THE MISSOURI PUBLIC SERVICE COMMISSION

PIPELINE SAFETY PROGRAM

REPORT

April 2011

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THE MISSOURI PUBLIC SERVICE COMMISSION
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I. EXECUTIVE SUMMARY

This report provides a summary of the Gas Safety Program in Missouri as administered by the Missouri Public Service Commission (Commission). In addition to summarizing the normal activities performed by the Commission's Gas Safety/Engineering Staff (Staff), this report discusses pipeline replacement programs, federal and state safety regulations, and the Commission's enhanced inspection efforts. This report concludes with recommendations to improve the Gas Safety Program in Missouri.

For Calendar Year 2010, Staff conducted 65 comprehensive office and field inspections in jurisdictional systems/inspection units. In addition, some Commissioners, Commission management personnel and Staff participated in special, comprehensive leak surveys in random areas of five of the jurisdictional systems. The surveys found minor above-ground leaks and one non-hazardous underground leak.

Staff filed two motions to establish cases for investigation of gas safety incidents. The first, File No. GS-2011-0245 (established February 3, 2011), was filed in response to a reportable incident[1] that occurred on January 8, 2011, in Pine Lawn, Missouri, an area served by Laclede Gas Company of St. Louis. The second, File No. GS-2011-0248 (established February 7, 2011), was filed in response to a reportable incident that occurred on February 2, 2011, in Kansas City, Missouri, an area served by Missouri Gas Energy. Staff continues its investigation of both incidents.

As explained in more detail throughout the report, Staff makes the following recommendations or observations for improvements to the Gas Safety Program in Missouri.

a. Staff will continue to monitor local distribution companies' (LDCs) and municipal systems' implementation of, and compliance with, the U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration Transmission Pipelines Integrity Management Program (Gas IM).

[1] Missouri Reportable Incident is an event that involves a release of gas and involves a death; a personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or estimated property damage, including cost of gas lost, to the gas operator or others, or both, of ten thousand dollars ($10,000) or more; or an event that is significant, in the judgment of the operator, even though it did not meet the above criteria. (See 4 CSR 240-40.020(4)(A) "Missouri Reporting Requirements")

b. Staff will evaluate operator plans that will be developed and implemented pursuant to the U.S. Department of Transportation – Pipeline Hazardous Materials Safety Administration Distribution Integrity Management Program (DIMP). Once implemented, Staff will continue to monitor the plans, review operations and applicability during inspections and make recommendations for changes in areas that need improvement.

c. Staff recommends the Commission introduce proposed excavation damage prevention legislation to make revisions to Chapter 319 to add provisions related to Commission investigation of possible violations by gas corporations, gas pipelines and municipal gas systems subject to the Commission's jurisdiction for safety purposes and to improve damage notification and reporting efforts.

d. Staff recommends the Commission promulgate rulemakings to adopt amendments to the Federal Pipeline Safety Regulations; require "real-time" reporting of each known "damage event"; require quarterly reporting of excavation notices received from the notification center; require implementation of performance measures applicable to all persons that perform underground facility marking; and require the implementation of quality assurance programs.

e. Reevaluate replacement programs and review older vintage cast iron, natural gas pipeline facilities with the possible goal of initiating specific long-term replacement programs.

f. Create an educational brochure or consumer bill of rights for landowners with property near high consequence area pipelines.

II. PROGRAM OVERVIEW

The Commission has jurisdiction over all intrastate gas pipeline[2] operators in Missouri, which include four intrastate transmission pipelines, seven investor-owned natural gas distribution utilities (six of which also have intrastate transmission pipelines and all of which have multiple operating districts/inspection units), forty-two municipally-owned natural gas distribution systems, one gas distribution system owned and operated by a private company on a Department of Defense facility at Fort Leonard Wood, and three pipeline systems that supply landfill gas (LFG) directly to customers that include a high school, a correctional facility gas-fired electric generation turbine and a large industrial customer. In total, the intrastate gas pipeline operators have 105 "inspection units" for purposes of the natural gas pipeline safety program's annual comprehensive inspection program which include:

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[2] "Intrastate gas pipeline" is a pipeline that operates within the State of Missouri borders and links the interstate natural gas pipeline network to local markets (LDCs and municipals).

- 26,682 miles of distribution main
- 693 miles of transmission lines
- 1,505,795 service lines

The Commission does not have jurisdiction over interstate natural gas transmission pipelines[3] or hazardous liquid pipelines. At the end of calendar year 2009, there were 3,858 miles of interstate gas transmission pipelines and 4,800 miles of interstate hazardous liquid pipelines in Missouri.[4] Safety jurisdiction of these pipelines is regulated by the U. S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA).

The Commission's natural gas pipeline safety program is carried out under a cooperative agreement with U. S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration (PHMSA). By participating in the cooperative agreement with PHMSA, the Commission receives grant funding for a significant portion of the Commission's natural gas pipeline safety program expenditures. For instance, the Commission was reimbursed for approximately 40% of costs in Calendar Year 2007 ($285,438) and Calendar Year 2008 ($313,807). Congress appropriated additional funding for the PHMSA pipeline safety grant program, and in Calendar Year 2009 the Commission was reimbursed for almost 70% ($607,271) of the Commission's natural gas pipeline safety program expenditures.

As a part of the natural gas pipeline safety program, the Commission has adopted the applicable federal pipeline safety regulations, including 49 CFR Part 192 that makes up the "minimum" federal safety standards applicable to natural gas pipelines. Additionally, the Commission's gas pipeline safety program undergoes an annual inspection by PHMSA personnel to ensure that the program is being operated in accordance with the federal/state cooperative agreement.

The Commission's gas pipeline safety program is carried out by the Gas Safety/Engineering Section (Gas Safety Section) of the Utility Operations Division's Energy Department. Staff are primarily involved in an on-going field inspection program consisting

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[3] "Interstate natural gas transmission pipelines" transport processed natural gas from processing plants in producing regions to areas with natural gas requirements. The pipeline network extends across the country, and is considered the "highway" of natural gas transmission. Natural gas is transported through interstate pipelines at high pressures from 200 to 1500 pounds per square inch (psi).

[4] According to information on the PHMSA website.

of comprehensive code compliance inspections of the jurisdictional operators. In addition, Staff conducts operation and maintenance compliance inspections, follow-up inspections, construction inspections and gas incident investigations. Staff also conducts safety-related consumer complaint investigations on an "as needed" basis. The Gas Safety Section consists of eight inspectors and a program manager. All nine of these positions are dedicated 100 percent to the gas pipeline safety program.

In Calendar Year 2009, Staff personnel conducted 75 individual comprehensive annual inspections which included all units of investor-owned utilities and municipal utilities. In addition to the comprehensive inspections, pipeline construction inspections and incident investigations were also conducted. Approximately 650 total Staff field days were spent on these inspections in Calendar Year 2009.

For Calendar Year 2010, Staff conducted approximately 74 comprehensive inspections, as well as follow-up inspections, construction inspections and special leak survey investigations. These inspections/investigations have resulted in Staff being out of the office over 630 days, with about one-third of those days being spent "in the field" physically inspecting pipeline facilities, conducting construction inspections, and verifying leak surveys and leak investigations.

The on-going comprehensive field inspection program is carried out according to an inspection priority list that is updated on an annual basis. The inspection "priorities" are primarily determined by the amount of time that has passed since the last inspection; however, consideration is given to the operator's competence and code compliance history, which could move the operator up on the priority list. The goal of the program is to conduct a comprehensive office and field inspection in each of the jurisdictional systems/inspection units every year.

Staff reports are written subsequent to each gas safety inspection, incident investigation and complaint investigation. Field notes, completed checklists and pertinent operator records are also maintained for these activities. In the event of a gas safety incident, Staff typically files a motion to establish a case for the investigation of the incident. The order opening case directs Staff to complete its investigation within 120 days of the date on which the case is established; however, depending on the circumstances, additional time may be needed. Two such cases were recently filed with the Commission.

1) File No. GS-2011-0245 – Staff filed a motion to establish a case for investigation of a reportable incident that occurred on January 8, 2011, in Pine Lawn, Missouri, an area served by Laclede Gas Company. Staff's initial investigation indicates that natural gas was released from a circumferential fracture in a 2-inch diameter steel main, migrated into the sanitary system and through the soil, and accumulated in the house at 3810 Council Grove Avenue. An explosion and flash fire resulted, causing extensive damage to the property.

2) File No. GS-2011-0248 – Staff filed a motion to establish a case for investigation of a reportable incident that occurred on February 2, 2011, in Kansas City, Missouri, an area served by Missouri Gas Energy. Staff's initial investigation indicates that natural gas was released from a fractured underground transmission line. A passer-by observed the gas, at a pressure of about 220 psig, blowing dirt from above the buried line. There was no fire or explosion.

Probable violations of Commission pipeline safety regulations discovered by Staff during its normal course of business are reported to the operators, who are then responsible for implementing appropriate corrective actions. Staff monitors operators to determine corrective actions are taken in a timely manner. If an operator does not take sufficient corrective action in a reasonable time period, Staff may file a formal complaint with the Commission to resolve the matter. Such complaints generally include a request for a Commission order directing the operator to comply with the rule(s) in question, as well as requesting authority to seek civil penalties from the operator in an appropriate circuit court.

Formal training of Staff is accomplished through attendance at all applicable PHMSA Office of Training and Qualification courses, as well as attendance at numerous other pipeline safety related seminars and/or short courses.

Commission-sponsored public safety education programs, coordinated by Staff, consist of state-wide press releases pertaining to consumer safety tips and radio messages promoting damage prevention efforts and referencing a gas safety website (mosafegas.com).

Staff participates in operator training by presenting seminars in cooperation with the Missouri Association of Natural Gas Operators (MANGO) and the Missouri Association of Municipal Utilities. PHMSA Office of Training and Qualification personnel attend the annual operator training seminars that are hosted by Staff and MANGO.

III. THE COMMISSION'S PIPELINE SAFETY REGULATIONS EXCEED NATIONAL STANDARDS

A. History of Revisions to Missouri's Pipeline Safety Regulations

Due to seven natural gas incidents that occurred in Missouri and Kansas in the winter of 1988/1989, which resulted in six fatalities, over a dozen injuries and at least seven structures being destroyed, the Commission took the initiative to develop significant revisions to the Missouri pipeline safety regulations. These new regulations made Missouri's rules more stringent than the applicable Federal regulations, and became effective on December 15, 1989. Missouri's regulations on gas safety standards can be found at 4 CSR 240-40.030. The significant changes included:

- Requiring operators to address specific activities in the utilities' operation and maintenance (O&M) plans, and requiring operator personnel to review the plans.
- Requiring the training of operation/maintenance/emergency response personnel, and requiring successful demonstration that all such personnel possess the knowledge and skills needed to perform the assigned tasks (including review of O&M plans).
- Requiring leak detection surveys (with an instrument) on a more frequent basis.
- Implementing systematic replacement programs and more frequent leak surveys pertaining to non-cathodically protected steel service lines and yard lines.
- Implementing systematic replacement programs (that must be approved by the Commission) for cast iron (CI) mains.
- Implementing systematic replacement and/or cathodic protection programs (that must be approved by the Commission) for non-cathodically protected steel mains.
- Prohibiting the installation of ***customer-owned*** service lines and yard lines.
- Requiring tests/checks of customer's facilities before initiation of service.
- Increasing the requirements for excavator notification to prevent damage to pipelines and for public education to enhance the recognition of and response to natural gas leaks.
- Requiring that all newly installed service regulators have full over-pressure protection.

These revisions to the Commission's gas pipeline safety regulations promoted increased safety on several fronts. First, programs were established to identify existing facilities that were considered as posing a potential safety risk (certain unprotected steel mains, certain cast iron mains, and non-cathodically protected steel service lines and steel yard lines) and to eliminate those facilities in those areas that presented the greatest potential for hazard first. Second, the preparation of a thorough, comprehensive operation and maintenance plan for each operator, coupled with required training of operations personnel, created a better trained workforce. Third, more frequent leak surveys were required to be conducted (with instruments) to enable operators to detect natural gas leaks before they become hazardous. This, in turn, can reduce the potential for problems/errors and enable operators to better identify potential problems on the system and correct them before hazardous situations occur.

Section 4 CSR 240-40.030(14) prescribes the procedure for the investigation and classification of gas leaks and for scheduling the repair of these leaks. Whenever the operator conducts work on a customer's premise for any type of customer gas service order or call, including all premise odor calls, tests of the subsurface atmosphere must be made.

Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. It shall require immediate corrective action which shall provide for public safety and protect property. Examples of class 1 leaks are: a gas fire, flash or explosion; broken gas facilities; or blowing gas in a populated area. In other words, class 1 leaks could occur from excavator damage to natural gas pipelines or when gas enters a building from company-owned piping.

Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. Examples of a Class 2 leak include natural gas leaking underground within five feet of a building or small amounts of natural gas detected in a sanitary sewer.

A follow-up leak investigation shall be conducted immediately after the repair of each Class 1 or Class 2 leak, and continue, as necessary, to determine the effectiveness of the repair and to assure all hazardous leaks in the affected area are corrected.

Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine actions. These leaks must be repaired within five years and be rechecked twice per calendar year, not to exceed six and one-half months, until repaired or until the facility is replaced. A Class 3 leak is any reading of fifty percent or less gas-in-air located between five and fifteen feet from a building Examples of a Class 3 leak include an underground natural gas leak that is located near the street.

Class 4 leak is a confined or localized leak which is completely non-hazardous. No further action is required. An example of a Class 4 leak would be a small amount of natural gas leaking on a shut-off valve in a valve box located near the street.

B. The Commission's Pipeline Replacement Programs

Investor-owned and municipally-owned natural gas systems have been required for over 20 years to accelerate leak surveys and prioritize replacement for piping that has the greatest potential for hazard (integrity issues)[5]. The operators must:

- Conduct annual leak surveys and replace unprotected (not protected from corrosion) steel service lines and yard lines.
- Replace cast iron pipelines in those areas that present the greatest potential for hazard in an expedited manner.
- Replace/cathodically protect unprotected steel transmission lines, feeder lines and mains in those areas that present the greatest potential for hazard in an expedited manner.

1. Results of the Commission's Pipeline Replacement Programs[6]

- Almost 1,100 miles of cast iron mains were eliminated, leaving approximately 1,200 miles to be replaced.
- Almost 1,100 miles of unprotected steel mains were eliminated (replaced or protected), leaving approximately 10 miles to be replaced.
- Almost 300,000 unprotected steel service lines and yard lines were eliminated, leaving approximately 33,150 lines to be replaced.

Pursuant to previous Commission orders, the remaining unprotected steel mains are required to be replaced by 2014 and the remaining unprotected steel service lines are required to be replaced by 2020. There is no requirement to eliminate cast iron mains; however, approximately 15 miles of cast iron main is being eliminated annually state-wide. Please see Staff Recommendation number 4 (Discussions on Aging Infrastructure) on page 26 for further information on addressing cast iron main replacement.

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[5] In 1989, problems on copper service lines had not been identified and there was not a regulation for replacement. Later, after incidents, copper service lines were required to be replaced, but were not part of replacement programs in the PSC Regulations. See section titled Additional Replacement Programs Required by the Commission for discussion on Laclede's copper service line replacement program.

[6] Information from DOT-PHMSA Annual Reports

C. Additional Replacement Programs Required by the Commission

In addition to the regulatory requirements for unprotected steel and cast iron noted above, the Commission's on-going inspection and investigation activities have identified other specific materials that could present integrity issues, so accelerated leak surveys and replacements were ordered by the Commission, including:

- Annual leak surveys and prioritized replacement of soft copper service lines (Laclede Gas Company…File Nos. GO-99-155 and GS-2008-0038). The program resulted in over 80,000 soft copper service lines being replaced. All known soft copper service lines will be replaced in 2011[7].
- Accelerated leak surveys over, and prioritized replacement of, identified older vintage plastic pipe (City Utilities of Springfield…File No. GS-2004-0257). Current on-going program requires annual leak surveys over identified piping and replacement of at least six miles of identified plastic main annually. This will result in indentified, older-vintage plastic pipe being eliminated in approximately 8 – 9 years.

IV. ANNUAL OPERATOR INSPECTION PROCEDURES

Staff conducts annual inspections on all units of investor-owned utilities and on municipal utilities. During these inspections, the records of natural gas operators are reviewed by Staff to verify compliance with pipeline safety regulations. The operators' facilities are also checked to verify information contained in the records. Near the end of each calendar year, Staff compiles a list of inspections to be conducted in the upcoming calendar year. During the actual inspection, the operator's records are reviewed and analyzed for compliance with the Commission's regulations. Staff follows an inspection checklist covering all phases of the operator's operation, maintenance, and emergency response functions, which includes review of proper installation of pipeline marker signs; steel welding qualifications; plastic joining qualifications; installation of excess flow valves; monitoring of corrosion control requirements; pressure testing of pipeline installations; liaison conducted with fire/police/other public officials; operator training requirements; natural gas educational/awareness programs implemented; odor intensity records; patrols of transmission pipelines, leak surveys, regulator station inspections; inspection of critical valves; immediate investigation and proper classification of any leak/odor call; proper monitoring of "active"

[7] NOTE: At this time there are 4 locations where records indicate a copper service line existed, but there are no buildings at these locations. Pursuant to the Commission's February 4, 2011 order in File No. GS-2008-0038, Laclede will conduct annual leak surveys in the general area of the locations until such time it determines the location and proper abandonment of the service lines.

leaks; timely repair of "active" leaks; accuracy of leak detection equipment; records indicating personnel were drug tested; and other records. To verify the accuracy and integrity of the operator's records, Staff also conducts a field investigation as part of the annual inspection. During the field investigation Staff selects facilities at random or based on Staff's decision that further on-site inspection was indicated. The facilities covered during the field inspection include regulator stations, essential valves, corrosion control levels, construction activities, location of line markers, meter-sets, odorant levels, and leak classifications.

V. THE COMMISSION'S ENHANCED INSPECTION PROGRAM

To further investigate and evaluate potential gas safety issues and the processes used to verify information from the operator, members of the Commission envisioned a proactive measure that would give Commission personnel the opportunity to have a more in-depth review of the companies' procedures and gauge the effectiveness of their safety programs. The Chairman[8] asked the operators to comply with a request to conduct special leak surveys over specified areas of several natural gas distribution companies' facilities.

The companies have established leak survey procedures and employees are required to follow operator training requirements. The special, comprehensive leak surveys were a proactive performance measure to verify the leak survey procedures, the ability of the employees performing the leak surveys, and the integrity of the distribution system.

The special leak surveys were coordinated as described below.

- The Chairman and Staff selected a random area of an operator's distribution system to be leak surveyed.
- The Chairman and Staff selected a date the leak survey was to be conducted.
- The Chairman notified the operator approximately five days before the date selected for the survey and instructed the operator on the specific details of the leak survey.
- The Pipeline Safety Regulations require leak detection instruments to be checked for accuracy according to the manufacturer's recommendations or at least once each calendar month. In addition to the required checks, Staff traveled to the operator's office on the day of the leak survey (prior to the start of the special leak survey) and observed the calibration/accuracy checks of leak survey instruments that were to be used during the leak surveys.

[8] For purposes of this report "Chairman" refers to Commissioner Robert M. Clayton, III, Chairman at the time of the report activities and preparation.

- Commission personnel then accompanied operator leak survey personnel and monitored the actual leak survey of all the company-owned natural gas facilities in the selected area.

The leak surveys over company-owned underground facilities also included checks of all of the above-ground piping comprising the meter-set and nearby accessible customer-owned fuel line piping going into the structure. Checks were also made at locations, such as checking the atmosphere in gas, electric, telephone and sewer manholes, telephone pedestals, gas and water valve boxes, water meter wells, cracks in pavement and sidewalks, the base of street signs and other locations that could provide a path for natural gas to migrate to the surface.

Special, comprehensive leak surveys were conducted over facilities of the following natural gas operators.

- AmerenUE (now Ameren Missouri) facilities in Center, MO
- Laclede Gas Company facilities in St. Peters/St. Charles, MO
- Missouri Gas Energy facilities in Kansas City, MO
- Empire District Gas Company facilities in Sedalia, MO
- Atmos Energy facilities in Hannibal, MO

A. <u>Summary of Special Comprehensive Leak Surveys</u>

1. <u>AmerenUE Natural Gas Facilities in Center, MO…July 14, 2010</u>

AmerenUE conducted a leak survey of its natural gas distribution system (mains and service lines) for the entire town of Center, MO and the high pressure feeder line serving the town from the take-point with the interstate transmission pipeline (Panhandle Eastern Pipe Line). The company used personnel and leak detection equipment from its Jefferson City, Wentzville, Columbia, Boonville, Moberly and Mexico offices to perform the leak survey.

Commission personnel monitoring the survey included the Chairman, the Chairman's Chief of Staff, the General Counsel, the Director of Utility Operations, the Manager of the Engineering and Management Services Department, and eight members of the Gas Safety Staff. The survey was also monitored by independent third parties.

Prior to traveling to Center, Staff went to the Jefferson City, Wentzville and Mexico AmerenUE offices to witness accuracy checks of the various leak detection instruments to be used for the survey.

Flame ionization (FI) detectors were checked using gas at a known concentration of 50 parts-per-million (ppm) methane. The Combustible Gas Indicators (CGIs) were checked using gas of known 100% methane concentration and at a second range using gas of known 2.5% methane concentration.

AmerenUE divided its distribution system into ten map grids and assigned a company employee to leak survey each grid of the distribution system and assigned two employees to the feeder line to perform the leak survey. Staff accompanied eight AmerenUE leak surveyors for the duration of the leak survey in the distribution system and Commission management personnel randomly spot checked the various surveys.

The leak survey was performed using FI detectors. Where the FI detectors indicated the possible presence of combustible gas coming from an underground source during the leak survey, AmerenUE used Combustible Gas Indicators (CGIs) to sample the subsurface atmosphere to confirm the presence of natural gas and to classify the leaks in accordance with Missouri Pipeline Safety Regulation, 4 CSR 240-40.030(14). For indications of a potential leak on above-ground piping, such as at customer meter-set piping, AmerenUE used the FI detectors or a soap solution to confirm the location of the leak.

During the leak survey over all of AmerenUE's natural gas facilities in Center, four very small natural gas thread leaks were found on company-owned, above-ground, meter-set piping and one on above-ground, customer-owned piping. All of these small outside leaks were repaired on July 14, 2010, by tightening fittings.

There were three locations where indications of a combustible gas were detectable with a CGI (two underground and one in a sewer manhole). Further investigations were made at the three locations. Those subsequent investigations (excavations at two locations and continued monitoring at the third location) found there were no longer indications of a combustible gas and therefore there was no natural gas leakage at these locations. Follow-up investigations found no indications of combustible gas at the locations.

2. <u>Laclede Gas Company Natural Gas Facilities in St. Peters/St. Charles, MO…October 7, 2010</u>

Staff traveled to Laclede Gas Company's North District Office in Berkeley to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the St. Peters/St. Charles area. Four different types of leak detection instruments were utilized during the inspection. The following list describes the instruments that were used. Laclede personnel and equipment from the North, South and Central Districts were used to conduct the special leak survey.

1) Flame ionization units. There were a total of 18 FI units tested with gas containing 50 parts per million of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm.
2) Mobile optical methane detector. Staff witnessed the start-up/calibration sequence to check the accuracy of the optical methane detectors (OMDs) on two mobile leak detection units. These units first display the "normal" occurring level of ppm of methane (which was approximately 10 ppm). Then the instrument is set 10 ppm above that level to give an alarm if methane at a level of 10 ppm above the normal background is detected.
3) Remote methane leak detector. Staff witnessed the start-up/calibration sequence to check the accuracy of the remote methane leak detector (RMLD) unit that was used to detect leakage over the transmission line crossing Interstate 70 and locations where heavy vegetation prevented walking over the line. The RMLD was set to detect a trace amount of natural gas in the form of a gas plume. The RMLD displayed single digit numbers when in the normal survey mode and would display double digit numbers if gas was detected. During the start-up/calibration sequence, the RMLD displayed double digit numbers indicating the detection of gas from the built-in test gas cell.
4) Combustible gas indicator. The fourth type of instrument that may be used in a leak survey is the CGI which is used to classify a leak when the instruments above detect a combustible gas. These instruments are set in a "cradle" and an accuracy/calibration test is run with gas having a known concentration. These tests are conducted monthly and were conducted at the end of September 2010 and/or the first of October 2010. After these monthly tests, all of the testing "cradles" were removed and Laclede was in the process of upgrading them. Laclede was not able to conduct accuracy/calibration checks on these instruments the day of the special leak survey because of the transition to the upgraded testing equipment that was not yet installed.

Following the accuracy checks, Laclede and Commission personnel met at a staging area located in the area selected for the leak survey. There were nine Gas Safety Staff, two Commissioners, the Utility Operations Division Director and numerous Laclede personnel. Commission personnel were "paired up" with Laclede leak survey personnel to: observe the operation of the mobile OMD leak survey; observe the use of the RMLD instrument; accompany Laclede personnel on the walking leak survey over the service lines; and accompany Laclede personnel on the walking leak survey over the mains and transmission pipeline that the mobile truck was not able to cover.

Laclede printed out maps of the area selected for the leak survey. Transmission lines and mains that could be surveyed by the mobile leak detection trucks were identified, as well as the transmission lines and mains that would require a walking survey or use of the RMLD. Service line cards were printed out for each address served by natural gas in the selected area. These service line cards had been "packaged" together in geographic areas and given to the Laclede personnel for the walking leak survey.

Laclede completed a leak survey and patrol over steel supply feeder (SF) mains. These mains, by definition, are treated as transmission lines in the Commission's gas safety program. The leak survey was performed using a combination of equipment. Transmission lines that are accessible from the roadway were leak surveyed using a truck mounted with OMD equipment. Portions of the mains that are not accessible from the roadway were leak surveyed by walking personnel using FI units. Any areas that cannot be driven or walked over were leak surveyed using a handheld RMLD. No leaks were found and no other items requiring follow-up or remedial action were reported.

Laclede completed the leak surveys over all the distribution mains in this area. Distribution mains that are accessible from the roadway were leak surveyed using a truck mounted with OMD equipment. Portions of the mains that are not accessible from the roadway were leak surveyed by walking personnel using FI units. Highway crossings were leak surveyed using the RMLD. No leaks were found during these leak surveys.

There were a total of 767 service lines that were leak surveyed in the leak survey area selected. These served a mixture of residential, commercial, and light industrial accounts. The service lines were either plastic or steel piping. The leak surveys were completed by walking over the service line locations using FI equipment. No underground leaks were found during the special leak survey.

The FI units detect methane at 50 PPM. Due to this sensitivity, a number of indications were found on above-ground meter-set piping. One small leak was found on the customer's above-ground fuel line and the valve on the fuel line was closed and a yellow caution tag was left on the customer's door. There were over 40 locations on company-owned, meter-set piping where small, above-ground leaks were found. These indications were small localized or confined leaks, were considered non-hazardous and were classified as

Class 4 Leaks[9] for which no remedial action is required. A total of nine Class 4 Leaks were at locations such as pressure regulators or public locations where the leak is likely to be reported as a nuisance. In these cases, Laclede's practice is to request service technicians be scheduled to perform remedial action. All other Class 4 Leaks found on company-owned piping during this special leak survey were repaired by the end of the day on October 8, 2010.

3. Missouri Gas Energy in Kansas City, MO…October 28, 2010

On Thursday, October 28, 2010, four Staff traveled to MGE's Central District Office in Kansas City to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Kansas City area. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units (FI). There were a total of seven FI units tested. One FI unit was used in a mobile leak survey truck for surveying over mains and one FI unit was used by an MGE crew to follow-up on any leak detected by the mobile FI unit. The remaining five units were used by the walking surveyors over service lines. The test was conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey. All but one of the instruments alarmed and displayed a full scale reading during the test. The failed unit was replaced with a unit that tested accurately with 50 ppm test gas.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the combustible gas indicator (CGI) that is used to classify a leak when the instrument above indicates combustible gas is detected. There were a total of seven CGIs tested. One CGI was kept with the mobile leak survey truck and one CGI was used by an MGE crew to follow-up on any leak detected by the mobile truck. The remaining five CGIs were kept with the walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines. These instruments were checked for accuracy with known concentrations of test gas. The Lower Explosive Limit (LEL) scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are normally conducted monthly and were conducted again prior to the leak survey. All of the CGI units tested accurately with the known concentrations of test gas.

Following the accuracy checks noted above, numerous MGE personnel and the four Staff members proceeded to a staging area located in the area selected for the leak survey. At

[9] Class 4 leak is a confined or localized leak which is completely non-hazardous. No further action is required.

the staging area, Staff was joined by the Utility Operations Division Director and the Chairman.

Four MGE employees conducted the walking leak survey in the area specified, one MGE employee drove the mobile leak survey truck, one MGE employee trailed the mobile truck conducting leak surveys over mains the mobile truck could not reach, and a MGE foreman participated to oversee the work performed on the special leak survey.

Staff members were "paired up" with MGE leak survey personnel to: observe the operation of the mobile leak survey truck, accompany MGE personnel on the walking survey over the service lines and accompany MGE personnel on the walking survey over the mains that the mobile truck was not able to cover. MGE management personnel accompanied MGE leak survey personnel and Staff on the special leak survey. The Chairman also observed the special leak survey process.

Prior to the special leak survey, MGE personnel printed Service Line Survey sheets, copied information for any active Class 3 Leaks[10] and sent the information with the mobile truck, and printed maps for each of the survey groups and pressure system maps.

In the area selected there was cast iron main, protected bare steel main, protected coated steel main, polyethylene mains, and approximately 305 service lines (protected steel and polyethylene). There were four active underground Class 3 Leaks that were checked and detected in the area during the special leak survey. One additional underground Class 3 Leak was found and classified during the survey. In addition, one above-ground Class 4 Leak was found on meter-set piping.

MGE indicated that the five Class 3 underground leaks (four active leaks and one new leak) will have follow-up leak investigations performed, and repairs completed, as required by 4 CSR 240-40.030(14)(C). The one above-ground leak on meter-set piping was repaired the day of the survey by rebuilding the meter-set piping.

[10] Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine actions. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6½) months, until repaired or until the facility is replaced.

4. Empire District Gas Company Natural Gas Facilities in Sedalia, MO…November 11, 2010

Six Staff members traveled to the Empire District Gas office in Sedalia, Missouri to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Sedalia area. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units (FI). There were a total of three FI units tested. All three units were used by the walking surveyors over service lines and mains. The test was conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the CGI that is used to classify a leak when the instrument above indicates combustible gas is detected. There were a total of three CGI's tested. One unit was unable to be calibrated correctly on the 100 percent scale, and it was not used for the survey. The other two were used with walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines or mains. These instruments were checked for accuracy with known concentrations of test gas. The LEL scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are normally conducted monthly and were conducted again prior to the leak survey. All of the CGI units that were used during the survey tested accurately with the known concentrations of test gas.

Two Staff members, including the Director of Utility Operations, accompanied each of the Empire leak survey personnel conducting the walking leak survey. During the special leak survey, three Empire employees accompanied by Staff leak surveyed a mostly residential area of Empire's gas distribution system in Sedalia. The survey took approximately four hours and covered over two miles of main and 153 service lines. No underground leaks were found during this survey. Small thread leaks were found on above-ground meter-set piping at two individual residences and two commercial locations. The simple repairs required at these meter-sets were completed November 15, 2010.

5. Atmos Energy Natural Gas Facilities in Hannibal, MO…November 22, 2010

Two Staff members and the Utility Operations Division Director traveled to the Atmos Energy office in Hannibal, Missouri to witness the accuracy checks of leak detection instruments to be used during the special leak survey in the Hannibal area. Staff members were joined at the Atmos office by the Commission Chairman. Two different types of leak detection instruments were utilized during the inspection.

1) Flame ionization units. There were a total of two FI units tested. The two units were used by the walking surveyors over service lines and mains. The tests were conducted by placing the probe of the instrument in a stream of gas containing 50 ppm of methane. The instrument was set to sound an alarm and display a full scale reading at 50 ppm. These instruments are normally tested monthly and were tested again prior to the leak survey.
2) Combustible gas indicator. The second type of instrument that may be used in a leak survey is the CGI that is used to classify a leak when the instrument above indicates combustible gas is detected. The two units were used with walking surveyors to follow-up on any leaks they may have detected with their FI unit over the service lines or mains. The LEL scale of the instruments was tested with a known concentration of 2.5 percent methane and the 100 percent scale of the instruments was tested with a known concentration of 100 percent methane. These tests are conducted monthly.

Following the accuracy checks, Staff and the Utility Operations Division Director were "paired up" with Atmos leak survey personnel to accompany them on the walking survey over the mains and service lines in the selected leak survey area. Atmos management personnel and the Chairman also participated in the leak survey. Atmos personnel had previously printed maps of the area in Hannibal that was selected for the special leak survey and divided the work between two crews.

No underground leaks were found during the special leak survey. There were five small above-ground leaks found on company-owned meter-set piping. Atmos personnel were able to tighten fittings and fix one of the leaks on company-owned piping during the leak survey. Atmos indicates that the four remaining above-ground leaks that were found have also been repaired. The special leak survey covered approximately 3,600 feet of main and 110 service lines. All the mains and service lines in the area surveyed were constructed of polyethylene pipe.

B. Conclusions as a Result of the Commission's Enhanced Inspection Program

During the special leak surveys over the AmerenUE, Laclede, MGE, Empire and Atmos facilities, there were minor above-ground leaks and one non-hazardous underground leak that had not been previously classified by the utility. In the areas surveyed, Staff found nothing that would not have been expected under normal operations. Although facilities appeared satisfactory at the time of inspection, that is not an indication that leaks will not occur in the future or in other locations. Therefore, Staff will incorporate accompanying leak survey personnel on random leak surveys into its annual inspection process.

VI. ADDITIONAL PIPELINE SAFETY REGULATIONS AND EFFORTS

The U. S. DOT-PHMSA has issued Federal Pipeline Safety integrity management regulations to address the integrity of transmission and distribution pipelines. Those programs are described more fully below.

A. Gas Transmission Pipeline Integrity Management Program (Gas IM)11

Transmission pipelines are defined as pipelines that operate at pressures that are equal to or greater than 20 percent of the pressure that would cause the pipeline to yield.

The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas (HCAs) within the United States. HCAs include certain populated and occupied areas such as neighborhoods, hospitals and shopping areas in close proximity to gas transmission pipelines. The Gas IM regulations and the Commission have placed a high priority on the integrity of gas transmission pipelines in HCAs since a leak or failure in these areas has the potential of impacting a large number of individuals, structures and resources.

The objective of the Gas IM Regulation is to improve pipeline safety through:

- Accelerating the integrity assessment of pipelines in High Consequence Areas;
- Improving integrity management systems within companies;
- Improving the government's role in reviewing the adequacy of integrity programs and plans; and
- Providing increased public assurance in pipeline safety.

Pursuant to the Gas IM Regulation, operators must:

- Provide enhanced protection for defined High Consequence Areas.
- Develop a written Integrity Management Plan for its Integrity Management Program.
- Implement an Integrity Management Program that includes, among other things:
    - Identification of all high consequence areas

[11] Gas Transmission Pipeline Integrity Management Rule (49 CFR Part 192, Subpart O) is incorporated by reference in 4 CSR 240-40.030(16)

- Baseline Assessment Plan (50% was to be completed by 2007, remaining assessment must be completed by December 17, 2012).
- Identification of threats and action taken to address threats.
- Provisions for remediating conditions found during integrity assessments.
- A process for continual evaluation, assessment and preventive measures.

Gas transmission pipeline operators are required to submit semi-annual performance measure reports on their Integrity Management programs, and annual reports on their pipeline infrastructure. PHMSA uses these reports – due at the end of February/August and March 15 respectively – to monitor industry progress in complying with requirements of the Gas IM Rule, to prioritize regulatory inspections, and to respond to inquiries about PHMSA's oversight program. Staff reviews these reports.

These performance measure reports provide information pertaining to operators' Integrity Management Programs, including the amounts of miles inspected and assessed, the operator's repair activities addressing time-sensitive conditions, and the numbers and types of incidents, leaks, and failures occurring in HCA segments of their pipelines.

According to the Calendar Year 2009 report:

- There are 693 miles of natural gas transmission pipelines in Missouri.
- There were 3 leaks on Missouri transmission pipelines in Calendar Year 2009.
- Approximately 80 percent of the required Gas IM assessments have been completed, so operator assessments are ahead of schedule.

B. Distribution Integrity Management Program (DIMP)

PHMSA promulgated a DIMP rule[12] to address lines not included in the Gas IM.

The Distribution Integrity regulations aim to assure pipeline integrity and improve the safety record for the transportation of energy products. Significant differences in system design and local conditions affecting distribution pipeline safety preclude applying the same tools and management practices as were used for transmission pipeline systems. Following a joint effort involving PHMSA, the gas distribution industry, representatives of the public, and the National Association of Pipeline Safety Representatives to explore potential approaches, PHMSA took a slightly different approach for distribution integrity management.

[12] This final rule amended the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management programs. The final rule was effective February 2, 2010. (See: 74 FR 63906)

Operators are required to identify and implement measures to reduce risk of failure of their gas distribution pipeline. They must measure performance, monitor results, and evaluate effectiveness including the following metrics:

1. Number of hazardous leaks either eliminated or repaired categorized by cause
2. Number of excavation damages
3. Number of excavation tickets (based on One-Call tickets)
4. Total number of leaks eliminated or repaired, categorized by cause.
5. Number of hazardous leaks eliminated or repaired categorized by material
6. Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's program in controlling each identified threat.

The first four metrics must be reported by the operator to the state pipeline safety authority if a state exercises jurisdiction over the pipeline and to PHMSA.

The regulation requires operators, such as natural gas distribution companies, to develop and implement a written distribution integrity management program plan by August 2, 2011. The DIMP set out the following requirements:

- The operators must demonstrate knowledge of the applicable gas distribution system.
- The operators must identify threats to each gas distribution pipeline.
- The operators must evaluate and rank risks associated with distribution pipelines.
- The operators must identify and implement measures to address risks.
- The operators must measure performance, monitor results, and evaluate effectiveness.
- The operators must perform periodic evaluations of the plan and make improvements as needed.
- The operators must report results on an annual basis to the Commission and the DOT-PHMSA.

Staff will evaluate the DIMP plans, monitor them for reasonableness and accuracy, review operations and applicability during inspections, and make recommendations for changes in areas that need improvement.

C. The Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act

In 2006, Congress passed the PIPES Act[13], which prescribed nine program elements (9 Elements) that reflect processes and attributes characteristic of comprehensive and effective damage prevention programs based on actions taken in those states with effective damage prevention programs that have successfully reduced the number of damages to underground facilities. The PIPES Act noted that an effective damage prevention program includes:

1. Participation by operators, excavators and other stakeholders in the development and implementation of effective communications from receipt of an excavation notification to successful completion of the excavation.
2. A process for fostering and ensuring the support and partnership of all stakeholders.
3. A process for fostering and ensuring active participation by all stakeholders in public education efforts.
4. A process for reviewing the adequacy of a pipeline operator's internal performance measures and quality assurance programs regarding persons performing locating services.
5. Participation by all stakeholders in the development and implementation of effective employee training.
6. A process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.
7. Enforcement of state damage prevention laws and regulations and the use of civil penalties for violations.
8. A process for fostering and promoting the use of, by all stakeholders, improving technologies that may enhance communications, underground pipeline locating capability and gathering and analyzing information about the accuracy and effectiveness of locating programs.
9. A process for review and analysis of the effectiveness of each program element, including a means for implementing improvements.

In addition to the above 9 Elements, a key aspect of a successful damage prevention program is the collection and analysis of data related to the number and causes of excavation-related damages to underground facilities, with the analysis of the data being used as the basis for enhancements to the overall program, particularly in the areas of educational and enforcement efforts related to the program.

[13] Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006. Public Law 109-469. 109th Congress. 49 USC 60101. December 29, 2006.

1. <u>Commission Damage Prevention Efforts</u>

In September 2009, Staff presented the Commission with a whitepaper[14] discussing the PIPES Act and discussing changes that might be needed to improve Missouri's damage prevention program. The paper summarized recommended actions, including:

- Place a greater emphasis on damage prevention efforts within Staff for all utilities regulated by the Commission.
- Plan, schedule and conduct stakeholder roundtables/workshops.
- Require reporting of all third-party excavation damages for all underground facility and the creation of a database to store/analyze the data.
- Draft legislation to revise Chapter 319 based primarily on the concepts contained in the 9 Elements, as deemed appropriate and necessary.

As a result of the PIPES Act, and the Commission's concern about the number of excavation damages to natural gas pipelines and other jurisdictional underground facilities[15], the Commission authorized Staff to pursue its recommendations.

Staff has been working with interested stakeholders on draft, proposed legislation to modify the Missouri Damage Prevention Act consistent with the PIPES Act. In October 2009, the Commission established File No. GW-2010-0120 to seek stakeholder input on the draft legislation. This working docket contains background information, drafts of proposed legislation to revise Chapter 319, stakeholder comments in response to the draft legislation and information about roundtables that were held to further discuss various drafts and

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[14] See: Motion to Open Repository Docket, Distribution Packet re Proposed Changes to Chapter 319. Docket No. GW-2010-0120. Commission's Electronic Filing and Information System (EFIS) at http://pscprodweb/mpsc/. October 14, 2009.

[15] Each year numerous underground utility facilities are damaged by excavations ranging from homeowner landscaping projects to highway/road construction projects. Damages can cause loss of utility service, can cause significant damage, or can cause injury or death. Damages to underground facilities are considered very serious. Statistics for damages to underground facilities in Missouri include:

- Average number of third-party excavation damages reported for PSC regulated natural gas pipeline systems:
  - Calendar Year 2006 through Calendar Year 2010 – 2,498 annually (about 210 damages/month)
- Average number of third-party excavation damages reported for all PSC regulated underground facility owners (gas, electric, water/sewer and telecommunications):
  - Calendar Year 2006 through Calendar Year 2008 – 11,882 annually (about 1,000 damages/month)

proposals. Roundtables were conducted on October 21, 2009, March 9, 2010, and December 6, 2010, to solicit stakeholder input and were webcast to reach as broad an audience as possible. Consensus was reached on some areas of the proposed legislation, but there were other areas where consensus was not possible. Specific recommendations related to the legislation are discussed below.

2. Grants to Assist Missouri's Damage Prevention Efforts

For the last three years, the Commission has been awarded One Call Grants to enhance public education/awareness about excavation damage prevention in general, and specifically the "Call Before You Dig" message. The education/awareness effort is a radio campaign with excavation safety messages broadcast on radio stations across the state. These radio messages educate the general public and excavators about excavation damage prevention requirements and the importance of calling 1-800-DIG-RITE or "811" before beginning any excavation project. In conjunction with this radio education/awareness project, www.mosafegas.com was developed to provide a resource where consumers can find more information about gas safety and excavation damage prevention.

In September 2010, the Commission applied for a State Damage Prevention Grant to fund a Damage Prevention & Excavation Safety Summit. The plan for the summit is to:

- Provide more than 50 hours of educational instruction designed to familiarize attendees with legally required activities, industry standards and best practices, and pertinent theories to proactively avoid damages.
- Raise awareness of the current state of utility damages and encourage summit participants to implement practices to reduce damages and to educate colleagues, customers, and the general public on the importance of damage avoidance.
- Provide a mechanism for the review and input of the proposed revisions to Missouri Statutes regarding underground utility safety.

VII. STAFF RECOMMENDATIONS TO IMPROVE THE GAS SAFETY PROGRAM IN MISSOURI

As highlighted throughout this Report, the Commission has made several changes to its Gas Safety Program to improve the integrity and safety of gas pipelines in Missouri. For instance, the Commission has directed LDCs to replace various lines and mains and has increased the requirements contained in its pipeline safety rules. However, in an effort to remain proactive, the Commission periodically reviews its current efforts and considers changes to its Gas Safety Program to ensure continued improvement. As part of that effort, the Gas Safety Staff makes the following recommendations for enhancements to the Gas Safety Program.

A. Introduce proposed excavation damage prevention legislation that will make revisions to Chapter 319.

The proposed legislation would support damage prevention by developing a program that incorporates the nine elements of excavation damage prevention outlined in the PIPES Act of 2006. To enhance Missouri's program, the proposed legislation would include provisions related to enforcement efforts and Commission investigation of possible violation by gas corporations, gas pipelines and municipal gas systems subject to the Commission's safety jurisdiction and adds provisions authorizing underground facility owners, excavators and the notification center to submit information to the Commission supporting the investigations. The legislation would also include reporting requirements and would establish requirements pertaining to underground facility locating performance measures and quality assurance programs. A copy of Staff's most recent draft revisions to Chapter 319 are attached as Attachment 1.

B. Promulgate rulemakings to enhance Missouri's gas safety program

a. Commission Adoption of Amendments to the Federal Pipeline Safety Regulations

- Promulgate a rulemaking that will adopt the Federal Annual/Incident Reporting requirements, Distribution Integrity Management Regulation, Control Room Management requirements, and several other amendments to the Federal Pipeline Safety Regulations into the Commission's Pipeline Safety Regulations.

b. Revisions to the Commission's Pipeline Safety Regulations

- Require quarterly reporting to the MoPSC Gas Safety Staff of locations were multiple publicly-reported leak/odor calls have originated from the same location/address.

- Require natural gas operators to report when they are aware that a person required medical attention as a result of the release of natural gas from operator facilities.
- Reduce the time period to repair Class 3 leaks.

C. If damage prevention legislation is not pursued, promulgate rules applicable to Commission-jurisdictional underground facilities owners

a. Require "real-time" reporting of each known "damage event" to a Damage Information Reporting Tool (DIRT) database, a virtual, private database to be established by the Commission with the Common Ground Alliance (Missouri Virtual Private DIRT);

b. Require quarterly reporting of the number and type of excavation notices received from the notification center to the DIRT database established with the Common Ground Alliance (Missouri Virtual Private DIRT);

c. Require the implementation of performance measures applicable to all persons that perform underground facility marking for facility owners;

d. Require the implementation of quality assurance programs to ensure the facility marking performance measures are being met.

D. Discussions on Aging Infrastructure

a. Review of the integrity of older cast iron and steel natural gas pipeline facilities needs to be completed with the possible goal of initiating specific long-term replacement programs to eliminate significant mileage each year. Currently, there are cast iron natural gas pipelines in service in Missouri that were installed well over 100 years ago. Two Missouri natural gas operators have a combined total of over 1,200 miles of cast iron in their distribution systems. The recommendation is for Staff to have meetings with the utilities that have these facilities and discuss the issue of systematic replacement of the aging infrastructure and the impact on rates. There are integrity issues, maintenance issues, service reliability issues and rate issues involved. The issues are related to safety, but there is also a policy decision that needs to be evaluated to determine the implications of continuing to have cast iron piping in distribution systems 30 years or 40 years from now. There should also be a discussion as to how much it will cost to initiate replacement programs for a specified number of years, and the rate implications of such programs. If the current annual replacement rate for cast iron pipelines (the average over the last three calendar years has been approximately 15 miles annually) continues, it would take over 80 years to replace the cast iron pipelines in Missouri, which could result in cast iron piping that is over 200 years old carrying natural gas. Also, older steel pipelines have been involved in the two recent incidents in Missouri. The age of the steel pipeline, by itself, may not be a determining factor. The age, as well as other integrity factors would need to be included in the review.

E. Create an educational brochure or consumer bill of rights for landowners with property near high consequence area[16] pipelines.

VIII. CONCLUSION

The Commission believes that safety is its highest priority in protecting citizens from hazardous conditions. Major constructive changes in Missouri pipeline safety occurred in the 1990s, which have dramatically improved safety conditions. Additionally, state statutes have been amended modestly increasing the Commission's penalty authority for violations. Because of this work in the past, Missouri is a much safer place. Recent surprise leak survey inspections in the past year have confirmed the integrity of Missouri natural gas transmission and distribution systems.

However, no regulator can rest on past efforts and the Commission believes more can be done to continue improving our natural gas delivery system. Many improvements require increased investment and deeper scrutiny. The Commission will consider and potentially pursue staff's recommendations and closely monitor required utility filings. While the Commission believes Missouri customers are safe from natural gas incidents, it will pursue all cost effective measures by utilities to help make systems even safer. The Commission thanks its staff for its efforts and looks forward to the work that lies ahead.

[16] For definition of high consequence area, see discussion at VI.A, page 26