The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which almost 92 percent - more than 65 million customers - receive their gas from AGA members. Today, natural gas meets almost one-fourth of the United States’ energy needs.

In late June, the Pipeline and Hazardous Material Safety Administration (PHMSA) issued a flow chart reflecting its draft Integrity Verification Process (IVP) for gas transmission pipelines. AGA appreciates the conference call held by PHMSA staff in the weeks following publication to explain portions of the flow chart. In discussions with AGA, PHMSA staff acknowledged the flow chart is incomplete and was published with no supporting technical documents. Based upon preliminary review, AGA feels compelled to submit comments with the understanding that there will be an opportunity for PHMSA, the states, and other stakeholders to elaborate at and beyond the August 7, 2013 workshop. It is believed that the submission of these comments will help facilitate the workshop. AGA has the following observations and suggestions.

1. AGA’s member companies are deeply committed to pipeline safety and, more specifically, following the Congressional mandates included in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (hereafter called the Pipeline Safety Act). The Pipeline Safety Act requires operators to perform a one-time verification of MAOP records for transmission pipelines and to conduct pressure testing (or its
equivalent) on transmission pipelines in high consequence areas (HCAs) that have not been tested. AGA believes that the PHMSA draft IVP, if codified, would be in direct conflict with certain mandates in the Pipeline Safety Act.

2. The primary process path of the draft IVP appears to require cutting thousands of holes in gas transmission pipelines operating under pressure to collect coupons for material testing. This activity has risks to both the operator’s personnel and the public and should only be performed when there is a clearly defined and understood benefit.

3. The PHMSA draft IVP mixes the testing requirements of Subpart J Test Requirements and Subpart L Operations, with an expansion of the Integrity Management Program requirements in Subpart O Gas Transmission Pipeline Integrity Management. This creates a complex process that is operationally impractical. It is critical to keep these concepts separate.

AGA commends PHMSA for its efforts in enhancing pipeline safety. However, the complexity of the PHMSA draft IVP, and the reliance on unproven operating practices, has AGA concerned about the safety implications associated with the process.

To move the regulatory process forward in an expedited manner and implement the Congressional mandates in the Pipeline Safety Act, AGA has submitted herein suggested amended regulatory language to 49 CFR § 192.619 Maximum allowable operating pressure: Steel or plastic pipelines that provides for pressure testing, replacement, In-Line Inspection (ILI) testing, pressure reduction or abandonment of the nation’s gas transmission pipelines. The amendments to the regulation are straight forward, safe and effective. See Exhibit I. The proposed amendment leverages industry practices, PHMSA regulations and proven technology for validating the Maximum Allowable Operating Pressures (MAOP) of natural gas transmission pipelines. The language is written to follow the legislative mandates in the Pipeline Safety Act. AGA requests that PHMSA consider the language.

Detailed Comments
II. Amending 49 CFR § 192.619
There are four primary criteria used by pipeline operators in establishing MAOP of a natural gas transmission pipeline under the existing code: Design Pressure, Pressure Test, Historic
Operating Pressure and the Maximum Safe Pressure. The amended language that AGA is proposing builds upon the existing system and forces operators to comply with all of the additional testing requirements mandated in the Pipeline Safety Act section 23(d). The amended language allows the existing regulations for distribution pipelines which are also regulated by 49 CFR § 192.619 to remain unchanged.

The amended regulation would require a testing program that is comprehensive and takes into account the uniqueness of each transmission pipeline system. AGA recognizes that the proposed regulation will be very costly for intrastate pipeline operators, and that it will be necessary for the companies to submit implementation plans to its jurisdictional authority.

PHMSA’s enabling statute establishes federal oversight of state pipeline safety programs. Therefore, PHMSA has the ability to implement oversight for the plans submitted to state regulatory agencies.

III. The legal Implications of the draft PHMSA IVP

PHMSA stated that the draft IVP “will help address several mandates set forth in Section 23, Maximum Allowable Operating Pressure, of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011”. AGA believes that implementing the draft IVP would be in conflict with several provisions of the Pipeline Safety Act. The law regarding agencies implementing federal statutes is settled.

*Chevron v. NRDC* 467 U.S. 837 (1984), stated that, "When a court reviews an agency's construction of the statute which it administers, it is confronted with two questions." 467 U. S., at 842. First, applying the ordinary tools of statutory construction, the court must determine "whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." Id., at 842-843. But "if the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute." Id., at 843.

*Chevron* is rooted in a background presumption of congressional intent: namely, "that Congress, when it left ambiguity in a statute" administered by an agency, "understood that the ambiguity would be resolved, first and foremost, by the agency, and desired the agency (rather than the courts) to possess whatever degree of discretion the ambiguity allows." *Smiley v. Citibank (South Dakota), N. A.*, 517 U. S. 735, 740-741 (1996). *Chevron* thus provides a stable background rule against which Congress can legislate: Statutory ambiguities will be resolved, within the bounds of reasonable interpretation, not by the courts but by the administering agency. See *Iowa Utilities Bd.*, 525 U. S., at 397.

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Congress knows to speak in plain terms when it wishes to circumscribe, and in capacious terms when it wishes to enlarge, agency discretion.²

There is nothing ambiguous in the Pipeline Safety Act of 2011. Congress was not circumscribed and did not speak in ambiguous terms. Congress referenced portions of 49 CFR 192 to ensure that their intent was clear. The relevant legislation stated, in part,

SEC. 23. MAXIMUM ALLOWABLE OPERATING PRESSURE.

“(d) TESTING REGULATIONS.—
“(1) IN GENERAL.—Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.
“(2) CONSIDERATIONS.—In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum—
“(A) pressure testing; and
“(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.
“(3) COMPLETION OF TESTING.—The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions.
“(e) HIGH-CONSEQUENCE AREA DEFINED.—In this section, the term ‘high-consequence area’ means an area described in section 60109(a).”.

Congress expressly stated that it wanted PHMSA to issue regulations for testing untested pipe by July 2013. Congress expressly stated that pressure testing or other equivalent methods, including ILI, could be used. Congress wanted the regulation to give priority to high consequence areas (HCAs). Congress also wanted to give priority to high stress pipelines above 30% Specified Minimum Yield Strength (SMYS).

IV. AGA Study on Pressure Testing and Replacement

AGA retained EN Engineering to perform an independent study with the objective of providing an analysis of the impacts increased testing requirements may have on AGA member companies, as well as the entire intrastate pipeline industry. AGA is submitting the Evaluation of MAOP Testing for Transmission Pipelines by EN Engineering concurrent with these comments. As part of this study, the options of testing, replacement and lowering operating pressure were reviewed. Review of nominal pipe diameters and class location of the data set

show a strong correlation between AGA companies that submitted the data and all pipelines classified as intrastate pipelines. Interstate pipeline companies have different operating and size characteristics and are excluded from any analysis in this study.

The study concludes that,

- For AGA companies, the estimated cost to complete MAOP testing in Class 3, 4 and HCA locations is $11.9 billion. If regulations mandate testing in all class locations, this cost increases to $24.7 billion.
- Extrapolation to all intrastate pipelines increases estimated costs to $23.0 billion for testing in class 3, 4 and HCA locations, and $49.6 billion for all class locations.
- Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. A carte blanche application, across all operators, of a standardized method for MAOP validation, cannot feasibly be implemented. Operators will need to work individually with each of their Commissions to determine the feasible plan for each affected pipeline, and engineering prioritization studies.\(^3\)

In order to gauge the potential impacts to the industry, fifty-six (56) AGA member companies (52,444 transmission miles) provided advance data on their anticipated reporting for the calendar year 2012 PHMSA Transmission Annual Report. This report included information pertaining to:

- Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
- Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
- Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

AGA members submitted the data in February 2013, and this data closely correlates to the data these companies submitted to PHMSA in June 2013.

**V. The Technical Implication of the PHMSA Draft IVP**

AGA will submit detailed comments after the PHMSA workshop on August 7\(^{th}\) to address the technical implications raised by PHMSA’s draft IVP. A few concerns about the technical practicality of the process are highlighted below.

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\(^3\) *Evaluation of MAOP Testing for Transmission Pipelines* by EN Engineering, June 20, 2013,
The first section of PHMSA’s draft IVP is labeled “Screen for Applicability Grandfather Clause and MAOP Records.” Steps one through five appear to mimic the MAOP method selection process used in 49 CFR §192.619. However, the draft IVP treats the MAOP methodologies completely different than PHMSA, state regulators and operators have applied the regulation for more than forty years. The PHMSA draft IVP treats pre-1970 and post-1970 records in an identical manner, while existing regulations have different record keeping requirements for pre- and post-1970 pipe. PHMSA’s draft IVP forces operators to have complete records in all MAOP method selection categories in §192.619(a)(1-4) and §192.619(c). Existing regulations require operators to compare the available information in the MAOP categories and used the appropriate information. A single record, such as a pressure test, is adequate for MAOP verification. Additionally, requiring complete records in all MAOP categories is inconsistent with existing regulation, operator practices, and PHMSA’s transmission and gathering annual report form Part Q that was created in 2012.

The section of the draft IVP that essentially all pipelines will be directed to follow on the decision tree is labeled “Material Documentation Process.” Historically, the overwhelming preference to determine the strength of pipe is via a pressure test. Operators use the pressure test procedures in 49 CFR 192 Subpart J for newly installed pipelines. The historic operating pressure to establish MAOP under 49 CFR §192.619(a)3 has also been used, and its use is only permitted when the historical pressure has demonstrated to be lower or equal to the MAOP calculated from design records or a pressure test. Testing the coupon tensile strength will provide information on the steel of the normal 20 foot pipe joint, but this method of material testing reveals nothing about girth welds, long seam welds, couplings, or the adjacent joint. This test method is already available in 49 CFR §192.107. Tensile strength testing per section II-D of Appendix B was considered as a least favored option, but the PHMSA draft IVP seems to treat it as a primary step in MAOP establishment. Operator personnel are trained to perform hot taps on pressurized pipelines. However, it is an operation that increases the potential for personal injury and should not be performed unnecessarily.

V. Conclusion

AGA commends PHMSA’s continuing commitment to pipeline safety and it appreciates the opportunity to comment on the PHMSA draft IVP. Safety is AGA’s number one priority and it welcomes honest, forthright public discussion to enhance safety. AGA has serious concerns
with the PHMSA draft IVP. There are legal and technical problems that make the draft IVP process overly complex and in some cases extremely difficult, if not impossible, to implement without compromising safety, reliability and efficiency.

To move the regulatory process forward, AGA has offered regulatory language that implements Congressional mandates, is consistent with PHMSA regulations, current industry practices, and uses proven technology. Some operators are already implementing the mandates in section 23(d) of the Pipeline Safety Act. These operators would suffer unnecessary and irreparable harm if PHMSA was to codify its IVP process, as proposed. AGA requests a critical analysis of the regulatory language that it has proposed to implement the testing provisions of the Pipeline Safety Act. Finally, AGA offers the EN Engineering report for the cost–benefit analysis that must be performed for rulemaking.

AGA is very open to working with PHMSA, its state partners, public representatives and other stakeholders on a way to meet the Congressional mandates and PHMSA’s goals. Our purpose is the same...the safe, reliable and efficient delivery of natural gas.

If you need additional information please feel free to contact me.

Respectfully submitted,

Date:

By:  [Signature]

Christina Sames

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AGA Proposed Regulatory Language: 192.619 (Note – Changes of note are in paragraph e)

§192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?
(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

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

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

(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

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

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

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

<table>
<thead>
<tr>
<th>Class location</th>
<th>Installed before Nov. 12, 1970</th>
<th>Installed after Nov. 11, 1970</th>
<th>Covered under §192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td>5 years preceding applicable date in second column.</td>
</tr>
<tr>
<td>—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

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

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

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

(e) Transmission pipelines operating greater than 30% SMYS in HCAs:

   (1) For transmission pipelines located in HCAs with a MAOP that produces a hoop stress of greater than or equal to 30% of SMYS and that have not been previously tested, the pipeline must be subjected to one of the following tests;

      (i) a pressure test consistent with the requirements of section a(2),

      (ii) an in-line inspection,

      (iii) a reduction in pipeline MAOP by 20%, or

      (iv) a procedure that has been approved by the Administrator.

   (2) the operator shall within 12 months of this final rule, submit a plan (not to exceed xxx years in duration) to the authorities having safety and ratemaking jurisdiction to test the segment according to one of the methods in (e)(1) above. Post construction pressure tests will be conducted in accordance with Part 192, Subpart J.

Note: The language maintains the existing grandfathering for all distribution pipe and transmission pipe below 30% SMYS. It gives four options for pipe above 30% to comply with MAOP existing pressure tests, new subpart J pressure tests, in-line inspection that confirms the design MAOP.

No deadline has been established for completing the tests because more information is needed from individual operator engineering analysis.
EXHIBIT 2
Evaluation of MAOP Testing for In-Service Transmission Pipelines by EN Engineering

Evaluation of MAOP Testing
for In-Service Transmission Pipelines

Prepared for:
American Gas Association

Prepared by:
ENengineering

June 20, 2013
Notice and Disclaimer

The work associated with this project has been performed by EN Engineering with funding from for the American Gas Association (AGA).

This report addresses general cost analyses, timelines and potential barriers related to MAOP testing of in-service transmission pipelines and transmission pipeline replacement projects. It was not intended for this study to provide detailed engineering project analysis related to costs and timelines, but rather broad ranges in order to provide an order of magnitude. Cost estimates herein are based on a preliminary analysis and are contingent on numerous variables specific to a particular operator, including, but not limited to, state and federal regulatory requirements, macro-economic market conditions, geographic area and system infrastructures.

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</thead>
<tbody>
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<td>AGA</td>
<td>American Gas Association</td>
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<tr>
<td>BLM</td>
<td>Bureau of Land Management</td>
</tr>
<tr>
<td>CFR</td>
<td>Code of Federal Regulations</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
</tr>
<tr>
<td>CPUC</td>
<td>California Public Utilities Commission</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>HCA</td>
<td>High Consequence Area</td>
</tr>
<tr>
<td>HDD</td>
<td>Horizontal Directional Drilling</td>
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<tr>
<td>ILI</td>
<td>In-line Inspection</td>
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<td>LDC</td>
<td>Local Distribution Company</td>
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<td>Liquefied Natural Gas</td>
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<td>Maximum Allowable Operating Pressure</td>
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<td>NTSB</td>
<td>National Transportation Safety Board</td>
</tr>
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<td>O&amp;M</td>
<td>Operations and Maintenance</td>
</tr>
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<td>PHMSA</td>
<td>Pipeline and Hazardous Materials Safety Administration</td>
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<td>Potential Impact Radius</td>
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<td>Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011</td>
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<tr>
<td>PT</td>
<td>Pressure Test</td>
</tr>
<tr>
<td>ROW</td>
<td>Right-of-Way</td>
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<td>SMYS</td>
<td>Specified Minimum Yield Strength</td>
</tr>
<tr>
<td>TIMP</td>
<td>Transmission Integrity Management Plan</td>
</tr>
<tr>
<td>TVC</td>
<td>Traceable, Verifiable and Complete</td>
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</tbody>
</table>
1.0 EXECUTIVE SUMMARY

As a result of a number of pipeline incidents over the past several years, the Pipeline Hazardous Materials Safety Administration (PHMSA) is considering whether or not transmission pipelines with no prior pressure test should be pressure tested to confirm the currently established Maximum Allowable Operating Pressure (MAOP) and whether or not pressure testing should be performed to a minimum of 1.25 times MAOP. Additionally, PHMSA will be developing future rulemaking to address cases where transmission pipeline operators have records that are insufficient to confirm the established MAOP in Class 3, Class 4 and Class 1 and 2 HCA locations.

Until firm rulemaking is established and released, the ramifications are unknown. However, various mandates and recommendations from entities such as PHMSA, the National Transportation Safety Board (NTSB) and the California Public Utility Commission have provided some indication of what future rulemaking might contain.

The American Gas Association (AGA) retained EN Engineering to perform a study with the objective of providing analysis on the impacts increased testing requirements may have on the industry as a whole. As part of this study, the options of testing, replacement and lowering operating pressure of in-service transmission pipelines were reviewed.

In order to gauge the potential impacts to the industry, fifty-six (56) AGA member companies (52,444 transmission miles) provided advance data on their anticipated reporting for the calendar year 2012 PHMSA Transmission Annual Report which included information pertaining to:

- Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
- Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
- Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

Records

To date, the industry has been generally successful at confirming MAOP based on records for Class 3, 4 and Class 1 and 2 High Consequence Areas (HCA). Preliminary data from AGA member companies suggests for those areas reviewed, approximately 87% meet the “traceable, verifiable and complete” criteria for the MAOP determination method utilized.

Impact of Additional Testing Requirements

If regulations are expanded to require testing on previously untested lines, the impact to industry will be significantly greater than that related to testing lines with incomplete records. Data suggests:

- 32% of the respondent transmission mileage will be subject to additional testing if MAOP determination methodologies related to historic operating pressures, §192.619(a)(3) and §192.619(c ), are removed from federal pipeline code.
- 9% of the respondent mileage will be subject to additional testing if §192.619(c), the “grandfather clause”, is removed from federal pipeline code.
34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing up to 1.25 times MAOP, including within Class 1 locations.

**Configuration**

Typically, it is not feasible to remove pipe from service for pressure testing if the line is a single source feed, or if system capacity requirements preclude interruption of service. Based on discussions with several AGA member companies, the following percentages of pipe infrastructure cannot be removed from service for the pressure tests:

- 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test.
- 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP.
- 42% of pipe with a pressure test less than a 1.1 times MAOP or no documented pressure test.

Comparisons of the distributions of pipe size and of class location show a strong correlation between AGA member company transmission lines and all pipelines classified as intrastate pipeline. Interstate companies have different operating and size characteristics and are excluded from any analysis in this study.

**Cost Estimates**

Scenario-based cost estimates were developed to project the potential cost impact to operators in the United States:

- For all AGA companies, the estimated cost to complete MAOP testing for in-service gas transmission pipelines in Class 3, 4 and HCA locations is $11.9 billion. If regulations mandate testing in all class locations, this cost increases to $24.7 billion.
- Extrapolation to all intrastate pipelines increases estimated costs from $23.0 billion to $49.6 billion respectively.

**Barriers**

Individual surveys and focused discussions were conducted with select operator companies and service providers to gage their impression of areas that could be significantly impacted by increased testing requirements. Impacts to the industry as a result of increased requirements include:

- Current workforce levels will need to expand to support current pipeline safety programs as well as significant additional testing requirements. The availability of experienced contractors will be an issue.
- Permitting can significantly lengthen the overall life cycle of a testing or replacement project.
- The occurrence of failures during a testing project can be unpredictable.
- The existing configuration of a pipeline has a substantial effect on the scope, duration, and cost of a hydrostatic test project.
• Single source pipelines and/or peak customers for whom the operator’s system will be unable to supply gas, or an adequate amount of gas, while a section of pipeline is tested may require a large volume of temporary gas supply.

• Addressing transmission lines which are geographically and operationally influenced by the locale and operational characteristics of the supplied distribution systems.

• Testing and replacement concentrated on “shoulder months” result in a lengthening of the duration of an operator’s expanded MAOP testing plans and increased logistical constraints to complete.

• Ratepayer advocacy groups objecting to the higher cost alternative of pipe replacement.

• Population related development in the immediate proximity of rights-of-way and/or infrastructure may limit the availability of alignments for replacement projects.

• If the industry mobilizes a large number of replacement projects in a short time frame, the availability of materials for infrastructure such as line pipe and valves, may become limited.

Conclusions

Specific regulation changes for the remainder of the country are unknown at this time, but the expansion of regulations will have a considerable effect to the industry. While the specific relationships of scope and costs are difficult to assess, the expansion of regulations in California has resulted in additional costs resulting from testing and replacement of in-service transmission pipelines. Actual costs will be driven by the specific testing and timeline mandates implemented by PHMSA and state jurisdictional authorities. Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. A carte blanche application across all operators in a short time frame of a standardized method for MAOP testing will require extraordinary resources.
2.0 INTRODUCTION

2.1. Background

As a result of a number of pipeline incidents over the past several years, the Pipeline Hazardous Materials Safety Administration (PHMSA) is considering whether transmission pipelines with no prior pressure test should be pressure tested to confirm the currently established MAOP. Additionally, PHMSA will be developing future rulemaking to addresses cases where transmission pipeline operators have records that are insufficient to confirm the established MAOP in Class 3, Class 4 and Class 1 and 2 HCA locations.

Until firm rulemaking is established and released, the ramifications are unknown. However, various mandates and recommendations, such as those discussed in the subparagraphs below, have provided some indication as to options PHMSA may be considering.

2.1.1. Pipeline Safety Reauthorization

On January 3, 2012, the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” (PSA 2011) was signed into law. Amongst the various mandates was section number 23 on Maximum Allowable Operating Pressure. In short, this section required each owner or operator of a pipeline facility to:

- Conduct a verification of pipeline records for transmission pipelines located in a Class 3, and Class 4 locations and Class 1 and 2 HCAs to verify that records confirm the established MAOP.
- Identify and submit information indicating where records are insufficient to confirm the established MAOP.

Additionally, the section required the Secretary of Transportation to:

- For those lines where records were unable to verify the established MAOP, require the owner or operator to reconfirm the MAOP as expeditiously and economically as feasible.
- Determine the actions that are appropriate for a pipeline owner or operator to take in order to maintain pipeline safety until the MAOP is confirmed.
- Issue regulations for conducting tests to confirm the material strength of previously untested transmission pipelines located in an HCA and operating at a pressure greater than 30% of the specific minimum yield strength.

As a result of PSA 2011, pipeline operators have been working to review and confirm records to support the established MAOP.
2.1.2. **NTSB Recommendations**

As a result of the San Bruno incident, the National Transportation Safety Board (NTSB) issued multiple Safety Recommendations, including these to PHMSA:

- Amend Title 49 Code of Federal Regulations §192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P-11-14)

- Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure. (P-11-15)

- Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines. (P-11-17)

2.1.3. **PHMSA Reporting**

As a result of PSA 2011 and recommendations from the NTSB, PHMSA modified Form F7100.2-1 "Annual Report for Calendar Year 2012 Natural and Other Gas Transmission and Gathering Pipeline Systems" (Gas Transmission Annual Report) in order to collect additional information from operators to use during the development of future rulemaking.

Modifications to the Gas Transmission Annual Report included:

- Modifications to Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.

- The addition of Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.

- The addition of Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

2.1.4. **California Operator Mandates**

In addition to mandates and changes at the federal level, the state of California has superseded federal regulations by issuing various rulemakings and decisions to pipeline operators within the state of California. Amongst those issued, in June of 2011, the California Public Utility Commission (CPUC) issued decision 11-06-017 which ordered all California natural gas operators to develop and file a comprehensive pressure testing plan.

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1 "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno California September 9, 2010”; National Transportation Safety Board
2.2. **Study Scope and Objectives**

In order to help the AGA and member companies understand the potential impact increased testing requirements could have on member companies, the AGA sought qualified firms to perform an engineering study. This report was prepared in response to the AGA request for an evaluation of MAOP testing inside and outside of High Consequence Areas.

This report addresses the following request from AGA:

- **Item 1:** Document cost estimates for MAOP hydrotesting and / or replacement of Class 1 and 2 HCA transmission pipe and Class 3 and 4 transmission pipe. This study should also attempt to conduct an analysis of pipe outside of HCAs that has not undergone MAOP testing.

- **Item 2:** Discuss timelines for scheduling pressure tests and replacement using sound engineering-based assumptions and empirical data.

- **Item 3:** Incorporate the list of permits necessary for various engineering projects and the costs and timeframes for each to be obtained.

- **Item 4:** List the barriers an operator would encounter when undergoing pressure tests and outline the potential costs associated with overcoming these issues.

- **Item 5:** Look at resource availability (i.e. the number of contractors with sufficient skill to assist the operator in pressure testing operations and pipe replacement) and identify operational bottlenecks if multiple operators are conducting tests simultaneously.

- **Item 6:** Outline the barriers to simply “extrapolating” the California Plan.

- **Item 7:** Discuss potential conflict between potential regulatory requirements to expand 49 CFR Subpart O assessments outside HCAs at the same time as untested pipe inside and outside of HCAs is pressure tested.

2.3. **Study Terminology**

Throughout the course of this study, several key terms are utilized as defined below:

- **MAOP Record Verification:** The use of records that accurately reflect the physical and operational characteristics of the pipeline (i.e. design, pressure test, pressure history and other operating information). The records should be traceable, verifiable and complete.

- **MAOP Confirmation:** Reconfirming the MAOP established using existing methods in §192.619.

- **MAOP Testing:** Congressional mandate of certain untested pipe to undergo a material strength test (usually hydrotesting) or an alternative testing method such as specialized internal inspection, regardless of whether records are traceable, verifiable, or complete.
3.0  ANALYSIS OF PHMSA REPORTING DATA

3.1.  Data from AGA Member Companies

3.1.1.  Background

EN Engineering worked in conjunction with the AGA to obtain preliminary representative data and information pertaining to the calendar year 2012 Gas Transmission Annual Report, specifically parts K, Q and R, from AGA member companies representing over fifty thousand transmission miles. It was acknowledged that at the time of the AGA survey, operators were still undergoing record validation efforts and actual numbers reported to PHMSA (due by June 15, 2013) could potentially vary. However, it was agreed by all parties that these numbers presented a reasonable representation of what would actually be submitted to PHMSA.

In December 2012 the AGA sent surveys to member companies soliciting information pertaining to the following sections of the Gas Transmission Annual Report for calendar year 2012:

- Part K: Miles of Transmission Pipe by Specified Minimum Yield Strength.
- Part Q: Gas Transmission Miles by §192.619 MAOP Determination Method.
- Part R: Gas Transmission Miles by Pressure Test (PT) Range and Internal Inspection.

3.1.2.  Survey Response

The AGA obtained information back from 56 member companies which represented 52,444 transmission miles, with the majority being intrastate mileage. Approximately 8,800 miles of the total reported mileage is considered interstate.

Due to data and reporting discrepancies, responses from two (2) member companies were not considered; however, in portions of the study, particularly cost analysis scenarios, characterizations based on 54 company responses were applied to these two (2) companies in an effort to provide analysis reflecting all member companies contributing to the study.

In the analysis of data pertaining to MAOP determination method (see section 3.2 and 3.3), data from eight (8) member companies was not considered due to discrepancies in the reported data.

3.1.3.  Focused Discussions with Operators

In addition to the operator surveys, focused discussions with three (3) operators with assets within the state of California, as well as five (5) operators with assets outside the state of California were held. The objectives of these discussions included:

- Understanding timelines, schedules, cost variations and implementation results for MAOP testing projects.
- Identify anticipated barriers to increased testing requirements.
- Calibrate assumptions and estimates made during the study.

The non-California companies were selected to represent the AGA membership as a whole. The California operators were interviewed to capture any additional insight derived from the implementation of their MAOP testing plans. Interviewed companies varied in geographic region, operational environment, system size, and amount of transmission pipe that has not been pressure tested to 1.25 times MAOP.

3.2. **Incomplete Records**

Item 23(c) in PSA 2011 mandates that the Secretary of Transportation require pipeline operators to reconfirm MAOP for those lines where records were unable to reconfirm the established MAOP.

Part Q of the AGA survey asked operators to provide information pertaining to incomplete records in Class 3, Class 4, Class 3 and 4 HCA and Class 1 and 2 HCA locations. **Figure 1**, derived from preliminary data provided by AGA survey respondents, shows the breakdown of incomplete records based on miles and class location.

![Figure 1: Percentage of Miles with Incomplete Records by Class / HCA Location](image)

For the purposes of this study, EN Engineering assumes that any future requirements related to the testing of locations with incomplete records will be encompassed by larger scale issues such as deleting §192.619(a)(3) and §192.619(c) from federal pipeline code. As a result, statistics and analysis specific to implications related to the MAOP testing of locations with incomplete records are not formally identified as a subset in this study.

3.3. **Miles by MAOP Determination Method**

In Safety Recommendation P-11-14, the NTSB is essentially recommending that PHMSA amend pipeline safety code to eliminate the “grandfather clause”. For the purposes of this analysis, EN Engineering is considering the "grandfather clause" to be both §192.619(a)(3) and §192.619(c) of 49 CFR Part 192. Technically, §192.619(c) is the “grandfather clause”
and addresses pre-code (prior to November 12, 1970) pipe on a stand-alone basis. However, similar language was placed into §192.619(a) in order to compare historic operations against the other MAOP determination methods, in the event, for example the §192.619(a)(1) calculation for that particular line is higher than this pre-1970 operating pressure, thus ensuring §192.619(a)(3) would be the limiting factor. As a result, any revisions to code in terms of the “grandfather clause” could affect both sections of code.

Part Q of the AGA survey requested information pertaining to the subsection of §192.619 serving as the limiting factor for establishing MAOP. Of particular significance, this provided information on the potential population of miles subject to the “grandfather clause”.

Figure 2 graphically illustrates the number of transmission miles by MAOP determination method for 48 respondent AGA member companies. As discussed previously in section 3.1.2, due to discrepancies across the various parts of the survey, data from eight (8) respondent companies was not included in this analysis.

![Gas Transmission Miles by §192.619 MAOP Determination Method](source)

While pressure test was reported as the MAOP determination method for the majority of mileage, a significant portion (32%) of the respondent mileage has established MAOP by historic operating pressure, and will be affected if these methodologies are removed from federal pipeline code. By strict interpretation of the “grandfather clause”, if §192.619(c) is removed from federal pipeline code, 9% of the respondent mileage will be affected.

3.4. Miles by Class Location and HCA

PSA 2011 and NTSB reports include recommendations and mandates specific to HCAs and certain class locations. Parts Q and R from the AGA survey provide information related to HCAs and class locations, which is presented in Figure 3.
Based on the data, approximately 23% of the mileage operated by the AGA survey respondents is in an urban, heavily congested area.

49 CFR Part 192 Subpart O was designed to incorporate population density as well as operating characteristics (i.e. diameter, pressure) for a specific pipe section to evaluate risk. Using a prescribed equation, the Potential Impact Radius (PIR) was calculated by pipeline operators and smaller diameter, lower pressure pipelines typically did not create an HCA. Based on the survey data, approximately 43% of the Class 3 and 4 mileage is considered non-HCA. Although per Subpart O non-HCAs are considered a lower risk, Class 3 and 4 non-HCAs are not distinguished as a lower risk in any of the various safety recommendations addressed in this report.

### 3.5. Miles by Pressure Test Range

In Safety Recommendation P-11-15, the NTSB recommended that PHMSA amend Title 49 of the Code of Federal Regulations to essentially require pipeline transmission operators to perform a pressure test to at least 1.25 times MAOP. Current federal pipeline regulations (49 CFR §192.619) require that pipelines installed after November 11, 1970 have a post-construction pressure test with a test factor commensurate with class location as indicated in the table below²:

²Table adapted from 49 CFR Part 192 §192.619(a)(2)(ii)
Table 1: Pressure Test Factors

<table>
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<th>Class Location</th>
<th>Test Pressure Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.5</td>
</tr>
<tr>
<td>4</td>
<td>1.5</td>
</tr>
</tbody>
</table>

As noted in the table above, current regulations allow a safety factor in Class 1 locations that is less than the safety factor recommended by the NTSB. As a result, any changes to regulations resulting from NTSB Safety Recommendation P-11-15 will primarily affect pipelines located in Class 1 areas, but will also affect lines in all class locations with insufficient testing records.

Part R of the AGA survey asked operators for information pertaining to the miles of transmission pipe with:

- A pressure test greater than or equal to 1.25 times MAOP.
- A pressure test between 1.1 and 1.25 times MAOP.
- No documented pressure test or a pressure test less than 1.1 times MAOP.

Figure 4 represents the data as reported by 54 AGA member companies.

Figure 4: Miles by Pressure Test Range

As indicated by the graphic, approximately two thirds of the respondent mileage has been subject to a pressure test of at least 1.25 times MAOP.

Based on this data population and dependent upon the outcome of future rulemakings:

- 34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing of in-service transmission lines up to 1.25 times MAOP for all class locations.
The graphic below further breaks down Figure 4 to include class locations in each of the three pressure test ranges.

![Pie chart showing pressure test ranges and class locations.]

**Figure 5: Miles by Pressure Test Range and Class / HCA**

Additional observations from this data population include:

- 18.5% of pipe with a less than 1.25 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.
- 21.6% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.

### 3.6. Companies with Pressure Test Less than 1.25 times MAOP or No Documented PT

The transmission systems for 42 of the 54 AGA member companies in the data population contain pipe that has been pressure tested to less than 1.25 times MAOP, with twelve (12) companies having no transmission pipe that has been tested to less than 1.25 times MAOP and one (1) company having 100% of their transmission pipe being tested to less than 1.25 times MAOP.

The twelve (12) companies with no miles of transmission pipe potentially requiring MAOP testing each operate less than 260 miles of transmission pipe and seven (7) of these operate less than 50 miles of transmission pipe. **Figure 6** contains a histogram that shows the distribution of company transmission systems that have been pressure tested to less than 1.25 times MAOP or have no documented pressure test.
3.7. **Ability for Internal Inspection**

In Safety Recommendation P-11-17, the NTSB recommended that PHMSA require all gas transmission pipelines be configured to accommodate in-line inspection (ILI) tools. As part of the revised Gas Transmission Annual Report for calendar year 2012, PHMSA added Part R in order to gather information on the ability to inspect pipelines using ILI tools.

Per the annual report instructions, PHMSA considers “internal inspection able” to mean “a length of pipeline through which commercially available devices can travel, inspect the entire circumference and wall thickness of the pipe, and record or transmit inspection data in sufficient detail for further evaluation of anomalies”.

The table below presents the information reported by 54 of the AGA respondents. Based on this information, more than 60% of the respondent mileage is considered ILI-not able. Approximately 69% of the pipe that has been pressure test to less than 1.25 times MAOP or not pressure tested is considered ILI-not able.

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3 Instructions (rev 12-2012) for Form PHMSA F 7100.2-1 (rev 12-2012); page 18
3.8. **Ability to Remove a Section of Pipe from Service**

In some cases, it may not be feasible to remove pipe from service to complete a pressure test for the following reasons:

- Single source feed for a town, distribution center, or an industrial customer.
- System capacity requirements.

As a part of the focused discussions with select operating companies, a second survey was issued to those companies in an effort to collect additional information about their specific pipeline systems and to drill deeper into the data submitted during the original survey. Five (5) companies participated in this effort, representing approximately 20% of the pipe reported by the 54 AGA company respondents that has not been pressure tested to 1.25 times MAOP. Data gleaned from the survey results and operator discussions indicates the following percentages of pipe infrastructure cannot be removed from service for the pressure tests:

- 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test.
- 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP.
- 42% of pipe with a pressure test less than a 1.1 times MAOP or no documented pressure test.

3.9. **Summary of Key Statistics**

Information gathered from the survey responses for the AGA member companies is the foundation for this study and is utilized and referenced throughout the report. Below is a summary of key data and characterizations:

- 32% of the respondent transmission mileage will be subject to additional testing if MAOP determination methodologies related to historic operating pressures, §192.619(a)(3) and §192.619(c), are removed from federal pipeline code.
• 9% of the respondent mileage will be subject to additional testing if §192.619(c), the “grandfather clause”, is removed from federal pipeline code.

• 34% of the respondent mileage could be subject to additional testing if future rulemaking requires testing of in-service transmission lines up to 1.25 times MAOP for all class locations.

• 18.5% of pipe with a less than 1.25 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA locations.

• 21.6% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test is located in Class 3, 4 or a Class 1 or 2 HCA.

• 31% of pipe with less than a 1.25 times MAOP pressure test or no documented pressure test cannot be removed from service.

• 4% of pipe with a pressure test greater than 1.1 times MAOP but less than 1.25 times MAOP cannot be removed from service.

• 42% of pipe with a less than 1.1 times MAOP pressure test or no documented pressure test cannot be removed from service.
4.0 MAOP TESTING OPTIONS

Although other viable options exist for the confirmation of MAOP, the scope of this study focuses on:

- Strength testing
- Pipe replacement
- Lowering operating pressure

Strength testing, often the most cost effective of this subset of options for establishing MAOP, may be the initial choice of an operator, but the implementation of such testing may encounter various challenges as discussed further in this report, and pipe replacement or lowering operating pressure may become more feasible options.

4.1. Testing

A pressure test involves shutting in a pipeline and pressurizing it with a test medium to a specified minimum pressure for an extended length of time. Subpart J of federal pipeline code allows for pressure tests to be performed with natural gas, air, inert gas, or water. Typically pressure testing on transmission piping operating at greater than 30% SMYS is performed using water. For the purposes of this study, testing refers to hydrostatic testing, which is a subset of strength testing.

During a hydrostatic testing project for in-service transmission pipelines, the section of the pipeline that is being tested is taken out of service for the duration of the construction portion of the project. The length of time that the pipeline is out of service may vary from one (1) month to three (3) or more months depending on the scope of work required to prepare the pipe for testing. The actual test is a relatively short duration event (approximately eight hours). Planning, pipe modifications, permitting, etc. can be logistically complicated and extend the project timeframe.

4.2. Pipe Replacement

Pipeline replacement involves installing a new main that will provide service to an area of the system that is currently supplied by a pipeline that has not been pressure tested to the required pressure level. Depending on land and system constraints, the replacement line could be installed adjacent to the current pipeline in a parallel right-of-way or in a new location. The replacement pipeline is installed following modern design and construction standards and in conformance with current regulatory requirements. As part of modern construction practices and regulatory requirements a precommission pressure test is performed to establish the required safety factor.

During construction of the replacement pipeline the existing pipeline can remain in-service. This is beneficial for single source / peak pipelines that cannot be taken out of service or may require a large amount of temporary gas supply to ensure continuous operation.

Another benefit of main replacement is that the installation is performed using modern steel/pipeline and coating systems.
4.3. **Lowering Operating Pressure**

Lowering operating pressure involves decreasing the MAOP of a pipeline to a pressure level with a margin of safety lower than the pressure level the pipe previously operated at. When using this method, a company is treating the documented operating pressure on the pipeline as the pressure test. The new maximum operating stress on the pipeline is a margin of safety (1.25 minimum) lower than the maximum stress that the pipeline has experienced in operation. The pipeline at its new operating pressure has a safety factor equivalent to a pipeline that was pressure tested to 1.25 times the MAOP. From a system integrity and risk management perspective, lowering the operating pressure, using the method discussed in this section, is equally as beneficial as performing a pressure test to 1.25 times MAOP.

Example of Lowering Pressure:

- **Current MAOP:** 1000 psig
- **Documented Operating Pressure:** 970 psig
- **Revised MAOP = 970 psig / 1.25 Safety Factor = 776 psig**

Lowering of operating pressure has significantly lower direct construction costs than either hydrostatic testing or main replacement. However, lowering pressure reduces system capacity and potentially causes long term operational restrictions that the other options do not create. Depending on the system design and capacity requirements, a new pipeline may be required to account for the capacity loss, causing the costs to approach those of replacement.
5.0 COST ANALYSIS

5.1. Data Correlations

5.1.1. Background

As part of this study, PHMSA transmission annual report data was reviewed and comparisons were made in order to understand if various categorizations applied to the AGA respondent companies could be extrapolated to the entire intrastate population and the transmission population (intrastate and interstate).

5.1.2. Data Set Comparison – Nominal Pipe Size

Based on information reported to PHMSA by operators on the calendar year 2011 Transmission Annual Report, the entire population of intrastate transmission lines is comprised of approximately 108,000 miles, largely driven by the large mileage of intrastate lines operated by midstream pipeline operators. The data population for the 56 AGA respondent companies is based on data provided as a result of the AGA survey, as well as information reported to PHMSA on the Transmission Annual Report. Approximately 8,800 miles of the total population (52,444 miles) of AGA respondent mileage are interstate miles which are included in the AGA respondent data set.

Figure 8 represents nominal pipe size groupings by percentage of the total population as reported in the AGA survey and to PHMSA by the 56 AGA respondent companies and intrastate pipeline operators, respectively. As illustrated, the distribution of pipe size versus the percentage of the total population is similar for both data sets.
Figure 9 represents the same information as presented in Figure 8, with the addition of the pipe size distribution for the interstate pipeline operators. The data indicates that the interstate pipelines are an independent data set due to the distribution of pipe sizes across the population, primarily driven by the large distribution of pipe greater than 20-inches as compared to the AGA respondent companies and the intrastate population.
5.1.3. **Data Set Comparison – Class Location**

*Figure 10* shows the distribution of class location by the percentage of the total population for both AGA respondent mileage and intrastate transmission mileage as obtained from the PHMSA website. As indicated in the chart, the class distribution of pipe is similar for both data sets.

![Figure 10: AGA Respondent and Intrastate Comparison – Class Location](image)

*Figure 10* represents the same information as presented in *Figure 10* with the addition of the class location distribution for the interstate pipeline operators. The data indicates that the interstate pipelines are an independent data set due to the distribution of pipe across class locations, primarily driven by a higher percentage of line traversing rural areas.

![Figure 11: AGA, Intrastate, Interstate Comparison – Class Location](image)

Since the interstate transmission mileage is an independent data set, cost analyses presented in the following sections were performed for the AGA respondent mileage and the total intrastate transmission mileage only.
5.2. Regional Variations to Construction Costs

In 2011, the Oil and Gas Journal published a study on various regional construction costs which indicated that construction costs, particularly for labor, rights-of-way and miscellaneous factors, vary by region of the United States\(^5\). For this study, miscellaneous factors include items such as engineering, supervision and surveying.

**Figure 12** summarizes the regional cost factors derived from the study. Since this study was based on FERC project data from 1992 to 2008, cost impacts resulting from industry impacts such as recent large construction projects and recent failures are not reflected.

![Regional Construction Costs](image)

**Figure 12: Regional Construction Costs**

Cost factors will be utilized and discussed further later in this report when presenting regional cost estimates.

5.3. Regional Pipe and Nominal Pipe Size Distribution

5.3.1. 56 Responding AGA Member Companies

The regional pipe size distribution for the 56 member companies that responded to the initial AGA survey was compiled using 2011 PHMSA Transmission Annual Report data\(^6\). Approximately 8,800 miles included in this data are classified as interstate miles. The pipe size distribution for the 56 companies is shown by region in Table 2.

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<td>West</td>
<td>1.92</td>
<td>2.2</td>
<td>1.00</td>
<td>1.00</td>
<td>1.28</td>
</tr>
</tbody>
</table>

\(^{*}\) Developed FERC Project Data From 1992 - 2008

---


Table 2: Regional Pipe Size Distribution – 56 Reporting AGA Member Companies

<table>
<thead>
<tr>
<th>Region</th>
<th>&lt;6&quot;</th>
<th>6/8&quot;</th>
<th>10/12/14&quot;</th>
<th>16/18/20&quot;</th>
<th>22/24&quot;</th>
<th>26/30&quot;</th>
<th>34/36&quot;</th>
<th>≥40&quot;</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central</td>
<td>21%</td>
<td>30%</td>
<td>16%</td>
<td>22%</td>
<td>2%</td>
<td>9%</td>
<td>0%</td>
<td>0%</td>
<td>10,307</td>
</tr>
<tr>
<td>Northeast</td>
<td>5%</td>
<td>14%</td>
<td>28%</td>
<td>28%</td>
<td>23%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>3,849</td>
</tr>
<tr>
<td>Midwest</td>
<td>6%</td>
<td>20%</td>
<td>24%</td>
<td>20%</td>
<td>10%</td>
<td>14%</td>
<td>6%</td>
<td>1%</td>
<td>11,155</td>
</tr>
<tr>
<td>Southeast</td>
<td>11%</td>
<td>32%</td>
<td>39%</td>
<td>12%</td>
<td>4%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>5,107</td>
</tr>
<tr>
<td>Southwest</td>
<td>14%</td>
<td>25%</td>
<td>23%</td>
<td>21%</td>
<td>3%</td>
<td>10%</td>
<td>4%</td>
<td>0%</td>
<td>9,218</td>
</tr>
<tr>
<td>Western</td>
<td>5%</td>
<td>19%</td>
<td>20%</td>
<td>18%</td>
<td>6%</td>
<td>12%</td>
<td>18%</td>
<td>2%</td>
<td>12,808</td>
</tr>
<tr>
<td>Total</td>
<td>10%</td>
<td>23%</td>
<td>23%</td>
<td>20%</td>
<td>6%</td>
<td>10%</td>
<td>6%</td>
<td>1%</td>
<td>52,444</td>
</tr>
</tbody>
</table>

5.3.2. All Intrastate Companies

Similarly, the regional pipe size distribution for all intrastate pipe in the United States was compiled from the 2011 PHMSA Transmission Annual Report data and is shown in Table 3. Approximately 40% (approximately 43,700 miles) of the miles shown in this table are miles operated by the 56 AGA members that responded to the survey.

Table 3: Regional Pipe Size Distribution – All US Intrastate Miles

<table>
<thead>
<tr>
<th>Region</th>
<th>&lt;6&quot;</th>
<th>6/8&quot;</th>
<th>10/12/14&quot;</th>
<th>16/18/20&quot;</th>
<th>22/24&quot;</th>
<th>26/30&quot;</th>
<th>34/36&quot;</th>
<th>≥40&quot;</th>
<th>Total Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central</td>
<td>26%</td>
<td>39%</td>
<td>20%</td>
<td>13%</td>
<td>3%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>17,300</td>
</tr>
<tr>
<td>Northeast</td>
<td>2%</td>
<td>18%</td>
<td>34%</td>
<td>27%</td>
<td>15%</td>
<td>4%</td>
<td>0%</td>
<td>0%</td>
<td>3,818</td>
</tr>
<tr>
<td>Midwest</td>
<td>7%</td>
<td>22%</td>
<td>24%</td>
<td>21%</td>
<td>9%</td>
<td>12%</td>
<td>4%</td>
<td>0%</td>
<td>14,375</td>
</tr>
<tr>
<td>Southeast</td>
<td>10%</td>
<td>36%</td>
<td>35%</td>
<td>12%</td>
<td>4%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
<td>11,144</td>
</tr>
<tr>
<td>Southwest</td>
<td>8%</td>
<td>20%</td>
<td>22%</td>
<td>24%</td>
<td>10%</td>
<td>8%</td>
<td>6%</td>
<td>2%</td>
<td>47,328</td>
</tr>
<tr>
<td>Western</td>
<td>5%</td>
<td>18%</td>
<td>22%</td>
<td>18%</td>
<td>6%</td>
<td>12%</td>
<td>17%</td>
<td>2%</td>
<td>13,451</td>
</tr>
<tr>
<td>Total</td>
<td>10%</td>
<td>25%</td>
<td>24%</td>
<td>20%</td>
<td>8%</td>
<td>7%</td>
<td>5%</td>
<td>1%</td>
<td>107,416</td>
</tr>
</tbody>
</table>

The ratio of intrastate miles for the 56 AGA responding companies to total intrastate miles in each region is shown in Figure 13. The graph shows that there are a large number of miles in the Southwest region (Texas, Louisiana, Oklahoma, etc.) from companies that did not respond to the AGA survey or are not members of AGA. A large portion of these miles are likely associated with midstream companies in gas production areas.

A review of the data for interstate companies shows a shift to predominantly larger diameter pipeline, as well as a larger percentage of mileage in Class 1 and 2 locations when compared to the intrastate companies. Because of these different
characteristics, traditional interstate pipelines operate at higher pressures and rely more heavily on ILI.

![Figure 13: Comparison of AGA Respondent and US Intrastate Total Intrastate Population](image)

**5.4. MAOP Testing Cost Estimates**

For the public, utility commissioners, and pipeline operators, the analysis of economic factors is important in the decision of whether to pressure test, lower the operating pressure, or replace the pipeline. These decisions are influenced strongly by the specific gas supply market, customer base characteristics and delivery contracts, as well as other project constraints. Regional environmental and political considerations will also factor into the decision process.

In order to help quantify the potential impact of increased testing requirements to intrastate operators, cost estimate ranges for typical hydrostatic testing of in-service transmission pipelines and main replacement projects were developed. The cost estimates were created using EN Engineering internal project experience as well as project cost data collected during discussions with select AGA Member companies. These companies had varying levels of experience with hydrostatic testing of in-service pipe (extremely limited to several hundred miles) and the data provided was a collection of engineering cost estimates and project experience. Additionally, these companies included one with a large percentage of its system in rural areas as well as companies with experience performing tests in urban (Class 3, 4 and HCA) locations with considerable environmental constraints. All companies interviewed had experience with pipeline replacement / installation and data provided was from recent project experience or engineering estimates.

**5.4.1. Cost Estimate - Background**

EN Engineering project experience and the AGA member company input identifies class location as a primary variable in the cost of a project. Construction in an urban environment typically includes: increased permitting requirements, restrictions on working hours and equipment, a large amount of work in or crossing road right-of-ways, higher material costs, an increased contractor work force (traffic control, etc.), and longer project duration. Urban areas also have limited right-of-way availability with higher acquisition costs.
Economies of scale are also a main driver of project cost, especially for hydrostatic testing projects that have a high percentage of fixed costs. A hydrostatic test project with test segment lengths of less than 0.75 miles can have a per mile cost more than five (5) times that of a project with test segment lengths greater than 2.0 miles. Typically, due to construction and system design constraints, urban areas will have shorter test segments than rural areas, further increasing the price variation between Class 1 and 2 non-HCA locations and Class 3, 4 and HCA areas.

As discussed in section 3.5, approximately 18.5% of pipe that has been pressure tested to less than 1.25 times MAOP or has no documented pressure test is in a Class 3, 4 or HCA location. The remaining 81.5% of pipe is located in a Class 1 or 2 non-HCA location. In order to take into consideration class location and the various challenges, and presumably higher costs associated with MAOP testing and replacement in an urban environment, weighted averages based on cost estimate ranges were developed. These weighed averages assume pipe in a Class 1 or 2 non-HCA location has a minimum cost and that pipe in Class 3, 4 or HCA locations has a maximum cost.

The cost estimate ranges developed in this study intend to account for typical variation of the factors that affect the scope of a hydrostatic test or pipe replacement project.

5.4.2. Cost Estimate – Hydrostatic Test

Current industry experience with in-service hydrostatic testing is limited. As a result, best effort cost ranges were developed utilizing available data and engineering judgment. The minimum and maximum cost range estimates for a typical hydrostatic test project based on the central region (cost factor of 1.0) are shown Table 4. These cost estimates exclude consideration of atypical events such as testing failures.

In this study hydrostatic testing cost estimates and calculations are regionalized using the labor factor shown in Figure 12. Since labor costs account for a high percentage of the overall cost of a hydrostatic test project, the labor factor is utilized in these estimates rather than the overall construction factor.

7 Weighted Average = Min * (% of Pipe Class 1,2 Non HCA)+Max*(% Class 3, 4, HCA)
Table 4: Hydrostatic Testing Project Cost Estimates of In-Service Pipe for Central Region

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Minimum Estimate ($/Mile)</th>
<th>Maximum Estimate ($/Mile)</th>
<th>Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6&quot;</td>
<td>108,000</td>
<td>1,287,500</td>
<td>326,400</td>
</tr>
<tr>
<td>6/8&quot;</td>
<td>111,600</td>
<td>1,718,800</td>
<td>409,200</td>
</tr>
<tr>
<td>10/12/14&quot;</td>
<td>117,000</td>
<td>1,718,800</td>
<td>413,600</td>
</tr>
<tr>
<td>16/20&quot;</td>
<td>185,400</td>
<td>1,822,900</td>
<td>488,600</td>
</tr>
<tr>
<td>22/24&quot;</td>
<td>283,500</td>
<td>2,369,800</td>
<td>669,900</td>
</tr>
<tr>
<td>26/30&quot;</td>
<td>314,100</td>
<td>2,790,800</td>
<td>772,700</td>
</tr>
<tr>
<td>34/36/38&quot;</td>
<td>353,300</td>
<td>3,139,700</td>
<td>869,300</td>
</tr>
<tr>
<td>≥40&quot;</td>
<td>397,500</td>
<td>3,284,100</td>
<td>932,100</td>
</tr>
</tbody>
</table>

5.4.3. Cost Estimate – Replacement

Similar to hydrostatic testing projects, the cost range estimates for a typical pipe replacement project based on the central region (cost factor of 1.0) are shown in Table 5. In this study, pipe replacement estimates and calculations are regionalized using the total factor shown in Figure 12. For these cost ranges, the total factor is used since it represents the regional variance of a pipe installation project.

Table 5: Pipe Replacement Project Cost Estimates for Central Region

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Minimum Estimate ($/Mile)</th>
<th>Maximum Estimate ($/Mile)</th>
<th>Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6&quot;</td>
<td>247,500</td>
<td>1,562,500</td>
<td>491,000</td>
</tr>
<tr>
<td>6/8&quot;</td>
<td>1,041,000</td>
<td>1,953,100</td>
<td>1,209,900</td>
</tr>
<tr>
<td>10/12/14&quot;</td>
<td>1,240,200</td>
<td>2,392,700</td>
<td>1,453,600</td>
</tr>
<tr>
<td>16/20&quot;</td>
<td>2,044,200</td>
<td>2,392,700</td>
<td>2,108,700</td>
</tr>
<tr>
<td>22/24&quot;</td>
<td>2,409,700</td>
<td>4,320,400</td>
<td>2,763,600</td>
</tr>
<tr>
<td>26/30&quot;</td>
<td>2,860,100</td>
<td>4,894,600</td>
<td>3,236,900</td>
</tr>
<tr>
<td>34/36/38&quot;</td>
<td>3,583,600</td>
<td>5,468,800</td>
<td>3,932,700</td>
</tr>
<tr>
<td>≥40&quot;</td>
<td>4,208,600</td>
<td>7,031,300</td>
<td>4,731,400</td>
</tr>
</tbody>
</table>

These cost estimates reflect recent project experience and engineering cost estimate information and were developed using the current demand in the industry. A significant shift in construction demand may cause costs to increase. Additionally, these estimates do not reflect the costs associated with pipe replacement in an extreme situation / densely populated city center. In an extreme situation / densely populated city center, the costs may be significantly higher due to the increased complexity and environmental considerations.
populated city center, a 24-inch OD pressure test could cost more than $15 million per mile and a 36-inch OD pipe replacement could cost more than $50 million per mile.

5.5. Cost comparison

At first glance, comparison of testing in-service pipelines versus replacement indicates that testing is the least cost option, particularly for large diameter lines where replacement costs can exceed four (4) times that of testing costs. However, difficult testing scenarios and other considerations can tilt the economics and make other options such as replacement the more prudent option. Costs and considerations companies may include in a hydrostatic test versus replace decision include:

- Condition of current pipe and coating – pipe in poor condition is more susceptible to hydrostatic test failures.
- Pipeline maintenance costs – replacement can reduce annual maintenance costs
- Capacity considerations – replacement allows for system capacity increases.
- Accounting – state accounting and project compensation allowances may influence repair versus replace considerations.

For additional discussion on potential barriers, refer to section 6.

Figure 14 represents a comparison between testing and replacement costs. These numbers are based on the Central Region, which has a cost factor of 1.0. Costs for other regions can be calculated by multiplying the central region costs by the factors listed within Figure 12.

![Figure 14: Cost Comparison - Hydrostatic Test versus Replacement Costs for Central Region](image-url)
5.6. **Potential Costs – 56 AGA Member Reporting Companies**

Minimum-maximum plots were developed to help illustrate the potential cost impact to the 56 AGA member companies that responded to the survey if regulations are changed to require testing on previously untested pipe or to a minimum test factor of 1.25.

From **Figure 4**, based on 54 AGA member responses, the characterization of pressure testing was as follows:

- 34% tested to less than 1.25 times MAOP or no documented pressure test (17,048 miles).
- 27% tested to less than 1.1 times MAOP or no documented pressure test (13,545 miles).

In order to develop cost estimates representative of all 56 companies providing input into the study, the same ratios from **Figure 4** were applied to the remaining two (2) companies. Using these ratios, mileage subject to each pressure test category for the 56 AGA member companies was calculated to be:

- 17,778 miles tested to less than 1.25 times MAOP or no documented pressure test.
- 14,160 miles tested to less than 1.1 times MAOP or no documented pressure test.

Additionally, the minimum-maximum plots assume:

- The pipe size and regional distribution presented in **Table 2**.
- Regional construction factors presented in **Figure 12**.
- The ratios for pressure test groupings, class/HCA groupings, and ability to remove pipe from service are uniform for all regions, class locations and pipe sizes.


The figure below shows regional potential testing costs for the 56 AGA reporting companies to pressure test 17,778 miles of pipe that has not been tested to at least 1.25 times MAOP or has no documented pressure test. The large cost ranges on the graph are indicative of the large amount of uncertainty and the wide range in project scope for a hydrostatic testing project.
5.6.2. **Minimum-Maximum Cost Estimates - Replacement**

The following figure illustrates the regional potential costs to the 56 AGA reporting member companies to replace the same amount of pipe. Although the costs for replacement are higher than for testing, there is a greater predictability of cost for replacement projects as compared to testing projects.

5.6.3. **Cost Scenarios – 56 AGA Respondent Companies**

At the present time, the content of future rulemaking is unknown. As a result, four (4) cost scenarios were reviewed in order to help quantify the economic impact various changes in regulation could have. Projected costs were developed for the following scenarios:

- Scenario 1 – MAOP testing on all pipe, all class locations, not pressure tested to at least 1.25 times MAOP or having no documented pressure test.
- Scenario 2 - MAOP testing on all pipe, all class locations, not pressure tested to at least 1.1 times MAOP or having no documented pressure test.
• Scenario 3 - MAOP testing on all pipe in Class 3, 4 and HCA locations, not pressure tested to at least 1.25 times MAOP or having no documented pressure test.

• Scenario 4 - MAOP testing on all pipe in Class 3, 4 and HCA locations, not pressure tested to at least 1.1 times MAOP or having no documented pressure test.

5.6.4. Cost Scenario 1

Scenario 1 considers costs for MAOP testing for the 56 AGA member companies with a pressure test less than 1.25 times MAOP or no documented pressure test (all class locations). Using the weighted average cost data presented in Table 4 and Table 5, regional and national costs were developed to perform MAOP testing on pipe in all class locations that have not been pressure tested to at least 1.25 times MAOP or that have no documented pressure test.

The cost projection assumes:

- 31% of pipe that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.

- The remaining 69% of pipe that can be removed from service is hydrotested.

The cost projections, shown in Figure 17, indicate that it will cost the 56 AGA reporting companies $24.71 billion to hydrotest and/or replace the projected 17,778 miles of pipe in their systems that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.

5.6.5. Cost Scenario 2

Scenario 2 considers costs associated with MAOP confirmation for 56 AGA member companies with a pressure test less than 1.1 times MAOP or no documented pressure test (all class locations). This scenario requires a new “weighted average”
since, as discussed in Section 3.5, a higher proportion, 21.6%, in this pressure test range is in a Class 3, 4 and HCA location. The weighted averages used for the cost projections in this scenario, normalized to the central region (cost factor 1.0) are shown in Table 6.

The cost projection assumes:

- 42% of pipe that has been pressure test to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 58% of pipe that can be removed from service is hydrotested.
### Table 6: Weighted Average Values for MAOP Confirmation Costs – Scenario 2

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>Hydrostatic Test Weighted Average ($/Mile)</th>
<th>Pipe Replacement Weighted Average ($/Mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6&quot;</td>
<td>363,100</td>
<td>531,900</td>
</tr>
<tr>
<td>6/8&quot;</td>
<td>459,200</td>
<td>1,238,400</td>
</tr>
<tr>
<td>10/12/14&quot;</td>
<td>463,500</td>
<td>1,489,500</td>
</tr>
<tr>
<td>16/20&quot;</td>
<td>539,600</td>
<td>2,119,600</td>
</tr>
<tr>
<td>22/24&quot;</td>
<td>734,800</td>
<td>2,823,100</td>
</tr>
<tr>
<td>26/30&quot;</td>
<td>849,800</td>
<td>3,300,200</td>
</tr>
<tr>
<td>34/36/38&quot;</td>
<td>956,100</td>
<td>3,991,400</td>
</tr>
<tr>
<td>≥40&quot;</td>
<td>1,021,900</td>
<td>4,819,200</td>
</tr>
</tbody>
</table>

The cost projections, shown in **Figure 18** estimate that it will cost the 56 AGA reporting companies $23.27 billion to hydrotest and / or replace the projected 14,160 miles of pipe in their system that have not been pressure tested to 1.1 times MAOP or that have no documented pressure test.

**Figure 18: AGA Companies; all Class Locations; PT<1.1*MAOP; 42% Replacement**

### 5.6.6. Cost Scenario 3

Scenario 3 considers costs associated with MAOP confirmation for 56 AGA reporting companies with segments that have been pressure tested to less than 1.25 times MAOP or have no documented pressure test (Class 3, Class 4 and HCA only). For cost estimates in this scenario, the maximum estimated cost from **Table 4** for pressure test and **Table 5** for replacement is used since 100% of the pipe is in a Class 3, 4 or HCA location.

The cost projection assumes:
- 31% of pipe that has been pressure tested to less than 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.

- The remaining 69% of pipe that can be removed from service is hyrotested.

The cost projections, shown in Figure 19, estimate that it will cost the 56 AGA reporting companies $11.90 billion to hydrotest and / or replace the projected 3,289 miles of Class 3, 4 and HCA pipe in their systems that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.

![Figure 19: AGA Companies; Class 3, 4 and HCA; PT<1.25*MAOP; 31% Replacement](image)

### 5.6.7. Cost Scenario 4

Scenario 4 considers costs to the 56 AGA member companies where only pipe in Class 3, 4 or HCA locations that has not been pressure tested to at least 1.1 times MAOP or has no documented pressure test requires MAOP confirmation. For cost estimates in this scenario, the maximum estimated cost from Table 4 for pressure test, and Table 5 for replacement are used since 100% of the pipe is in a Class 3, 4 and HCA location.

The cost projection assumes:

- 42% of pipe that has been pressure tested to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.

- The remaining 58% of pipe that can be removed from service is hyrotested.

The cost projections, shown in Figure 20, indicate that it will cost the 56 AGA reporting companies $11.21 billion to hydrotest and / or replace the projected 3,058 miles of Class 3, 4 and HCA pipe in their system that have not been pressure tested to at least 1.1 times MAOP or have no documented pressure test.
5.6.8. **Evaluation of AGA Cost Projections**

A plot showing the distribution of miles and costs for each of the pressure test ranges and class location groupings is shown in **Figure 21** below.

Observations from this plot include:

- 18.5% of pipe with a pressure test less than a 1.25 times MAOP or no documented pressure test is in a Class 3, 4 or HCA location. This 18.5% of pipe is projected to account for nearly 50% of the overall cost to perform MAOP confirmation on all pipes without a pressure test to at least 1.25 times MAOP or no documented pressure test.

- More than 90% of the projected costs to test or replace pipe that has been pressure tested to less than 1.25 MAOP is allocated to pipe that has been pressure tested less than 1.1 times MAOP or has no documented pressure test.
5.7. Potential Costs – Intrastate Operators

Looking at the entire population of intrastate miles, potential MAOP confirmation costs rise substantially, primarily driven by the large number of miles located in the southwest region of the United States. A minimum-maximum plot that shows the potential cost ranges to hydrostatic test 69% and replace 31% of all intrastate pipe that has not been pressure tested to 1.25 times MAOP or have no documented pressure test is depicted in Figure 22. A second minimum-maximum plot demonstrating the same scenario except only for pipe in Class 3, 4 or HCA locations (18.5% of pipe) is shown in Figure 23.

The plots were created using the assumption that non-AGA intrastate companies have an equivalent proportion of pipe that has not been pressure tested to at least 1.25 times MAOP as the reporting 56 AGA companies. For this section, unless otherwise stated, all assumptions discussed in sections 5.5 and 5.6 apply. Cost estimates shown for intrastate pipelines do not include the approximately 8,800 miles of interstate pipeline operated by the 56 responding AGA member companies.

![Minimum-Maximum Plot](image_url)

Figure 22: Testing and Replacement Costs; PT<1.25*MAOP; all Class Locations
Figure 23: Testing and Replacement Costs; PT<1.25*MAOP; Class 3, 4 and HCA Locations

An escalation of costs to intrastate pipeline operator’s customers and its other stakeholders will result from the expansion of Congress’ requirements to intrastate transmission infrastructure beyond those covered by PSA 2011, increasing the estimated range of costs to industry from $6.0 to $23.0 billion to an estimated range of $32.6 to $124.4 billion.

5.7.1. Cost Scenario 5

A cost scenario for intrastate pipe was performed to project the cost of applying the assumptions used in cost scenario 1 to all approximately 108,000 intrastate miles in the United States. This cost scenario uses the weighted average cost data presented in Table 4 and Table 5 to project regional and national costs to perform MAOP confirmation on pipe in all class locations that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test.

The cost projection assumes:

- 31% of pipe that has not been pressure test to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- 69% of pipe that can be removed from service is hydrotested.

The projection uses the pipe size and regional distribution presented in Table 3, and the regional construction factors presented in Figure 12. The ratios presented for pressure test ranges, class/HCA groupings, and ability to remove pipe from service are assumed to be uniform for all regions, class locations and pipe sizes.

The cost projections, shown in Figure 24, estimate that it will cost the United States intrastate transmission pipeline operating companies $49.6 billion to hydrotest and/or replace the 36,414 miles of pipe in their system that have not been pressure tested to at least 1.25 times MAOP or have no documented pressure test.
Additional detailed cost projection scenarios are not formally presented in this paper for intrastate pipe. The cost projections were performed using the same ratios as presented previously, thus the cost relation for intrastate pipe scenarios will be similar to that shown for the 56 AGA companies. Scenarios for all US intrastate transmission lines, equivalent to scenarios 2, 3, and 4 performed for the 56 AGA reporting companies, are provided in Table 7.

5.8. **Summary of Costs**

The cost projections for the scenarios discussed in section 5.6 and 5.7 are summarized in Table 7.

These estimated costs assume:

- 31% of pipe that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 69% that has not been pressure tested to at least 1.25 times MAOP or has no documented pressure test can be removed from service and is hydrotested.
- 42% of pipe that has been pressure tested to less than 1.1 times MAOP or has no documented pressure test cannot be removed from service and is replaced.
- The remaining 58% that has been pressure tested to less than 1.1 times MAOP or has no documented pressure tested can be removed from service and is hydrotested.

All cost figures in this study are in present value and cost projections were performed using current estimated representative hydrotest and pipeline construction costs. A severe escalation in workload may cause costs to rise due to increased demand.
Table 7: Summary of Cost Projections

<table>
<thead>
<tr>
<th>Pressure Test Range(^8)</th>
<th>Class / HCA</th>
<th>AGA Member Companies(^9)</th>
<th>All US Intrastate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Scenario Number</td>
<td>Miles Requiring MAOP Testing</td>
<td>Projected Cost (000,000)</td>
</tr>
<tr>
<td>PT&lt;1.25MAOP</td>
<td>1, 2, 3, 4, HCA</td>
<td>1</td>
<td>17,778</td>
</tr>
<tr>
<td>PT&lt;1.1MAOP</td>
<td>1, 2, 3, 4, HCA</td>
<td>2</td>
<td>14,160</td>
</tr>
<tr>
<td>PT&lt;1.25MAOP</td>
<td>3, 4, HCA</td>
<td>3</td>
<td>3,289</td>
</tr>
<tr>
<td>PT&lt;1.1MAOP</td>
<td>3, 4, HCA</td>
<td>4</td>
<td>3,058</td>
</tr>
</tbody>
</table>

From this table, the following observations can be made:

- For AGA companies, the cost to complete testing under current federal legislation in Class 3, 4 and HCA locations is projected to be approximately $11.9 billion. If regulations are expanded to include pipe in all class locations, this cost could increase to $24.7 billion.

- Extrapolation to all intrastate pipelines increases costs projections from $23.0 billion to $49.6 billion respectively.

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\(^8\) Pressure test range includes pipe with no documented pressure test
\(^9\) 56 AGA member companies
6.0 BARRIERS TO IMPLEMENTING ADDITIONAL TEST REQUIREMENTS

Potential mandates for additional testing to validate MAOP or testing pipe without a post construction hydrotest will have an impact on the industry; however, until official rulemaking is released and testing plans are implemented by operators on a wider scale, the true impact remains to be seen. Based on input from AGA member companies and service providers, some of the perceived barriers to increased testing are discussed in the subparagraphs below.

6.1. Labor Resources

6.1.1. Utility Workforce

Information from the Bureau of Labor Statistics on Utility Employment Data\(^\text{10}\) shows that from 1991 to approximately 2005 the utility labor force steadily declined in number (Figure 25). Even additional regulations that went into effect during the 2000’s, such as integrity management, did not result in a significant increase in personnel levels.

![Utility Employment Data 1991 to 2012](image)

As a result, if there is a significant change in testing requirements, it is likely that work will need to be outsourced because current operator workforce levels will not be able to support current pipeline safety programs as well as additional testing requirements.

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6.1.2. **Contract Resources**

In order to better understand potential barriers contract resources may encounter as a result of increased testing requirements, surveys were sent to contract resources. The primary issues identified included:

- Project management personnel
- Training
- Qualified welders
- Qualified heavy equipment operators
- Office administrative staff
- Qualified general labor
- Heavy equipment
- Safety personnel

Additionally, the topic of the availability of contract resources was explored, with key feedback including:

- Contractors are already busy with existing workload.
- Due to current work in the state of California, some contractors that have been traditionally used for projects are not available or the price per unit has significantly increased.
- Qualified welders and experienced project management personnel and foreman are difficult to attain.
- Some operators currently are seeing higher costs but in general resources are still available; however, the majority of companies have not implemented significant MAOP testing / replacement projects.

6.2. **Permitting**

In the overall life cycle of a testing or replacement project, permitting typically has the longest duration.

6.2.1. **Testing**

Typical permits for a testing project include:

- Water acquisition.
- Water discharge.
- Temporary workspace easements.

Typical agencies that an operator may have to work with in order to obtain permits for testing projects include:

- State Environmental Protection Agency (EPA).
- Local Municipality, County, State regulatory body for use of land.
- Local, County, State department of transportation for work performed in road right-of-ways.
- Railroad company for work performed in railroad right-of-way.
- Federal Bureau of Land Management (BLM) for work performed on federal lands.
- Army Corps of Engineer for work performed in or near navigable waterways.

The type and number of temporary work space easements / permits required is dependent on the extent of the hydrostatic testing project. Temporary workspace permits are required for each location where excavations are planned, as well as locations where the test will be administered. Work space at testing locations will need to allow for the testing crew to set up equipment such as manifolds, pumps, frac tanks and hydrostatic testing trailers.

In addition to acquiring permits for temporary workspace, permits are also required to acquire water for hydrostatic testing. Typically, when available, the most cost effective water supply for hydrostatic testing is from a local river. In order to use water from a river or navigable waterway, a permit from the Army Corps of Engineers is required. In addition to federal permits, a state or other regulatory authority may also require a permit to use water from a local natural water resource. If there is not a river or other suitable natural water source available, water can be purchased from a local municipality. Permitting requirements and water acquisition costs vary by local municipality.

For a hydrostatic testing project, the most permit extensive component typically is water discharge. In order to discharge water onto the ground or to a natural water source, permits are required from the state EPA. If water is to be returned to a navigable waterway or river, a federal permit from the Army Corps of Engineering is also required. State environmental permits typically specify that the water intended for discharge be tested for constituents including, but not limited to, total oil and grease, pH, total chlorine, benzene, and toluene. The acceptance levels for each of the tests are state EPA specific. If the water to be discharged is not within the specified level, typically filtering is required prior to discharge. The filtering operation is an additional project cost.

In some cases, water may be discharged into a local municipality sewer system. This option has a high cost premium; however, there are less environmental restrictions and permits required.

The permitting process for a hydrostatic test project could take as little as thirty (30) to sixty (60) days for a project with minimal scope of work in an area with less restrictive environmental requirements. A project in an area with strenuous environmental requirements or other burdensome restrictions could take greater than six (6) months.
6.2.2. Replacement

The permit requirements for pipe replacement projects include all requirements of a hydrostatic testing project with additional land acquisition, land use, and environmental / wetland permitting requirements. The permitting process for a pipeline replacement project could take as little as thirty (30) to sixty (60) days for a short project in an area with low environmental impact, a small number of road crossings, and no waterway crossings. A project in an area with strenuous environmental requirements or other burdensome restrictions could take one (1) or more years. Typical permits that are required on a pipeline replacement project include:

- Right-of-way acquisition.
- Temporary workspace easements.
- Road crossings.
- Railroad crossings.
- Navigable waterway / other water body crossings.
- Wetland delineation / permits.
- Threatened and endangered species preservation permits.
- Hydrostatic test water acquisition.
- Hydrostatic test water discharge.

Typical agencies that an operator may have to work with in order to obtain permits for replacement projects include:

- State and Federal EPA.
- Local Municipality, County, State regulatory body for use of land.
- Local, County, State department of transportation work performed in road right-of-ways.
- Railroad Company for work performed in railroad right-of-way.
- Federal Bureau of Land Management (BLM) for work performed on federal lands.
- Army Corps of Engineer for work performed in or near navigable waterways.

6.3. Testing Failures

The occurrence of failures during a testing project can be unpredictable, with the frequency of failures during hydrostatic testing dependent on the integrity of the pipe and the quality of the pipe manufacture. Pressure test failure rates are not homogenous across testing projects and often occur in clusters at locations of subpar coating, aggressive environmental conditions, and/or pipe of common manufacturer production run. The variability in failure occurrence makes it difficult to predict the number of failures that will occur during a
testing project. Testing failures add significant costs to a project and can considerably affect the construction timeline, lengthening the duration that the pipeline section is out of service. To mitigate this risk, some operators may choose to perform ILI runs where feasible prior to commencing a pressure test and initiating repairs in areas of indications as appropriate to alleviate failures during the test.

6.4. **Design Considerations**

The existing configuration of a pipeline has a substantial effect on the scope, duration, and cost of a hydrostatic testing project for an in-service transmission pipeline. During project planning, a system design review must be performed to identify any component that will require replacement in order to complete a successful hydrostatic test project. All components in the pipeline must have a full diameter opening so that cleaning, fill, dewater, and drying pigs can pass through the system. Some connection openings (i.e. branch, tee, stopple fitting, etc.) may need to be barred to ensure that pigs do not become trapped or lost. Internal connections (i.e. internal drips, etc.) that could impede the passage of a pig should be removed.

Any modifications and repairs that have been made to the pipeline during maintenance should also be reviewed during project planning. At increased testing pressures, certain modifications, such as leak clamps and stopple fittings, may be susceptible to leaks or rupture during testing.

The following pipeline components typically are flagged for replacement or additional review during hydrostatic test planning:

- Reduced port valves (reduced bore ball valves, plug valves, etc.).
- Unbarred tees, branches, or other connection.
- Stopple fittings and other line stop installations.
- Internal connections including internal drips.
- Pipeline repairs (leak clamps, type A sleeve, type B sleeve, etc.).

If the existence and/or location of a restrictive component is unknown, it could result in a difficult to locate leak or an obstructed cleaning/drying pig. This type of event could cause significant project delays, lengthen the amount of time the pipeline is out of service, and increase project costs.

Test section length is also dependent on the design of the pipeline. A pipeline with diameter changes may need to be tested in multiple sections depending on multi-diameter size pig availability and capabilities.

6.5. **Outage Management**

For pipelines with single source and/or peak customers for whom the operator's system will be unable to supply gas, or an adequate amount of gas, while the section of pipeline to be tested is out of service, the operating company may need to provide a temporary gas supply. The temporary gas supply method employed will vary depending on the number of customers affected, the quantity of gas required, and the expected length of time that a
pipeline is out of service. For a limited number of residential customers, a frequently used method to supply gas is compressed natural gas (CNG) or liquefied natural gas (LNG) bottles. If a large gas supply is required, the use of one or more LNG tankers is typically the most effective solution. In some cases, the logistics and cost of outage management solutions can be a detriment to the testing alternative.

6.6. **System Configuration**

AGA member operators have a significant percentage of their transmission lines functionally intertwined with their distribution systems. These transmission lines are both geographically and operationally influenced by the locale and operational characteristics of the supplied distribution systems.

Stemming from the distribution system “influence” on their transmission infrastructures, the ability to run pigs for hydrostatic testing of these lines is markedly limited for AGA member operators. As seen in Section 3.7, greater than 60% of the AGA member survey transmission assets, regardless of the class location, are not ILI-able, thus likely would require capital outlay to convert them to allow the passing of a drying/cleaning pig. For the significant percentage of the non-piggable miles, especially in Class 3 or 4 locations, this capital outlay may make replacement of these lines more cost effective than testing to confirm MAOP.

Single source feeds to large volume customers or to distribution load centers is a primary driver toward the escalation of costs of MAOP testing plans for AGA member companies. Given limited ability to provide temporary gas supply to these loads, lines with this characteristic may require the more costly alternative of pipe replacement.

Some transmission networks which feed distribution systems are configured such that pressure sub-systems within the transmission network cannot have pressure lowered in just the immediate area of the MAOP testing work. Isolation of the work area is not possible without affecting supplied area loads which need to be maintained. This situation precludes less expensive testing, requiring replacement with commensurate elevated costs, or engineering and construction of additional distribution supply regulator stations.

Intrastate Class 1 or Class 2 lines supplying transmission networks feeding distribution systems may not be looped nor have multiple take points from interstate lines. These lines may require loop, supply tap, or bypass construction to make testing feasible or may even require pressure deration with parallel line construction.

6.7. **Testing and Construction Season**

Weather and climate constraints are the primary limitations on the construction season. In addition to weather considerations, hydrostatic test projects require the pipeline to be removed from service and are affected by operational system constraints. Due to load requirements in the winter heating and summer cooling months, pipeline hydrostatic testing construction scheduling has gradually concentrated on the spring and fall season “shoulder months”. The effect climate and operational capacity requirements have on the construction season will vary by operating company. Limits on the construction season may lengthen the implementation duration of operators’ MAOP testing plans, and/or affect costs associated with implementation.
As mentioned earlier in this report, testing and replacement project durations are affected by right-of-way acquisition, test medium procurement (i.e. water), and both construction and environmental permitting bottlenecks. Their impacts will be compounded by the activity window limitations.

Jurisdictional moratoria on construction (i.e. due to new and recently reconstructed pavement) also affect the duration of testing and replacement projects. These impacts are also compounded by the activity window limitations due to weather and operational capacity considerations. The limited time window to perform hydrostatic testing projects may compel an operator to opt for replacement. Ramp-up in construction during shoulder months may result in contractor resource availability constraints further driving cost escalation.

6.8. **Drying the Line**

Following a successful hydrostatic test, the pipeline is typically dewatered into frac tanks or directly into an adjacent test section. The pipeline is next dried by running polyurethane and foam pigs through the system. A typical standard is to run foam pigs through the pipeline until they are dry within 1/4-inch of the surface. After drying with the foam pigs many companies require compressed air to be run through the pipeline until a -38°F dew point is held for a specified length of time.

In areas with elevation changes, extra effort may be required to ensure that all water is removed from the pipeline since water that pools in low spots increases the internal corrosion risk. Extra effort could include contracting a drying crew that uses nitrogen, methanol, desiccant dryers, etc. to ensure the pipeline is dry.

Work space needs for hydrotest equipment can be sizable, particularly for frac tanks which have large footprints. Elevation changes and the extra effort described for drying the line will result in extended project durations. These space and time factors will shorten the length of line that can be hydrotested at a single process, specifically in congested Class 3 or Class 4 areas, resulting in cost escalation for hydrotests in these locations.

6.9. **Additional Barriers**

6.9.1. **General Public**

Ratepayer advocacy groups objecting to the higher cost alternative of pipe replacement could delay or otherwise hamper execution of this alternative. Similarly, public concerns could also detrimentally affect the execution of either testing or replacement construction plans. Right-of-way acquisitions and approvals are influenced by these factors. In some instances, ratepayer advocacy may be proponents for additional (unnecessary) testing. Public relations and community outreach efforts will need to be expended to mitigate these concerns for a subgroup or full constituency of stakeholders.

6.9.2. **Site Specific Requirements**

Specific requirements at crossings (i.e. river canal, road crossings) beyond permitting typically include additional burdens, such as added depth of installation,
use of the Horizontal Directional Drilling (HDD) installation process, heavier pipe wall thickness, abrasion resistant coatings, and casing pipe requirements. These factors may add to the costs of a replacement project.

For jurisdictional specific cases, requirements to remove abandoned pipe from the rights-of-way may add additional costs to the project.

6.9.3. **Urban Development**

Population related development in the immediate proximity of pipeline rights-of-way may limit the availability of line-of-lay for replacement projects. Inability to reach agreements with other providers who use the ROW to temporarily take their lines out of service will impair this alternative, as well as the inability to take the current gas transmission line out of service to prevent an incident occurrence from accidental line impingement during construction in lines-of-lay in close proximity to these existing facilities. These issues may arise even in Class 1 and 2 locations if landowners refuse to grant additional ROW in areas of facilities congestion.

6.9.4. **Availability of Materials**

If the industry mobilizes a large number of replacement projects in a short time frame, the availability of materials for infrastructure, such as line pipe and valves, may become limited. Some operators may resort to standardization to a single strength and wall thickness per diameter so flexibility is enabled to move from project to project, arguments as to overdesign notwithstanding. Difficulties with obtaining valves due to very long lead time have already been experienced by some operators.
7.0 OTHER OPTIONS AND CONSIDERATIONS

7.1. General Discussion

Economic factors will influence an operator's choice from amongst the prescribed alternatives for MAOP testing. These alternatives: testing, replacement, and pressure reduction, are equally effective for reestablishing MAOP. However, the economics of logistics, infrastructure materials, design, system configuration, skilled pipeline industry labor market, and shortened construction timeframes will be unique to each operator. Adding to the non-uniform landscape of operator analysis will be ratepayer advocacy, other potential political pressures, and jurisdiction-specific requirements.

For MAOP testing on some pipeline sections, traditional capitalization may prove to be the fiscally prudent path, while for others, absorption of O&M costs may instead provide the best cost path.

From a review of Pipeline Safety Enhancement Plans (PSEP) filed to the California Public Utilities Commission, the three major intrastate transmission line operators were faced with unique factors in their decision processes that resulted in different approaches and action plans to respond to the CPUC mandates. Review also suggests that given the wide variation in system constraints and other factors to which other intrastate and LDC transmission line operators are exposed, differences in strategies and action plans for operators across the country will be necessary.

7.1.1. Aggregate U.S. Operator Implementation

As noted in Section 5.8, a five-fold increase in the number of miles requiring testing results from the inclusion of Class 1 and Class 2 non-HCA lines.

87% of lines included in PSA 2011’s requirements for review of records for MAOP verification have been found to meet TVC records criteria by LDC and intrastate transmission line operators. Thus, under current regulation, 3% of U.S. intrastate lines will require some type of additional MAOP confirmation efforts. With rulemaking changes to require increased testing, the percentage increases eleven-fold to 34%. This results from the significant increase in the number of miles that would become subject to MAOP testing if regulations require testing in all class locations that have not been tested up to 1.25 times MAOP or have no documented pressure test.

7.1.2. Operator Plan Schedules and Impacts on Customers

Strained industry resources may result in extended aggregate implementation of MAOP testing and replacement efforts. This effect may be offset somewhat by service provider ramp-up driven by greater returns from cost escalation, but no data to quantify the predicted effect is available at this time.

Strained industry resources may also delay construction for large volume load additions, potentially constraining commercial/industrial customer productivity.
7.1.3. **Environmental and Other External Constraints**

The actions associated with overcoming the barriers discussed in Sections 6.2 through 6.9 will expand in conjunction with the miles of transmission pipelines to which regulations are imposed.

7.1.4. **Resource Availability**

Price elasticity to labor demand may be at high sensitivity, given the current status of availability of skilled labor for natural gas systems. There are indications that the collective cost is already higher due to the California experience.

7.2. **Potential Subpart O Conflicts**

MAOP testing activities may affect an operator's implementation of the risk assessment, remedial actions, and the performance measurement aspects of an operator's Transmission Integrity Management (TIMP) plan, as required by 49 CFR Part 192 Subpart O. An operator's TIMP risk-based prioritization of assessments and remedial actions may be impacted on an ongoing basis as MAOP testing program work continues, with the required periodic assessments and data analysis being complicated by or conflicting with actions and data stemming from MAOP testing or replacement projects.
8.0 CONCLUSIONS

While the specific relationships of scope and costs are difficult to assess, the expansion of regulations in the state of California has resulted in additional costs resulting from increased testing and replacement. Expansion of regulations will have a considerable effect to the industry, with actual costs driven by the specific testing and timeline mandates implemented by PHMSA and state jurisdictional authorities.

Testing is logistically complex and usually requires some redesign and reconfiguration of the system. In some cases, replacement may be a viable alternative to testing, and may be the only alternative for pipes that cannot be removed from service. Lowering pressure is another viable option; however, resulting capacity restrictions may require construction of substantial additional infrastructure.

Timelines for implementing testing and replacement projects are protracted as a result of permitting requirements, which typically are the longest duration component to a project. In addition, seasonal constraints limit the timeframe in which work can be completed.

The projected costs to test or replace pipe in Class 1 and 2 non-HCA locations is substantial, with cost recovery mechanisms being different for testing versus replacement. Given the magnitude of potential cost compared to current capital and operations spending, MAOP testing and replacement programs may need to be spread out over an extended period of time, varying from years to decades depending upon operator-specific economics and pipeline networks.

Potential MAOP testing requirements will result in markedly significant impacts in terms of outage management, resource availability and system configuration. Additionally, skilled resources and aggressive schedules will impact costs as demonstrated by the California experience. A carte blanche application, across all operators, of a standardized method for MAOP testing cannot feasibly be implemented by operators. Operators will need to work individually with each of their state’s regulators to determine the feasible plan for each affected pipeline, and engineering prioritization studies (like those performed by the California companies) may need to be performed individually for each operator in order to facilitate discussions with state regulators and to facilitate implementation of future mandates.