacing from the ruptured line. The higher grades of pipe, X60 or X65, will also be safe as the stress in the pipes will be 43,200 psi or 46,800 psig at a 72% design factor and the yield strengths were calculated (similar to Figure 12) to be 48,000 psi and 53,000 psi respectively. In both cases, the stress levels are below the yield strengths at temperature. Therefore, the adjacent pipelines were found to safe from thermal effects if the pipe is uncovered and the adjacent pipeline is not shut down. The above calculations assume that the flow is maintained in the adjacent lines as the flow removes the heat input into the pipe

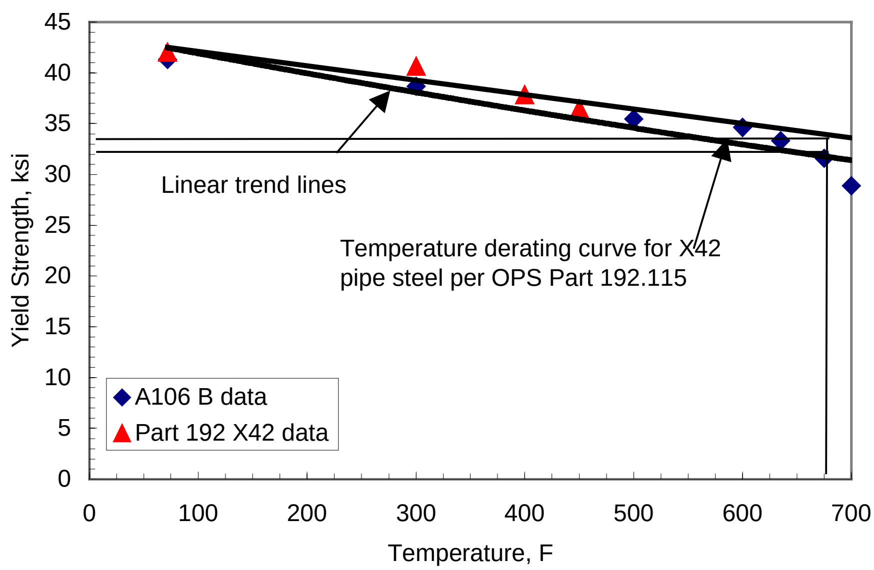


**Figure 12. Temperature Effects on Line Pipe**

***Overall Assessment of Adjacent Lines***

There are two risks from adjacent lines, one is that the failure of one could cause an adjacent line to fail by exposing it to the jetting gas and secondly that the natural gas line fails and ignites which could heat the adjacent pipe steel causing it to weaken and fail. The assessment conducted indicated that there is a low risk that the adjacent pipelines would be affected from either the rupture of the Rancho pipeline or the thermal effects that might follow assuming the adjacent pipelines are not shut down.

## Environmental Impact

The effect of an incident on the Rancho pipeline on the environment will be minimal because natural gas is lighter than air and will rise into the atmosphere. In the event of a large release of gas from the line, the soil above the line will be removed and the gas will dissipate into the atmosphere. As the release size decreases, the amount of soil removed will decrease until none is removed but the gas will still penetrate through the soil and disappear.

The environmental impact would be more severe if an adjacent petroleum products line should become involved and that is one reason that this was addressed. Fortunately, the potential for that to occur appears to be remote and an unlikely event.

# SAND HILL LATERAL REVIEW

The Sand Hill lateral is a 5.1 mile lateral from the Rancho Pipeline to the City of Austin Sand Hill generating plant. The lateral starts just west of the Garfield regulator and proceeds north to the generating station. The lateral is being constructed of new pipe to current 49 CFR Part 192 requirements. The pipe, construction practices and the hydrostatic test pressures have been reviewed.

## Sand Hill Pipe Characteristics

Appendix C lists the pipe mills, diameter, wall thickness, grades and pipe properties of the pipe to be used in the Sand Hill Lateral. Presently in the US, the supply of 20 inch diameter pipe is very limited and therefore this pipe had to be purchased from two pipe mills to obtain sufficient quantity of pipe. Table 9 presents the pipe sizes and properties.

**Table 9. Sand Hill Pipe Data**

| Quantity, feet | Mill | Wall Thickness, inch | API Grade | Operating Stress, %SMYS | Min./Max. Test Stress , %SMYS (1509/1622 psig) | Avg.CVN Plateau Energy, ft-lbs (2/3 t) | TW Flaw Length at operating stress, inch |
|---|---|---|---|---|---|---|---|
| 3000 | American Steel Pipe | 0.312 | X60 (PSL2) | 36 | 94/101 | 158 | ~20 |
| 5500 | STUPP | 0.250 | X65 (PSL2) | 42 | 94/101 | 54.3 | ~11.5 |
| 14,000 | STUPP | 0.344 | X65 (PSL2) | 30 | 74/80 | 101 | 8.4 |
| 4500 | STUPP | 0.500 | X60 (PSL2) | 23 | 58/62 | 108 | 11.8 |

The pipe metallurgy and physical characteristics substantially exceed minimum requirements in all categories. All of this pipe is high fracture toughness and the critical through-wall flaw lengths (rupture to leak dividing lengths) at the maximum operating pressure range from 8.4 to 20 inches long in the axial direction and completely through the pipe wall thickness. These are very large flaws and integrity of this line is assured by the high toughness and low operating stress levels.

## Class Location of Lateral

The Class location of the Sand Hill Lateral currently is Class 1 and 2 based on aerial surveys of the area. To provide for future development, Kinder-Morgan has decided to construct the pipeline to a Class 3 location which means that the maximum design stress for the pipe wall thickness is 50% SMYS.  As can be seen in Table 9, the planned operating stress ranges from 23 to 42 % SMYS for this line and therefore is even more conservatively designed than allowed by the federal code 49 CFR Part 192.

## Review of Construction Specifications

Noel Duckworth reviewed the 20" lateral construction specifications with Ron McClain, Alice Weekly, and "Chief" Saddler and the following is a brief synopsis of the key elements relating to installing the pipeline with the high standards that are expected within this environment:

- The pipe is coated with 0.012"- 0.016" of fusion bonded epoxy coating, which is an excellent choice for this environment.
- The weld joints will be field coated with a 3M-epoxy coating to assure compatibility with the FBE coating applied to the body of the pipe.
- There are 3 road bores and a 1200' directional drill under Onion creek that will be coated with Powercrete®, an epoxy based polymer concrete, which is the coating of choice for directional drilling and road boring.
- Where required, the ditch bottom will be padded with sand bags and other soft material either brought in to the location or crushed and sifted on site. This is standard procedure in the Industry to avoid coating damage during construction of the pipeline as well as from movement of the pipe within the ditch after commissioning.
- All pipe will be tested for holidays in the coating utilizing an electronic testing device (Jeep). There will be an inspector on site during all placement of pipe in the ditch and if he suspects that damage might have occurred to the coating, then he will require that the contractor re-inspect the pipe for holidays. This is an important integrity management process.
- There will be 100% X-Ray of all welding on the pipeline and all welds must maintain strict compliance with API 1104.
- All operations throughout the construction process will be inspected with third-party inspectors provided by Universal Ensco and Gulf Intersate Engineering from Houston. These companies are known to have good credibility in the field.
- There will be 6 inspectors on the project at all times and this number is certainly adequate to assure a quality product.
- In addition to the inspectors, there will be 2 survey crews documenting the precise placement of all welds and other elements of the pipeline.
- The final phase of construction will be hydrostatically testing to confirm the strength of the completed pipeline as well as to provide a leak test to assure no leakage. The pipeline will be hydro-tested to 93% of SMYS on the weakest joint in the system (structurally) and they have assumed that the weakest joint will be at the highest elevation. This assures a minimum 50% to 93%SMYS test on all joints.  (Note, the wide range of SMYS is because of the wide range of wall thickness and two strength grades X60 and X65.)  Overall the test pressure to be applied to the lateral is 2.2 times the operating pressure, which is the same test margin that will be applied to the existing Rancho Pipeline.  The test duration will be for 8 hours. There is very little elevation change in this short section and thus the whole 5.1 miles can be tested at once. It should be noted that the 1200 foot horizontal drill section will be pre-tested prior to installation so therefore, that section will be tested twice. This test complies with all Federal and State codes.

- We could not identify any elements of the pipe design, construction specifications or test practices that did not meet or exceed Federal and State Codes as well as the standards of care in the Industry.

Overall, this proposed lateral is somewhat unusual because of the limited availability of line pipe as it is significantly over designed and the construction specifications are of the highest quality.

# OPERATING PLAN ASSESSMENT

## Pressure Profile

A concern that the authors had was whether there would be large variations in pressure in the Rancho Pipeline. This could lead to growth of small anomalies to the point where they could become injurious. Therefore the pressure profile and variations were explored with Kinder-Morgan.

The gas supply for the Rancho Pipeline is from a Kinder-Morgan pipeline that runs from Laredo to Houston with a tap at Katy. The Katy tap feeds the Rancho Pipeline through a regulator that maintains the pressure at or below 811 psig, which is the MAOP for this section of the Rancho line -a Class 2 location. The gas flows northwest toward Austin where it reaches the Garfield regulator, which decreases the pressure to 676 psig as it feeds gas into the Rancho Pipeline segment within the ETJ limits of the City of Austin. The calculated pressure variations on the downstream side of the Garfield regulator due to changes in demand of the Sand Hill generating station are from 676 to 674 psig. The pressure at the delivery end of the Sand Hill lateral was calculated to vary between 676 and 655 psig. At the northwest end of the Rancho Pipeline (LCRA), the calculated pressure range is from 675 to 671 psig under current conditions. The Rancho Pipeline west of the Sand Hill Lateral will provide a reservoir of capacity for the power plant, supply two TGS taps, and potentially deliver gas to another power plant facility in the area.

Future deliveries to another power plant facility may cause the pressure to fluctuate more but the magnitude and frequency of the pressure fluctuations will be relatively small. Thus, the author's have concluded that the threat of measurable, cyclic defect growth in this natural gas service as previously described is very low.

## SCADA Review

SCADA (Supervisory Control and Data Acquisition) has often been thought of by people outside of the pipeline industry as a system to detect leaks in a pipeline. This is not the situation. In a pipeline system, the SCADA system provides data that is necessary to control the operation of a pipeline.

As applied to liquid pipeline systems, a leak detection capability is an add-on to the SCADA system. Leak detection systems on liquid pipelines typically are capable of finding relatively small leaks that are on the order of 1 to 1.5% of the flow in a line. This results because the liquid in the line is non-compressible and the mass flow-in must equal the mass flow-out within a small tolerance unless there is a leak in the line. Also, a leak in a liquid line will cause a pressure decay assisting in the detection of a leak. In a natural gas pipeline, the gas is compressible and small leaks do not decrease the pressure making it difficult to detect small leaks based on pressure drop. If the leak is large enough, then the pressure will drop and this is why Kinder-Morgan has installed automatic closing block valves on the Rancho pipeline. These valves are set to close when a pressure drop in the gas of 15 psi occurs in 1 minute. This provides a means of detecting and quickly closing the block valves in the event of a large leak.

The point of this discussion is that when the pipeline was converted the SCADA system had to be totally changed from a liquid based to a gaseous-based system. From the information supplied which is presented in Appendix D, the SCADA system being applied to this pipeline is the same as applied to all of the Kinder-Morgan natural gas pipelines and appears to be quite adequate. The SCADA is about 4 years old but has been continually upgraded as new features become available and therefore the age is not a discriminator of the status of the system.

Two inquiries that were made by the authors that could affect the operation of the pipeline but not its safety are: 1) does the SCADA system monitor the automatic closing valves so that if one accidentally closed the SCADA system would indicate an alarm to the operator and 2) does the operator have the ability to remotely open the valve or does someone have to visit the site to inspect the local condition before it can be reopened. The answer to the first concern is that the SCADA system does not monitor the automatic closing valves. Therefore, in the event of a valve closure someone would have to be dispatched to find out which valve is closed and then investigate to find out why it closed. This could affect the supply of gas to the power plant if a valve in close proximity closed and some time was required to assess whether the valve could be reopened. These valves are not set up for remote operation and therefore it is necessary to have a person manually reopen the valve.

Overall, this SCADA system is more than adequate for operating the pipeline but cannot find small leaks. For this reason, the automatic closing block valves have been installed.

## Integrity Management Plan

Kinder-Morgan provided a copy of their Pipeline Integrity Management Program to illustrate how they manage the integrity of their pipelines. The K-M management program indicates

> *"The Pipeline Integrity Management Program provides for optimal maintenance of existing pipeline facilities by identifying an assessing the historical, existing and predicted pipeline condition. This is accomplished by systematically evaluating precursors; pipeline attributes or parameters such as operating conditions environment, adjacent land use and pipeline attributes that could lead to or contribute to loss of containment."*

In summary, the K-M program involves the following:

> *"The Pipeline Integrity Management Program uses the company's Operating and Maintenance Procedures together with pre-assessment tools* (see Figure 13) *to generate annual data for pipeline integrity analysis and remediation on every pipeline segment. Field and corporate personnel integrate the data with the PODS database (pipeline attributes), historical surveys, inspections, operational data, etc. The results are analyzed with several different techniques to quantify the amount of risk associated with the identified integrity threat. From that analysis, the appropriate tool or tools are selected from the assessment toolbox (in-line inspection, hydrostatic test, other*

*technology or a combination). Remediation is performed based on test results and analysis. When remediation is completed, Engineering records are submitted to the corporate office. Pipeline segment integrity is confirmed until the following year when the process is initiated again."*

The Kinder-Morgan IMP contains all of the necessary steps to identify line segments that need remediation. The annual data that is collected and reviewed includes all of the necessary items. Also the remedial measures are those that could be used to restore integrity to pipeline segments depending on the condition that is being addressed. Kinder-Morgan has developed written procedures for collecting data, which will result in standardized data. Since this is a new line that will be added to the Kinder-Morgan natural gas pipeline segments, the specific steps that will be taken with this line have not yet been defined. After all of the data have been collected, the *PIRAMID*™ Risk Estimation and Evaluation program[27] is run on all of the pipeline segments. This program evaluates the 22 threats that are listed in Table 4 and establishes a risk ranking and a total impact for each segment of pipeline. Based on this, Kinder-Morgan will make the determination of which lines will be addressed.

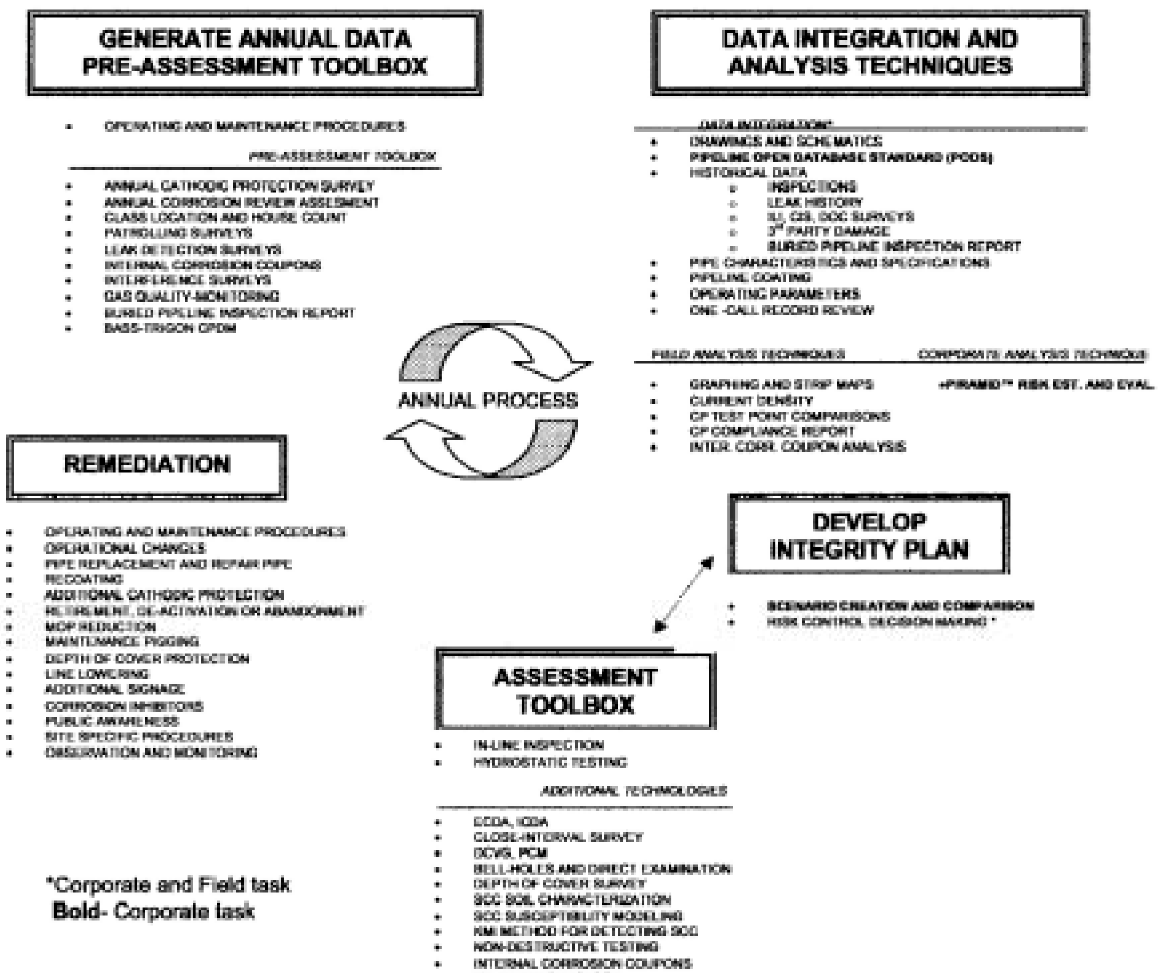


**Figure 13. Kinder-Morgan Data/Assessment Tools**

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27 This program was developed by C-FER. It calculates the probability of failure and consequence impact estimates based on pipeline attributes and historical data.

In January of 2004, OPS issued an addition to 49CFR Part 192 addressing integrity management of gas pipelines in high consequence areas (HCA's), which includes gas pipelines in Class 3 locations. Therefore, most of the Rancho pipeline within the City of Austin ETJ and the Sand Hill Lateral will be required to be addressed by this new rule. The rule requires the operator to develop a written plan for their pipelines in HCA's to describe the threats and conduct a baseline assessment followed by a reassessment within seven years. The baseline assessment must be selected from the following four methods and must be suitable for the defined threats:

1. Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME B31.8S, section 6.2 in selecting the appropriate internal inspection tools for the covered segment.
2. Pressure test conducted in accordance with subpart J of this part;
3. Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929.
4. Other technology than an operator demonstrates can provide an equivalent understanding of the condition of the line pipe.

Of all the potential causes of incidents, see Table 4, mechanical damage from construction equipment is one of the greatest concerns as this was the cause of the previous incident on the Rancho pipeline in the Austin area. One tried and proven method of minimizing damage to pipelines from third party excavating is to provide, on a continual basis, complete awareness relating to the location of the facilities as well as the potential consequences of damaging a pipeline. Rancho has done a comparatively thorough job of marking the pipeline as it traverses the ETJ. It is Kinder Morgan's stated position that they will be continually upgrading the marking system as potential deficiencies are identified.

The Kinder-Morgan IMP complies with CFR Part 192.705, which states that the pipeline must be patrolled at least twice a year in a class 3 location. This is too infrequent to be of any tangible value in this major growth environment. The authors believe that more frequent monitoring for construction activity near the line is warranted because of the number of houses in the close proximity to the pipeline. Kinder Morgan has stated that they will have personnel permanently stationed in the Austin area and it is obvious that they will be out along the pipeline within the ETJ on a regular basis. Therefore, it would seem that a goal or aim of patrolling the pipeline in the Austin ETJ region biweekly could be achieved with minimum planning. Our recommendation is that Kinder Morgan should develop a plan that sets as its goal patrolling the pipeline biweekly within the ETJ for the first year of operation and then adjusting the frequency based on actual needs as established for this particular environment and excavation activity level.

Also, there is an opportunity for the City of Austin to show their support for the proven and effective One Call System. If prudent, the City should seriously consider implementation of ordinances (laws?) that impose significant penalties for contractors performing any form of excavation without first contacting the One-Call System. Further, there should be equally damaging penalties imposed on utility operators that do not respond properly when "One-Call" notifies them of activity near their facilities.

There is no way to absolutely prevent mechanical damage but all of the possible efforts should be implemented as mechanical damage frequently leads to ruptures whereas many of the other types of anomalies in a low stress pipeline such as this one will lead to leaks. In this regard, Kinder-Morgan supports the one-call system and has a public information and coordination plan with local responders in an emergency. This information is presented in detail in Appendix F. The damage prevention and public education procedures focus on one-call systems, marking of pipelines, inspection of damaged pipe, an educational program for the public, and emergency response coordination. The educational program for the public consists of brochures mail to the public located within 660 feet of their transmission pipelines. The brochures address the following issues:

- How to work around our pipeline,
- How to identify where the pipeline is located,
- What is a pipeline emergency,
- How to recognize a pipeline leak near a pipeline right of way,
- What to do in a pipeline emergency,
- Emergency action procedures for public safety officials, and
- Kinder-Morgan's emergency phone numbers.

Overall, the authors have been impressed that Kinder-Morgan is willing to implement additional safeguards to make sure pipeline integrity is maintained and the public is protected.

# RECOMMENDATIONS

The recommendations included in the report are summarized in this section.

**Kinder Morgan recommendations**

- Kinder-Morgan should develop a plan that sets as its goal patrolling the pipeline biweekly within the ETJ for the first year of operation and then adjusting the frequency based on actual needs as established for this particular environment and excavation activity level.
- It is recommended (and implemented by Kinder-Morgan) that a pressure test be conducted by increasing the pressure in each test section in three steps. The goal of the three steps is to provide time for the pressure to stabilize at each pressure level and time for failures to occur.
    - The first step is to pressure each test section to 90 to 100% SMYS and hold it for 10 minutes.
    - If no failures or leaks occur, the second step is increase the pressure to 95 to 105% SMYS and hold it for 10 minutes.
    - Again, if no failures or leaks occur, the third step is to increase the pressure to 100 to 110% SMYS and hold it for 10 minutes.
    - If no failures or leaks occur, decrease the pressure to 70% SMYS at the high elevation point and hold for the required leak check period. This relatively low pressure is the minimum federal required pressure for the leak check and will assure that no anomalies grow during the leak check.
- It is recommended that Kinder Morgan perform a Close Interval Survey on the pipeline between I-35 and the Eastern ETJ prior to the end of 2003. Further, it is recommended that they should complete the required cathodic protection system remediation and corrosion abatement as dictated by the survey prior to the end of 2005.

**City of Austin Recommendations**

- If prudent, the City should seriously consider implementation of ordinances that impose significant penalties for contractors performing any form of excavation without first contacting the One-Call System. Further, there should be equally damaging penalties imposed on utility operators that do not respond properly when “One-Call” notifies them of activity near their facilities.

# CONCLUSIONS

The assessment of the Kinder-Morgan Rancho pipeline from crude oil to natural gas service has reviewed:

- The original design and service performance,
- The Kinder-Morgan integrity assessments involving in-line inspection and pressure testing,
- Consequences in the event of an incident,
- Sand Hill Lateral pipe and construction, and
- Kinder-Morgan operational review.

Where appropriate, all assessments were made relative to:

- Federal Regulations as specified in 49 CFR Part 192 of the Federal Registry,
- API 5LX Specification for Line Pipe, 1948 and 1953 edition.
- ASME B31.8, Gas Transmission and Distribution Piping Systems,
- ASME B31.8S, Supplement to B31.8 on Managing System Integrity of Gas Pipelines
- Texas Administrative Code, Title 16, Part 1 Railroad Commission of Texas, Chapter 8 Pipeline Safety Regulations, Sub Chapter B Requirements for Natural Gas and Hazardous Liquids Pipelines and
- The “Standard of Care” prevalent in the Industry for similar environments.

The Rancho line is composed of 24 inch diameter x 0.312 and 0.344 inch wall thickness, API 5LX X-52 pipe produced by A.O.Smith in 1952 using a flash welding process for the longitudinal seam. The seam welding process produced a seam weld that is similar to a low frequency ERW process that was involved in an alert notice from the Office of Pipeline Safety advising that the pipe is deemed susceptible to seam failures unless an engineering analysis shows otherwise. Therefore, special attention has been focused on the integrity of the flash weld seam.

There are two very positive “pipeline strength” issues as a result of converting from liquid to natural gas service. First, the change from liquid to natural gas service has reduced the operating pressure from a maximum of 973 psig in liquid service to a maximum of 676 psig in natural gas service. This is because natural gas pipelines are required to operate at reduced pressures as a function of population density and pipelines in liquid service do not have these regulatory pressure restraints. Secondly, this pipeline will operate with a large reduction in cyclic pressure amplitude and frequency. Most longitudinally oriented pipeline defects can grow in service if subjected to a large number of large pressure cycles. Liquid pipelines can typically have high frequency, high amplitude pressure cycles (0 to max. pressure cycles are not unusual) depending on methods of operation in fluctuating “demand” situations due to the non-compressible fluid in the pipeline. Natural gas pipelines have relatively constant flow and the “demand” variances are dampened by the compressibility of the medium transported with the result that pressure fluctuations normally are 10 to 15 percent of the maximum pressure.

The examination of the prior incident records for the Rancho pipeline revealed that 10 incidents had occurred with three of these associated with the pipe caused by defective pipe, external corrosion and mechanical damage. The other seven incidents were associated with tank farms, pumping stations and internal corrosion at a delivery point all of which have been eliminated in the change from liquid to natural gas service. The pipe body was found to have a tolerance for anomalies in the body of the pipe that is 94 percent of the theoretical maximum for pipe of this size and grade. The weld seam was not as tolerant of flaws as the pipe body, which is typical of line pipe. Therefore, it was concluded that the pipe has provided excellent service and with proper maintenance, it would be expected to do so in the future.

The Kinder-Morgan integrity assessments have involved examining the results of an HSMFL ILI tool for hard spots, running a deformation tool, HRMFL tool for metal loss, and a hydrostatic pressure test of the complete line. The hard spot examination indicated that hard spot were found outside of the Austin area and were remediated. The deformation tool confirmed that there were no incidences of deformation that required attention, and the HRMFL tool found a number of areas of metal loss that were removed. The Rancho line was originally pressure tested to stress levels of 56 to 83% SMYS. The current proposal by Kinder-Morgan was to test to stress levels of 90 to 100% SMYS. After reviewing the proximity of houses to this line, the authors recommended that the test pressure (stress level) be increased to the maximum level possible and recommended a stress level of 100 to 110% SMYS, which was accepted by Kinder-Morgan. The maximum test pressure was set as 1) the pressure at which a double stroke is achieved in the pressure test to eliminate the possibility of yielding the pipe, 2) the pressure at which a failure occurs in the weld seam so long as the pressure is above 90% SMYS, and 3) a pressure of 110% SMYS.

The pressure test was completed with one failure in one section, with the failure occurring outside of the Austin ETJ limits. The failure occurred approximately 12 miles east of the eastern Austin ETJ. Within the Austin ETJ limits, Sections 2 and 3 reached stress levels between 100 and 110% SMYS as desired. Within the Austin ETJ, the stress in the pipe in Test Section 4 was between 94 and 101% SMYS. This stress level is higher than the test stress levels originally proposed by Kinder-Morgan. The pressure test results are very significant as they indicate that the integrity of this pipe is very good. The pressure test assessed the integrity of the longitudinal weld seam (as well as the rest of the pipe) however the body of the pipe had been inspected using the deformation and HRMFL tools. The test thus also validated the ILI inspection results. The fact that only one failure occurred in testing the complete 130 mile line to a pressure that was up to 170 percent of the original 1953 hydrotest pressure provides assurance of the integrity of the longitudinal weld seam and the pipe body indicating that this pipeline has been well maintained during its past 50 years of service.

The potential consequences of an incident were reviewed. The results indicate that the impact zone was calculated to be 431 feet from the pipe centerline. This distance is the 1% lethality distance for radiation from a flaming jet assuming a double-ended rupture of the gas line. This reinforces the need for the integrity of this line to be maintained at the highest level possible as the line enters service and also during operation.

The assessment examined the effect of a natural gas line rupture on other pipelines in the utility corridor. The conclusion of the analysis is that it is very unlikely that rupture of the natural gas line would cause the other lines to fail, as they are not close enough. Secondly, even if an adjacent pipeline should be uncovered, the pipe could withstand the heat of a jet fire without rupturing so long as the flow is maintained in the adjacent lines. There are three pipelines that cross under the Rancho pipeline and therefore rupture of the Rancho pipeline should not cause a crossing line to rupture.

The Sand Hill lateral is being constructed of new pipe and the stress level in the pipeline ranges from 27 to 43% SMYS and is a Class 3 location to account for future population encroachment. The fracture toughness of the new pipe is outstanding. The lateral will be pressure tested to 58 to 101% SMYS. (The wide range is due to the fact that four different wall thicknesses are involved in this lateral due to difficulties encountered in obtaining line pipe.)

Kinder-Morgan's integrity plan requires reassessment of the pipeline every year. OPS Part 192 requires in-line inspection of this pipeline every seven years since it is a Class 3 location. Kinder-Morgan also will monitor the cathodic protection requirements for the pipeline to make sure that corrosion is being controlled. The one area of potential concern is the frequency of patrolling surveys (visual surveillance). Kinder-Morgan is only required to patrol the line twice a year by code but our recommendation is to patrol the line bimonthly in the first year and more or less frequent after that, depending on the need as established in the first year. Line patrol is one way to monitor the pipeline, the other is to rigidly reinforce the one-call system to make sure that contractors do not dig without contacting Kinder-Morgan. A highly disciplined combination of the two can be very effective.

Overall, the authors expect that with the successful completion of all of the mitigative efforts described herein coupled with proper maintenance, this line should provide excellent incident free service.