Dynamic Risk

Date	February 4, 2020
From	Patrick H. Vieth Dynamic Risk
RE:	**Statewide Assessment of Gas Pipeline Safety** **Commonwealth of Massachusetts**

Presented herein is our Final Report related to the above referenced project. As noted in the Revision Log, this Final Report amends Appendix C.11 which was inadvertently omitted.

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Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts

Commissioned by the Massachusetts Department of Public Utilities

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Executive Summary

Introduction

In November 2018, the Massachusetts Department of Public Utilities (DPU) selected and contracted with Dynamic Risk Assessment Systems, Inc. (Dynamic Risk) to conduct an independent statewide examination of the safety of the Commonwealth's natural gas distribution system (Assessment). This *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts* Final Report encompasses the final work product of this Assessment. It builds on, and replaces in its entirety, the *Phase 1 Summary Report*, dated May 13, 2019 (the *Phase 1 Report*). This executive summary provides a high-level summary of the principal areas covered in the Final Report, including:

- The Scope of this Assessment;
- The Panel;
- The Guiding Principles;
- Perspectives Considered;
- Work Performed;
- Observations;
- Recommendations; and
- Conclusions.

Further details on each topic are in the body of the Final Report (Sections 1 to 12).

Scope of this Assessment

This Assessment, conducted in Phase 1 and Phase 2 by the Independent Review Panel (the Panel), evaluated the physical integrity and safety of the Commonwealth's gas distribution systems operated by the seven investor-owned gas distribution companies and four municipal gas companies (collectively, the Gas Companies) and the operations and maintenance policies, practices, and execution by the Gas Companies. The Panel also offers observations developed during this Assessment regarding various organizations involved in pipeline safety within the Commonwealth, such as the DPU, the Attorney General's Office (AG Office), and other Interested Parties.

About Massachusetts Gas Pipelines

The Gas Companies in Massachusetts operate approximately 21,000 miles of pipelines (mains) and over 1.3 million services. The mains operated in Massachusetts represent approximately 2% of the mains operating in the United States. These mains represent a disproportionately higher percentage (7%) of the leak prone mains operating in the United States and have a leak ratio that is 4 times that of the national average. For these reasons, Massachusetts initiated the Gas System Enhancement Plan (GSEP) that provided a mechanism for Gas Companies to receive accelerated rate recovery for the replacement of the leak prone infrastructure over time.

As discussed further in this Final Report, there are certain risks associated with the continued operation of leak prone pipe, and there are also certain risks associated with the complex replacement of the mains and services. Gas pipeline safety is a function of both the safe operation of these systems and the pace and prioritization for which the leak prone mains and services are replaced.

The Panel

Dynamic Risk assembled an Independent Review Panel (the Panel) comprised of recognized experts with diverse professional experience. The Panel and the Project Technical Support Team (Project Team), which is comprised of well-qualified technical experts, bring unique experience, expertise, and perspectives to this project. Panel and project team names and information are set forth in Appendix D.1 and Appendix D.2, respectively.

Guiding Principles

The principles guiding the Panel in conducting this Assessment are independence, accuracy, and transparency. The Panel relied upon the facts derived during Phase 1 and 2 to develop its observations, findings, and recommendations. Inherent in this approach is the Panel's neutrality relative to the desire of any particular group and/or to any specific outcome.

The primary goal for the Panel in conducting this Assessment is to provide recommendations that, if implemented, will enhance the safety of the natural gas pipeline distribution systems in the Commonwealth.

Perspectives Considered

The Panel relied upon the contributions of various parties. Each brought a unique perspective to this Assessment. The parties that contributed to this Assessment, or that bring a perspective considered by the Panel, include the following:

- Project Team. Dynamic Risk staff and contractors who provided technical support and resources;
- DPU and EEA Project Managers. Executive Office of Energy and Environmental Affairs (EEA) and the Department of Public Utilities (DPU) provided Project Managers who provided oversight and are actively engaged to support the Panel and Project Team to meet the objectives;
- DPU personnel. Individuals from the DPU office supporting pipeline safety and rate cases who the Panel interviewed;
- Gas Companies. Leadership, staff, and contractors from each of the 11 Gas Companies;
- Stakeholder Groups. The three Stakeholder Groups included the Elected Officials Group (see Appendix D.5.1), Community Representatives Group (see Appendix D.5.2), and the Industry Representatives Group (see Appendix D.5.3). These groups provided perspectives to the Panel through three listening sessions; and
- Interested Parties. Individuals and organizations that can affect gas pipeline safety include State Legislators, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA), the DPU, Massachusetts AG Office's Ratepayer Advocate, Unions working at Gas Companies, Environmentalists, Ratepayers, and Municipal Governments.

The Panel formally recognizes and offers its appreciation for the candid participation of the Stakeholder Groups, Gas Companies, and individuals at the Massachusetts government agencies that contributed to this Assessment. The Panel considered input from each group throughout this assessment. However, the Panel is solely responsible for the assessments, observations, and recommendations set forth in this Final Report.

Work Performed

In Phase 1, the Panel conducted a program level assessment and evaluation of each Gas Company, and an initial assessment of the programs' effectiveness. This was largely performed through initial meetings with the senior leadership teams of the Gas Companies, interviews with the DPU personnel, reviews of documents produced by the DPU and the Gas Companies, listening sessions with Stakeholder Groups, and individual meetings with the Gas Companies. It also included a review of assessments and inspections performed by others, such as third-party audits by outside experts or insurance companies, and researching and analyzing laws, regulations, data, and other materials.

Phase 2 focused on field visits to enable the Panel to observe work execution by the Gas Companies. The Panel visited over 150 different field sites and spent over 25 days in the field, working an estimated 57-person days in the field. The length of the visit and the number of construction sites visited at each Gas Company varied, depending upon Gas Company size, number of operating areas, and the amount and variety of projects underway during the Panel's visit. The Panel spent enough time with each Gas Company to develop sufficient confidence in the observations to make recommendations set forth in this Final Report. The Panel also conducted interviews with the DPU, conducted a listening session with Stakeholders, and reviewed additional documents collected from the Gas Companies and DPU.

Observations and Recommendations

The observations developed by the Panel are grouped within this Final Report as follows:

- Safety culture (Section 7);
- Massachusetts Gas System Assets (Section 8);
- Gas Companies, in general (Section 9);
- Individual Gas Companies in the Gas Company Snapshots in Appendix B;
- Beyond the Gas Companies (Section 10);
- Best Practices (Section 11); and
- Recommendations (Section 12).

Conclusions

This Assessment has been undertaken to assess the current condition of the gas infrastructure and to assess the programs and practices used to manage the gas mains and services operating in Massachusetts. Massachusetts' natural gas distribution pipeline systems contain a disproportionately higher percentage of leak prone mains when compared to the national average. The Gas Companies are currently replacing leak prone pipe infrastructure at a pace to meet a 20-year goal as part of the legislatively-approved Gas Safety Enhancement Program, but the continued presence of leak prone pipe in the gas systems present certain operational risks to the public. While the replacement of the leak prone pipe reduces future operational risks, the process of replacing the leak prone pipe has certain associated risks and barriers. Addressing and reducing these risks and barriers requires collaboration amongst all stakeholders.

Within this Assessment, the Panel evaluated the programs and practices used for operations, maintenance, and construction of the gas mains and services. To that end, each Gas Company was evaluated against the infrastructure that they managed. For example, the relatively small Gas Companies do not maintain sufficient expertise and capacity to manage the larger complex systems. While certain practices are common amongst all Gas Companies, each is unique in its own way and each has an opportunity to improve. Gas Companies that maintain or increase the pace of replacement require not only improvements in execution, but also the need to advance and embrace a safety culture of learning and continuous improvement.

The observations and recommendations developed during this Assessment and presented in this Final Report provide opportunities for all Stakeholders to enhance pipeline safety. This Final Report also provides awareness of certain challenges arising from organizational goal conflicts. These observations identify roles and opportunities for all Stakeholders to adopt a collaborative approach to enhance pipeline safety throughout the Commonwealth. While the Gas Companies are ultimately responsible for gas pipeline safety, pipeline safety can only be achieved by working together – with all involved embracing the common goal of enhancing pipeline safety across the Commonwealth.

The recommendations provided herein reinforce certain programs, highlight opportunities, and serve as a roadmap for continuous improvement.

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1 Introduction

In November 2018, the Massachusetts Department of Public Utilities (DPU) selected and contracted with Dynamic Risk Assessment Systems, Inc. (Dynamic Risk) to conduct an independent statewide examination of the safety of the Commonwealth's natural gas distribution system (Assessment).[1] The Commonwealth asked that this Assessment be completed in two phases and represent a comprehensive and technical safety review resulting in recommendations for improvement.

This *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts Final Report* or Final Report encompasses the final work product of this Assessment. It builds on, and replaces in its entirety, the *Phase 1 Summary Report*, dated May 13, 2019 (the *Phase 1 Report*).[2]

1 Through authority granted by Governor Baker under a State of Emergency declared on September 14, 2018, the DPU's Chair directed that the natural gas distribution companies operating in the Commonwealth cooperate with and pay for this Assessment.

2 The *Phase 1 Summary Report* is available at the DPU's website: https://www.mass.gov/orgs/pipeline-safety-division

2 Background

2.1 Scope of this Assessment

This Assessment, conducted in Phase 1 and Phase 2 by the Independent Review Panel (the Panel), evaluated the physical integrity and safety of the Commonwealth's gas distribution systems operated by the seven investor-owned gas distribution companies and four municipal gas companies (collectively, the Gas Companies),[3] and the operations and maintenance policies and practices of the Gas Companies.[4]

While not limited to these topics, the six main focus areas for assessing the Gas Companies (see Figure 1) include:

1. Pipeline safety management systems;
2. Risk management programs or practices;
3. Integrity management programs;
4. Operations and maintenance (O&M) procedures and practices;
5. Construction procedures and practices; and
6. Incident/crisis management.

Figure 1: Assessment Main Focus Areas

The Panel also evaluated the effectiveness of organizations, programs, and processes being employed and executed by the Gas Companies. In addition, the DPU initially provided a list of questions that the Panel addressed during this Assessment.[5] Of these questions:

- Four focused on the physical integrity of the gas distribution assets and inspections; and
- Eight focused on the programs and processes used by the Gas Companies.

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[3] Appendix D.4 contains a list of the 11 Gas Companies included in this Assessment. Throughout the Final Report, companies are referred to by name or by one of the three-letter designations set forth in Appendix D.4.

[4] This Assessment is separate from the investigation led by the National Transportation Safety Board, which is focused on the September 13, 2018 gas incident in the Merrimack Valley region and its potential causes.

[5] See Appendix E, DPU Initial Questions for Assessment.

In conducting this Assessment, the Panel developed findings and observations – which in turn – enabled the Panel to make final recommendations for action. The Panel's findings and observations about:

- Safety Culture are set forth in Section 7;
- Massachusetts' natural gas pipeline assets are set forth in Section 8;
- The Gas Companies, in general, are set forth in Section 9;
- Each Gas Company, individually, are set forth in the Gas Company Snapshots[6] in Appendix B;[7]
- State Agencies involved in pipeline safety within the Commonwealth, including the DPU, the Attorney General's (AG) Office, and the Department of Energy Resources (DOER), and Interested Parties[8] are set forth in Section 10; and
- A list of Best Practices[9] are set forth in Section 11. Recommendations are set forth in Section 12.

The Panel also worked in collaboration with safety culture experts to develop a *Safety Culture White Paper* (*White Paper*) – see Appendix A.

2.2 The Panel

Dynamic Risk assembled an Independent Review Panel (the Panel) comprised of recognized experts with diverse professional experience for the successful and timely project execution. This Panel and the project team, which is comprised of well-qualified technical experts, bring unique experience, expertise and perspectives to this project. Panel and project team names and information are set forth in Appendix D.1 and Appendix D.2, respectively.

2.3 Phase 1 and Phase 2

To meet the milestones set by the Commonwealth, this Assessment was conducted in two phases.

Phase 1, which was the subject of the *Phase 1 Report*, included a program-level assessment and evaluation of each Gas Company. This was largely performed through initial meetings with the Gas Companies, interviews with the DPU personnel, initial document requests to the DPU and the Gas

6 Recognizing this Assessment records observations from the then-current state of the Gas Companies, the Panel elected to use Gas Company Snapshots (see Appendix B) instead of a scorecard or a dashboard, which are often used by businesses to track and report on a company's strategic or tactical performance. The Snapshots contain for each Gas Company a system overview, information on the field visits, observations on strengths and opportunities, and bullet points derived from a review of a company's procedures and programs as derived from a review of the documents and the Gas Company presentations to the Panel.

7 In early January 2020, the Panel engaged in a Snapshot Review Process with the Gas Companies, the DPU, the AG Office and the labor members of the Community Stakeholder Group. The Snapshot Review Process is described in more detail in Appendix C.

8 The role of Stakeholders and Interested Parties is expanded upon in Sections 3 and 4 of this Final Report.

9 The phrase *Best Practices* describes a method or technique that, in the Panel's experience, has been generally accepted in the industry as being superior to alternatives because it produces results that enhance pipeline safety. The Panel's use of the phrase is not intended to suggest that there is only one correct way to perform the work; instead, it is meant to indicate that the practice is a leading best practice within the industry. Best practices or leading best practices should continue to be developed over time based on organizational learnings.

Companies, review of the documents provided (as necessary), listening sessions with Stakeholders, and individual meetings with the Gas Companies for extensive discussions.[10]

In Phase 2, the Panel broadened the inquiry. Building on the work performed in Phase 1, the Panel utilized field assessments, gathered additional data from the Gas Companies and the DPU, and further deepened its data analyses, including data maintained by PHMSA.

The field assessments involved observing the Gas Companies performing maintenance, construction, and service work, conducting informal field personnel interviews, and visiting facilities such as operations centers, gate stations, district regulator sites, and, where relevant, gas control centers.[11] The Panel also continued to develop observations concerning the State Agencies and Interested Parties involved in pipeline safety within the Commonwealth.

2.4 The Panel's Guiding Principles

The principles guiding the Panel in conducting this Assessment are independence, accuracy, and transparency. The primary goals of the Panel in conducting this Assessment are to identify opportunities to improve the safety of the natural gas pipeline distribution systems in the Commonwealth and provide recommendations that, if implemented, will advance that goal.

The Panel committed to following the facts derived during the Phase 1 and Phase 2 work to develop its observations, findings, and recommendations. Inherent in this approach is the Panel's neutrality relative to the desire of any group, specific outcome, or both.

2.5 Context for the Final Report

This Final Report includes the culmination of work performed in Phase 1 and Phase 2. The statements, observations, and recommendations in this Final Report:

- Should be read in the full context of the Final Report; and
- Are based upon the current state as observed.

The Panel received the full support of the DPU when conducting this Assessment. The Panel was empowered to explore various aspects of pipeline safety, within the DPU itself and in other government agencies, as it deemed appropriate. Likewise, the Gas Companies, Stakeholders and other Interested Parties willingly invested their time to answer questions, provide insights, and support the effort. The Panel appreciates this support and cooperation.

[10] Phase 1 work also included a review of assessments and inspections of the Gas Companies performed by others, such as third-party audits by outside experts or insurance companies, and researching and analyzing laws, regulations, data, and other materials.

[11] The Panel also opportunistically visited Gas Companies' LNG facilities to better understand the role of LNG in meeting gas supply demands for a given system. An audit or review of the status, integrity, or operation of LNG facilities, however, is outside the scope of this Assessment.

3 Work Performed

3.1 Phase 1

The Panel commenced this Assessment in November 2018. A critical part of this initial phase was the development of the appropriate Guidelines for Engagement with the DPU, Gas Companies and Stakeholder Groups. These guidelines help facilitate the process, provide transparency, and protect the independence of the Panel during the Assessment. The guidelines, which set out the Panel's expectations and proposed boundaries, including the handling of potentially sensitive information, as between the Panel and each of these groups, and between each of the groups, were discussed with the relevant parties and subsequently provided to them.

Among other topics, the Guidelines stated that discussions held as part of this Assessment would be conducted under Chatham House Rules. These are rules of engagement in which participants in a meeting, including Panel members, are free to use the information received; however, neither the identity nor the affiliation of the speaker(s), nor that of any other participant, may be revealed. Chatham House Rules are often used in settings in which candid and open discussion by participants is required. Moreover, while Chatham House Rules allow information provided in any presentation or discussion to be shared with others outside the group, the Panel also encouraged all participants to exercise discretion in sharing the information learned during this Assessment to preserve the integrity of this Assessment and ensure that information and results are provided in full context.

Other work completed in 2018 included:

- Interviewing select personnel at the DPU;
- Developing and issuing an information request to the DPU;
- Leading videoconferencing calls with executives and teams from each of the 11 Gas Companies to:
    - Initiate the project;
    - Make introductions;
    - Discuss proposed Guidelines; and
    - Establish dates on which the Gas Companies would meet:
        - In person with the Panel for a discussion; and
        - For a presentation by the Gas Companies to the Panel.
- Developing an information request to the Gas Companies for documents in these 17 categories of interest:
    - Organizational structure;
    - Leadership;
    - System overviews;
    - Asset management;
    - Plans and procedures for distribution integrity management;
    - Pipeline risk management;

  - Pipeline Safety Management System plans, if any;
  - Emergency Response (ER) plans;
  - Construction processes;
  - O&M manuals;
  - Leak history information;
  - Reportable incidents;
  - Dig Safe data;
  - Enforcement actions by the DPU;
  - Audit reports (internal and external);
  - Rate case history; and
  - Work force demographics and records.
- Developing the Assessment Work Plan for Phase 1 to set out timelines and plans for conducting Phase 1; and
- Providing the Gas Companies with the Information Request, Guidelines for Engagement, and the Work Plan.

In early January 2019, the DPU and each of the Gas Companies uploaded documents responsive to the information requests each had received in December. Collectively these responses totaled tens of thousands of pages.[12]

In addition, work completed in January 2019 included:

- Establishing the members of each Stakeholder Group and sharing the Guidelines with participants;
- Participating in the first listening session with each Stakeholder Group;
- Developing a detailed list of topics for discussion at meetings with each individual Gas Company and providing those topics to each Gas Company the week before their scheduled presentation; and
- Meeting with several individual Gas Companies. Meetings began at 8 a.m., included a lunch break, and typically ended at 4 p.m. Several Gas Companies elected to meet for an additional half day.

In February, March, and April 2019, work that was performed included:

- Completing the meetings between the Panel and remaining individual Gas Companies;
- Reviewing PHMSA incident and asset data for the US, the Northeast,[13] and Massachusetts;

[12] The Panel began the review and assessment of these documents in Phase 1 and completed it in Phase 2. The purpose of the review was to further understand the Gas Companies' processes and procedures, and complexity of provided documents. Because of resource constraints and the volume of provided Gas Company documents, the Panel focused its review on a select portion of the provided documents.

- Continuing review and analysis of materials produced in response to information requests and other relevant information;
- Participating in the second listening sessions with each of the three Stakeholder Groups on March 11 and 12, 2019. Stakeholders were invited to attend this listening session in person. Some Stakeholders participated via videoconferencing; and
- Providing a verbal presentation to the DPU and EEA on March 14, 2019 to discuss work to date and next steps to produce a Phase 1 summary report.

In mid-May, the Panel provided the *Phase 1 Report* to the DPU and Stakeholders, which was made available to the public on the DPU's website.[14]

3.2 Phase 2

Phase 2 of the Assessment began shortly after the *Phase 1 Report* was completed with meetings between the Panel, Stakeholders, and Interested Parties at the end of May. The Panel also issued two information requests. One request was made to selected Gas Companies to gather a sampling of construction planning documents to assist the Panel in scheduling Field Visits. The second information request was issued to Columbia Gas of Massachusetts seeking information about an overpressure incident on May 6, 2019 in Zanesville, Ohio on the gas distribution system operated by Columbia Gas of Ohio.[15]

The Panel also conducted additional interviews with the DPU Commissioners and personnel about its processes and prior inspections of the Gas Companies. The Panel also met with DOER to discuss DOER's role and input into pipeline safety.

As Phase 2 progressed, the work fell largely into two categories: Field Visits and Other Workstreams. These are described in sections 3.2.1 and 3.2.2.

3.2.1 Field Visits

The Panel initiated field visits to each of the Gas Companies in late July 2018 and completed them in early November 2018. The Panel spent enough time with each Gas Company to develop sufficient confidence in the observations to make recommendations set forth below.[16] The length of the visit

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13 The states considered to be in the Northeast are those represented by the Northeast Gas Association (NGA). NGA represents natural gas distribution companies, transmission companies, liquefied natural gas importers, and associate member companies. These companies provide natural gas to over 12 million customers in nine states (Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island and Vermont). NGA was established on January 1, 2003. Its predecessor organizations were The New England Gas Association (founded in 1926) and the New York Gas Group (founded in 1973). (https://www.northeastgas.org/about_intro.php).

14 The *Phase 1 Summary Report* is available at the DPU's website: https://www.mass.gov/orgs/pipeline-safety-division

15 See Appendix B.3.3, Columbia Gas. Columbia Gas of Massachusetts and Columbia Gas of Ohio are sister companies. They share a parent company and operate under the same O&M Manual. The Panel collected information about the organization's response to the Zanesville incident to better understand Columbia Gas of Massachusetts' processes concerning investigating incidents, learning from incidents, and reporting incidents to PHMSA.

16 Although the Panel's observation of Columbia Gas of Massachusetts' construction and maintenance work was limited due to work restrictions imposed by the DPU, the Panel believes it had sufficient opportunity to identify the strengths and opportunities set forth in Appendix B.3. In addition, the DPU selected the Panel to conduct a separate and independent assessment of Columbia Gas of Massachusetts' work related to its restoration of gas service following the Merrimack Valley incident. The culmination of that assessment will be the subject of a future separate report.

and the number of construction sites visited at each Gas Company varied, depending upon Gas Company size, number of operating areas, and the amount and variety of projects underway during the Panel's visit.[17]

Activities and facilities the Panel requested to see included, but were not limited to, the following:

- Visiting various field offices, construction yards, construction/maintenance locations, and various gas facilities including gate stations, district regulator stations, and where relevant, gas control facilities;[18] and
- Observing work arising out of the Massachusetts Gas Safety Enhancement Program (GSEP)[19] or other construction activities, maintenance activities, work at district regulator stations, leak repairs, live gas work (including tie-ins), new service or meter installations and/or meter replacements, and locating and marking activities; and
- Being informed real-time of any Grade 1 leaks, line hits, or other abnormal operating conditions that may occur during the visit, which allowed the Panel to observe the response to those situations.[20]

In Phase 2, the Panel visited over 150 different field sites and spent over 25 days in the field, working an estimated 57-person days in the field. For Gas Companies with more than one service area, the Panel undertook visiting work sites in various representative locations to the extent possible. The locations of the field visits are represented in Figure 2. More details of the site field visits for each Gas Company are set forth in the Gas Company Snapshots in Appendix B.

[17] The Panel and the Gas Companies' efforts to keep the timing and location of the field visits confidential was largely successful. Even when the Panel's presence became known by crews at site, the Panel observed no meaningful changes in their work performance.

[18] See Footnote 11 (the Panel visited LNG plants opportunistically).

[19] The 2014 GSEP law allows a gas company to file a plan with the DPU to "address aging or leaking natural gas infrastructure within the commonwealth in the interest of public safety and reducing lost and unaccounted for natural gas through a reduction in natural gas system leaks." Such a plan "shall include, but not be limited" to removal of eligible leak prone infrastructure of non-cathodically protected steel, cast iron and wrought iron with a target end date of either (i) not more than 20 years, or (ii) a reasonable target end date considering the allowable recovery cap. *See* Section 145 of Chapter 164 of the General Laws.

[20] The Panel's field visits were not intended to constitute a compliance audit, nor were they based on an application of rigorous metrics across each of the Gas Companies as might be used by the DPU or other regulatory agencies that have traditionally relied upon a more structured review process. Instead, the Panel maintained the latitude to use its expertise and experiences to interview personnel and make observations on the sites that went beyond compliance – to make observations and recommendations to improve pipeline safety across the Commonwealth.

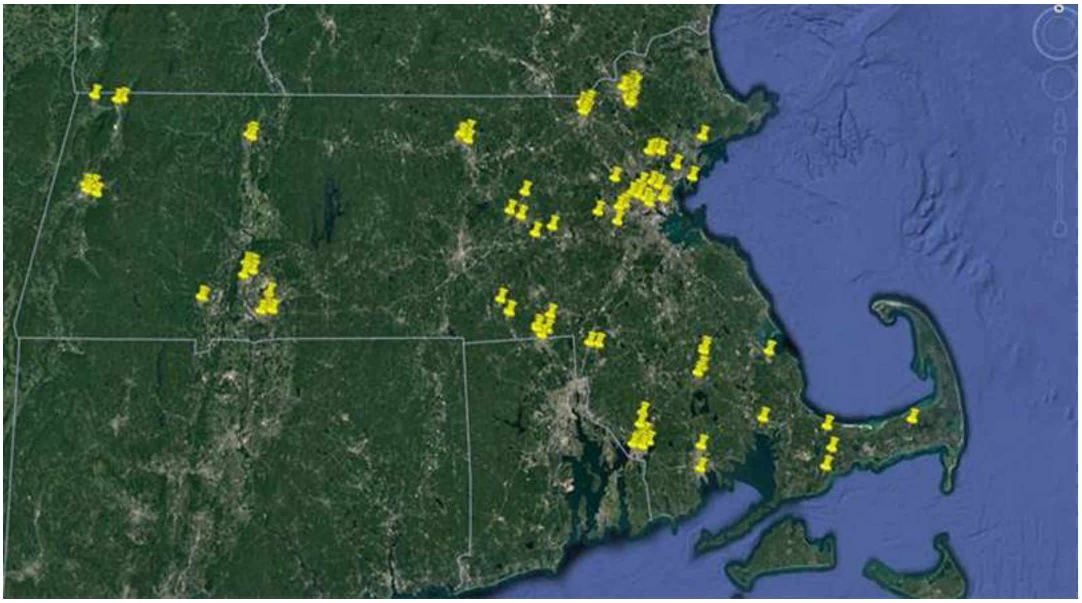

Figure 2: Field Visit Map

3.2.2 Other Workstreams

In Phase 2 the Panel also undertook new work streams as well as completing earlier ones.

Foremost was the further development of safety culture aspect of this Assessment. This included reaching out to experts in fields of expertise outside the pipeline industry to develop a better understanding of what safety culture is, and is not, how it functions in context with gas distribution failures, how to discern what are appropriate indicators or measurements, and how to assess safety culture. This work resulted in the *White Paper* in Appendix A.

In addition, Phase 2 also included:

- Further developing the analyses of the effectiveness of the GSEP pipe replacement when measured by the number of gas leaks;
- Working to better understand the PHMSA incident data related to incidents on gas distribution systems in the US, the Northeast, and Massachusetts;
- Gathering information from the Gas Companies on leaks discovered and over-pressurization events on each of their systems, and that of affiliates operating under similar O&M manuals, if any, from 2013 to 2018;[21]
- Understanding the roles and effectiveness of government agencies, such as the DPU, in promoting gas pipeline safety; and
- Reviewing numerous industry reference materials.

[21] The Panel sought information from affiliated companies because they generally operate under the same procedures and corporate management. As such, each Gas Company is expected to learn from the experiences of its affiliates. Each of the Gas Companies responded to this request, except Eversource which declined to provide the information for any gas systems operated outside of Massachusetts. See Appendix B.4, Eversource.

4 Stakeholder Groups and Interested Parties

As discussed in the *Phase 1 Report*, the DPU and the Panel recognizes the need for transparency and stakeholder engagement in this Assessment. While this Assessment needs to cover the technical aspects of pipeline safety, it must be conducted in a manner that also builds and enhances public trust and confidence in work product(s) produced by this Assessment. To help accomplish those goals, three Assessment Stakeholder Groups were established:

1. Elected Officials (see Appendix D.5.1)

   This group comprises elected and appointed officials, including Massachusetts legislative leadership, Merrimack Valley officials, and town mayors.

2. Community Representatives (see Appendix D.5.2)

   This group comprises utility union representatives, interested members from the general public, the Massachusetts AG Office, the State Fire Marshall, and/or other individuals with subject matter expertise.

3. Industry Representatives (see Appendix D.5.3)

   This group comprises select executives from natural gas companies across the US, key pipeline industry associations and/or experts working in complex operations in other industries, such as nuclear power and commercial aviation.

Each of the Stakeholder Groups comprises individuals with a stake in the outcome of this Assessment. Appendix D.5 lists the names and titles of individuals who graciously shared time and energy helping improve pipeline safety in the Commonwealth of Massachusetts.

The role of each Stakeholder Group member was to participate fully in listening sessions and specifically to:

- Provide input, ideas, and considerations as the Panel progresses through this Assessment;
- Ensure the Panel discusses and includes relevant issues in this Assessment; and
- Respect boundaries regarding sharing information about the Stakeholder Groups, participants and discussions.

The Panel formally recognizes and thanks each participant in each Stakeholder Group. Each participant dedicated time thoughtfully and provided valuable input to the Panel in Phase 1 and Phase 2.[22] The Panel found the stakeholders full and candid participation during the listening sessions most helpful.

While active engagement of Stakeholder Groups was a critical element during this Assessment, the Panel is solely responsible for the assessments, observations, and recommendations set forth in this Final Report.

[22] With the Panel's main focus in Phase 2 on the individual Gas Companies, the involvement of Stakeholders has been more limited. See Section 4.2 for a discussion of Stakeholders' involvement in Phase 2.

4.1 Phase 1 Stakeholder Meetings

The Panel held separate listening sessions in mid-January and early March 2019 with each of the three groups. Topics of interest and concern raised by the stakeholders related to the scope of this Assessment included:

- Individual Gas Companies:
    - Physical characteristics of the natural gas distribution system.

      This included concerns about the age of the assets, sources of gas leaks, the timing and extent of replacement of leak prone pipes in GSEP, and the use, or lack of use, of current technology.
    - Personnel and training.

      This included concerns about staffing levels, adequate training, system knowledge transfer, use of contractors versus employees, impacts of multi-national organizations, and impacts of former employees working as regulators.
    - Procedures and programs.

      This included the adequacy of specific procedures, such as operating and maintenance procedures, and whether following procedures is sufficient to achieve pipeline safety, and the role of management of change[23] in procedures and other contexts.
    - Performance and execution of O&M activities. This included the role, impact or status of:
        - Compliance with regulations;
        - Success of repairs;
        - Construction mistakes;
        - Company inspectors;
        - Effectiveness of quality assurance programs across the operational spectrum;
        - Impacts of permit requirements;
        - Safe and effective execution of projects; and
        - Industry best practices.
    - Risk management practices (i.e., understanding and managing risk in gas systems). This included:
        - Knowing systems sufficiently to identify and mitigate risks;
        - Understanding the most significant risks (within the company, in the Northeast, and in the industry);

[23] The phrase *Management of Change* describes a leading practice used to ensure that safety, health, and environmental risks, and hazards are properly controlled when an organization makes a change to their facilities, operations, or personnel. It involves steps that include planning and communications before the change is made, actively monitoring, managing and implementing the change (including training), and then reviewing the effectiveness of the change to continually improve the process of managing the change.

    - Mitigating the risks of excavation damage and understanding the role of statutory exemptions in increasing risk; and
    - Recognizing the state of in-place Gas Company records, processes, and efforts to improve recordkeeping by accurately capturing data each time Gas Company work exposes existing buried assets.

- Role of the Regulator in pipeline safety and the effect of regulation on the Gas Companies. This included:
    - The effectiveness of DPU inspections;
    - If current Massachusetts requirements effectively achieve safer operations;
    - Ensuring Gas Companies comply with Consent Orders related to enforcement actions;
    - Impacts of self-reporting on penalties;
    - The rate-making process;
    - The need to find the balance between affordability and the benefits of planning gas asset investments over the course of time; and
    - The impact of focusing on compliance.
- Preparedness of the Gas Companies and the Commonwealth for emergency response. This included:
    - The level of preparedness to respond to a serious gas emergency;
    - The knowledge and appropriate levels of participation in an Incident Command Structure;
    - Knowledge of assets and communities;
    - Communication protocols;
    - Preparation for a broad spectrum of possible events;
    - Appropriate levels of investment in preparedness; and
    - Appropriate uses of technology.
- Reliability of gas supply and resiliency of citizens to widespread gas outages without notice; and
- Desire for the results of this Assessment to provide basis for sound policy decisions.

Stakeholder concerns also included:

- The specific goals and methods used in conducting this Assessment; and
- The manner in which the Panel would be reporting its recommendations to the DPU and the expectation that this Assessment will help legislators and citizens understand the current status of pipeline safety within the Commonwealth, including how to better assess risk and safety, and to provide a path forward to improve it.

Each of these perspectives were considered by the Panel as it completed this Final Report.

4.2 Phase 2 Stakeholder Meetings

Following the release of the *Phase 1 Report*, the Panel held Listening Session No. 3 with each of the Stakeholder Groups. At this Listening Session, the Panel solicited input from the Stakeholders on the *Phase 1 Report*, provided an update on Phase 2 schedules, and engaged the Stakeholders on the importance of creating a collaborative process to overcome the organizational goal conflicts that adversely impact pipeline safety in the Commonwealth. The Commercial Aviation Safety Team (CAST) was discussed as a possible model for successfully focusing all parties on the goal of improving pipeline safety in the Commonwealth. (See Appendix A, *Safety Culture White Paper* for further discussion of CAST as an example of one method to develop a strong positive safety culture in an industry.)

The Panel made the same presentation to the Gas Company representatives the following day. All 11 Gas Companies participated, and most provided some input and feedback on the need for a collaborative approach as exemplified by CAST.

On May 31, 2019, at the request of the Massachusetts AG Office, the Panel listened to feedback from several members of the AG's Office about their concerns with the portrayal of the AG's Office in the *Phase 1 Report*.

In an email in mid-August 2019, and again in early December 2019, the Panel updated the Stakeholders on the progress of the field visits and the anticipated completion date of the Final Report.

4.3 Interested Parties

As discussed in the *Phase 1 Report*, several entities, groups of people and organizations play a fundamental role in natural gas pipeline safety within the Commonwealth. For the purposes of this Assessment, the Panel refers to these entities and groups as Interested Parties. Many, but not all, of the Interested Parties are participating in aspects of this Assessment as members of the Stakeholder Groups or otherwise. Each of the Interested Parties may have many different roles and responsibilities.

For clarity and purposes of discussion within this Assessment, the following is a brief description of the Interested Parties, and their key organizational goals or objectives that impact natural gas pipeline safety within the Commonwealth:

- State Legislators

  Enact legislation and otherwise make or influence public policy.

- Massachusetts Executive Office of Energy and Environmental Affairs (EEA)
  - Responsible for overseeing energy and environmental policies for the Commonwealth.
- Department of Environmental Protection (DEP)

  Promotes laws and policies to protect the environment and reduce greenhouse gas emissions, among other responsibilities.[24]

[24] The *Department of Public Utilities* and the *Department of Environmental Protection* are just two of the many departments and divisions that EEA oversees. For more information on the breadth of activity undertaken and overseen by the EEA, see the listing of organizations and divisions on the EEA's website: https://www.mass.gov/topics/executive-office-of-energy-and-environmental-affairs

- Massachusetts's Department of Public Utilities (DPU)

  Enforce pipeline safety regulations and provide oversight of Gas Companies, among other responsibilities.[25]
- Massachusetts's Department of Energy Resources (DOER)

  Develop policies related to the Commonwealth's energy supply, among other responsibilities. Responsible for energy supply shortage contingency plans.
- U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA)

  Provide Federal oversight and enforcement of Federal pipeline safety laws, issue advisory bulletins, collect annual report and incident data, and establish new regulations. As permitted under Federal law, PHMSA has delegated its oversight and enforcement of Federal pipeline safety laws related to intrastate pipelines in Massachusetts like those operated by the Gas Companies to the DPU;
- AG Office, Ratepayer Advocate (AG Office)

  Intervene in Gas Company matters, including rate case matters before the DPU; scrutinize Gas Company budgets and operating proposals to keep rates as low and as steady as possible.[26]
- Utility Unions

  Promote fair and equitable treatment of members, and safety and safe work environments for members.
- Environmentalists

  Advocates, including concerned citizen groups, with a mission to reduce fossil fuel use and transition away from hydrocarbons. Advocates for lower greenhouse gas emissions by eliminating gas leaks, among other measures.
- Gas Companies

  Provide safe and reliable natural gas service to homes and businesses based on public policy and demand, and within financial recovery parameters allowed by the Commonwealth.
- Customers

  Desire safe, reliable, and affordable natural gas to cook food, heat homes, and run businesses.
- Municipal Governments

  Establish local permitting and requirements for pipeline safety work activities.

All entities must find a way to focus efforts on the commonly held objective of improving pipeline safety within the Commonwealth.

[25] The *Department of Public Utilitie*s (DPU) is a quasi-adjudicatory agency led by a three-member Commission. The Pipeline Safety Division is just one division of many in the DPU. Among its roles and responsibilities, the DPU "oversees investor-owned electric power, natural gas, and water companies in Massachusetts. The DPU regulates the safety of passenger-for-hire bus companies, provides oversight of moving companies, tow companies, and transportation network companies. In addition, the DPU is charged with developing alternatives to traditional regulation, monitoring service quality, regulating safety in public transportation and gas pipelines, and the siting of energy facilities." DPU 2017 Annual Report, page 6.

[26] Massachusetts law requires an office of ratepayer advocacy within the office of the AG. The law permits the office of ratepayer advocacy to intervene, appear and participate in state or Federal administrative, regulatory, or judicial proceedings on behalf of any group of consumers in connection with any matter "involving rates, charges, prices and tariffs" of a variety of entities including gas companies. MA General Laws, Part 1, Title 2, Chapter 12, Section 11E.

5 Pipeline Safety Basics

5.1 Accountability for Safety

As noted in the *Phase 1 Report* and repeated in many of the discussions by the Panel with Stakeholders and others, each Gas Company is accountable for safely designing, operating, and maintaining its own natural gas distribution systems to reliably and safely deliver natural gas to customers.

It is important to recognize, however, that each Gas Company operates in a complex setting in which there may be many competing internal and external goals and priorities that can distract from the requisite focus on, and designation of resources to, pipeline safety, the necessary commitment to continually learn and improve, and the development of a strong positive safety culture.

As discussed in this Final Report, each of the Gas Companies have opportunities to improve pipeline safety. Likewise, each of the Interested Parties plays a role in gas pipeline safety and improving pipeline safety.

5.2 The Role of Personal Safety

Personal safety is an important foundation for, but does not comprise the entirety of, pipeline safety. Focusing on developing good personal safety habits – such as wearing appropriate personal protection equipment (PPE) on a job site, backing a car into a parking spot, or holding on to the railing while descending stairs – are appropriate personal safety areas for Gas Companies to focus employees.

Pipeline safety includes personal safety but is mainly concerned about safeguarding the public by enhancing practices that keep natural gas in the pipeline. Throughout this Assessment, the Panel almost uniformly observed that when an individual claimed the company was focused on safety, the explanation led to discussion about personal safety rather than pipeline safety.

Notably, personal safety is a topic that lends itself to measurements. Injuries, days away from work, and traffic accidents are readily collected and measured. Insights for improvement are readily apparent.[27] Such improvements are good for the health of the workers, but do not directly improve pipeline safety. Moreover, it is possible that focusing on personal safety might decrease pipeline safety by reducing management attention and creating a false sense of security.

Questions about pipeline safety increasingly need to focus on process safety, recognizing that systems will fail, and designing them for redundancy so when they do fail, the failure does not harm personnel or the public.

[27] For example, companies track the number of traffic accidents within their workforce, and use a decrease in this statistic as evidence of improved pipeline safety. If there is an increase in a certain type of accidents, such as while backing up a vehicle, the company may develop improvement opportunities that could include more driver training or a change in policy that adopts a different vehicle driving method (e.g., such as backing into spaces before leaving a vehicle or conducting a 360 review of the area around the vehicle before getting behind the wheel) to reduce the number of backing vehicle incidents. Because the number of backing incidents are easy to count, a decrease can provide evidence of improvement.

5.3 Identifying and Managing Pipeline Integrity Threats to Pipeline Safety[28]

Safely constructing, maintaining, and operating a natural gas pipeline system is a complex endeavor. Among other things, it requires Gas Companies to know their systems and proactively take steps to identify and reduce or eliminate threats to safe product delivery. Pipeline integrity management (integrity), which is the conventional, primary method for accomplishing this goal, requires Gas Companies to identify and manage potential threats to pipeline integrity and reduce risks on pipeline systems. Integrity management considers:

- Physical assets, such as leak prone pipe;
- Other risks, such as weather, dig-ins, and terrorism;
- Threat-based analysis and mitigation efforts; and
- The distinct threats and risks that different asset-types face.

Based on a well-established and recognized engineering standard, the pipeline industry categorizes threats to the structural integrity of pipelines like this:

- Time-Dependent:
    - External corrosion;
    - Internal corrosion; and
    - Stress corrosion cracking.
- Resident (or Stable):
    - Manufacturing-related defects (manufacturing flaws or defects in the pipe or other materials);
    - Welding/fabrication related defects (pipe fusion; coupling failures, faulty T-joints); and
    - Equipment malfunction (control/pressure relief equipment malfunction).
- Time-Independent:
    - Third party/mechanical damage;
    - Incorrect operations (e.g., operator error); and
    - Weather-related and outside forces (e.g., frost heave).

Gas Companies must identify which of these threats are applicable on each segment of its system, and then undertake efforts to understand, manage and mitigate these threats in an effort to prevent failures.

Federal regulation[29] require each Gas Company to set forth its Distribution Integrity Management Program (DIMP) in a written procedure. The DIMP is the tool companies use to identify the specific

[28] The word “threats” as used herein is a term specific to pipeline integrity management. It means those characteristics or actions that, if left unmitigated, could potentially represent a threat to the structural integrity of the pipeline and reduce its ability to contain the product being transported.

[29] 49 CFR Part 192, Subpart P, Gas Distribution Pipeline integrity Management (describing the minimum requirements for an integrity management program).

threats and mitigation plans designed to address the threats. DIMPs are expected to continue to evolve and mature over time as more information and data are developed.

As discussed in the *Phase 1 Report*, each of the Gas Companies has a DIMP that generally meets the regulatory compliance requirements.[30] Going beyond mere compliance with more robust DIMPs, National Grid, Eversource, and Unitil[31] appear to utilize their DIMPs as a vehicle for developing a better understanding and mitigating risks associated with its gas systems.[32] While the DIMP used by Columbia Gas had some of the same characteristics utilized by National Grid, Eversource, and Unitil, the organizational view within Columbia of the program as, basically, a leak management program keeps it from being grouped as one of the exceptions to treating the DIMP as a compliance requirement.[33] A more specific assessment of the state of each Gas Companies' DIMP for 2018 is set forth in Gas Company Snapshots in Appendix B.

[30] While these plans appear to meet the minimum compliance requirements, most of the Gas Company DIMPs did not appear to have many of the characteristics of an actively used distribution integrity plan demonstrating continued learning and evolution of the program. These characteristics include, for example, having a plan that is being updated regularly based on newly discovered information (gathered from updated records or investigations into critical as events or near misses), increasingly relying more on data (and becoming less reliant solely on opinions of subject matter experts), and developing and testing mitigation measures for effectiveness. A DIMP that went beyond compliance also would demonstrate a strong link between the program and decision-making around prioritizing project and have a clear "owner" in the organization with accountability for development and implementation of the DIMP. Importantly, the DIMP would be aligned with the company's risk management approach.

[31] See National Grid, Eversource and Unitil in Appendix B.

[32] These programs used more data, rather than the relying solely on the opinions of its subject matter experts, and considered external information about the potential risks to their systems but have more opportunities for maturation.

[33] See Appendix B.3, Columbia Gas.

6 Observations Roadmap

As part of this Assessment, the Panel developed various observations that led to the recommendations in Section 12. The discussions of Panel observations are grouped by:

- Safety Culture (Section 7);
- Massachusetts Gas Assets (Section 8);
- Gas Companies, in general (Section 9);
- Each Gas Company, in the Gas Company Snapshots in Appendix B;
- Beyond the Gas Companies (DPU, AG Office, and Interested Parties) – Section 10; and
- Best Practices (Section 11).

7 Safety Culture

Developing and maintaining a strong positive safety culture within an organization is an important factor in pipeline safety. Safety culture is the pervasive force that flows through an organization and colors every action it takes. This is true whether or not the presence of a safety culture is recognized or acknowledged by the organization. The *White Paper* (see Appendix A), written in collaboration with a leading researcher on safety culture, discusses safety culture as a concept to explain why organizations with complex safety systems and engineering controls fail to prevent major incidents. In essence, the safety culture of an organization determines two important keys to safe operations of safety critical systems:

1. It determines the effectiveness of safety management systems; and
2. It determines the gap between described control measures and the implementation of these controls.

Reviews of major safety incidents consistently conclude that effective control measures were available to control the hazard that caused the safety incident, but were either not adopted by the organization or, more often, they were not implemented as intended. Both of these findings reflect a poor safety culture because the organization did not:

- Allocate adequate resources for safety management; and
- Ensure that appropriate controls were in place and effective.

In addition, warning signs of a problem typically have been ignored. It can appear (with the benefit of hindsight) that the organization suffered from collective blindness, as they did not see how far practice had deviated from the plan. As the *White Paper* explains, conducting an effective safety culture assessment is a complex, multi-faceted endeavor that must be conducted over a period of time with full access to a number of levels of personnel within the organization. While such a work stream is outside of the scope of this Assessment, the Panel believes understanding, assessing, and enhancing safety culture is likely the most meaningful way to effectively improve pipeline safety within the Commonwealth over the long term.

Safety perception surveys may be used as one tool in a broader effort to assess safety culture. It is important to be aware, however, these surveys only assess employees' perceptions of safety commitment or attitudes towards safety, which provide limited information about safety culture. As discussed in the *White Paper*, concluding the company has a positive safety culture based solely on perceptions of surveys is usually misplaced for several reasons:

1. Perception surveys typically only contain general statements about safety and, therefore, reflect personal safety rather than process or public safety;
2. There are a wide variety of surveys available and their quality varies significantly. A poor-quality survey can produce misleading results;
3. Perceptions are easily biased and can be influenced by many factors, such as changes to working conditions or concerns about job reductions; and
4. The purpose of a safety culture assessment is to identify improvement opportunities as part of developing a positive culture focused on continuous improvement, not as a mechanism to tout progress.

The Panel observed such misplaced overconfidence in at least one Gas Company. In one example, the Gas Company had hired a third-party quality assurance company to conduct a safety culture review. The Gas Company received a 98% positive score for safety culture. This gave management a great deal of comfort in the Company's operations. In contrast, this was one of the Gas Companies at which the Panel had observed a number of immediate safety concerns.[34] This example suggests these third-party perception surveys may be providing management with a false sense that things are being done safely and in the way that the company's leadership thinks it is getting done.

[34] See Appendix B.11.3 Westfield.

8 Observations About Massachusetts Gas Assets

The Panel's observations about the Massachusetts natural gas pipeline assets are set forth in this section. These observations are organized into four categories:

1. Gas distribution infrastructure (Section 8.1);
2. Massachusetts GSEP (Section 8.2);
3. PHMSA incident data (Section 8.3); and
4. Safety risks associated with reliability of natural gas supply (Section 8.4).

8.1 Gas Distribution Infrastructure in Massachusetts

As part of the process of understanding the nature of the natural gas distribution pipeline assets located in Massachusetts, the Panel undertook a review of data:

- Collected by PHMSA from individual Gas Company annual reports;[35] and
- Supplied by the Gas Companies in response to the Panel's information requests.

As background, Gas Companies are required to report certain information to PHMSA each year.[36] This information, submitted in the form of an Annual Report, provides detailed information related to the gas pipeline infrastructure for each Gas Company.[37] These Annual Reports offer details related to the 1.3 million miles of mains and the 69.3 million services that operate across the country.[38]

The definition of *leak prone pipe* as referenced in this Assessment considers cast iron pipe, including wrought iron, and unprotected steel[39] pipe. This is the same as the GSEP definition.[40] This definition enables a comparison between gas distribution systems across the US, Northeast US, and within Massachusetts.

PHMSA's annual reports also provide information about the number of gas leaks *repaired* in a given year. To provide a better view of the condition of the assets, the Panel asked the Gas Companies to provide data on the number of gas leaks *discovered* in each year from 2013-2018.[41]

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[35] Annual Report - Gas Distribution System, Form PHMSA F 7100.1-1 (rev 10/11/2018), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[36] All 50 states, plus DC and Puerto Rico, submitted annual reports with distribution pipeline mileage in 2018.

[37] These data summarize the gas pipeline infrastructure and provide specific details requested by PHMSA including, but not limited to, material, pipe diameter, decade of construction, and also provide additional information about leaks repaired during each calendar year. For example, these data do not provide sufficient granularity to segregate both specific materials (e.g., cast iron) or by specific diameter (e.g., less than or greater than 12 inches).

[38] Distribution gas systems are comprised of mains and services. Mains generally distribute gas into an area. Services (or service lines) deliver gas from the mains to homes or business.

[39] The terms *protected* and *unprotected* refer to whether or not cathodic protection is used to mitigate external corrosion on the pipeline. For example, a pipe may be considered unprotected if it is not cathodically protected. This category of unprotected steel includes coated and uncoated pipe. Coated pipe is a steel pipe with an external coating.

[40] As discussed in Section 8.2.5, the Panel presents observations related to including candidate pipe types for replacement beyond those currently defined within GSEP.

[41] See Appendix F for a comparison between these two metrics. Also see Section 8.2.4 for an analysis of leak data and the questions it raises about the choices being made regarding which segments of leak prone pipe is being replaced.

The Panel utilized this data to:

- Analyze the current state of the Massachusetts natural gas assets as compared to the Northeast and the US;
- Provide context for leak prone pipe in Massachusetts; and
- Consider the pace and trajectory of reducing risk under GSEP (see Section 8.2).

A summary of 2018 PHMSA data based on the Annual Reports[42] of the total and amount of leak prone pipe of mains and services in the US, Northeast, and Massachusetts is provided in Table 1 and Table 2, and for Gas Companies in Table 3.

8.1.1 PHMSA has long recognized the risk associated with leak prone pipe.

While the natural gas distribution systems in Massachusetts are generally reliable, leak prone pipe should be replaced to enhance long-term safety and reliability of gas service, and for environmental reasons. PHMSA[43] first identified the need to remove cast iron pipe from natural gas distribution systems in an alert bulletin issued in October 1991 and again in June 1992.[44] This was based on the national data, which supported a higher risk of failure for cast iron pipe in distribution systems. The likelihood that a gas leak will occur on such leak prone pipe far exceeds the likelihood of a leak occurring on more modern pipe.[45]

PHMSA's analysis of incident data (2005-2018) indicates:

- 10% of the incidents occurring on gas distribution mains involved cast iron mains. However, only 2% of distribution mains are cast iron;
- 38% of the cast/wrought iron main incidents caused a fatality or injury, compared to only 20% of the incidents on other types of mains; and
- 38% of all fatalities and 17% of all injuries on gas distribution mains involved cast or wrought iron pipelines."[46]

Efforts to reduce the amount of cast iron and unprotected steel pipe across the country have largely succeeded. PHMSA reports, that by the end of 2018, approximately 94% of natural gas distribution mains in the US were made of plastic or steel (protected). Compare this to 77% within Massachusetts. Twenty-two states and one territory (Puerto Rico) no longer have cast iron mains in their distribution systems.[47]

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[42] See PHMSA Annual Reports. A summary as of 2017 of the status of the mains and services in the Northeast and in MA, which was presented in the *Phase 1 Report*, is set forth in Appendix I.1.

[43] The Federal government first began regulating natural gas pipelines in 1971. See also, Section 8.2.6, which discusses pipe installed before the advent of PHMSA-regulations.

[44] See PHMSA Alert Notices ALN– 91–02 dated October 11, 1991 and ALN–92– 02 dated June 26, 1992.

[45] See example in Appendix E.

[46] See PHMSA website: https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory

[47] See PHMSA website, Pipeline Replacement Update at: https://opsweb.phmsa.dot.gov/pipeline_replacement/
The states and territories include AK, AZ, AR, CO, HI, IA, ID, MT, NM, NC, ND, NV, OK, OR, PR, SC, SD, UT, VT, WA, WI, and WY.

8.1.2 Massachusetts has a higher proportion of leak prone pipe when compared to its share of total pipeline miles.

Based on 2018 PHMSA database information, Massachusetts has a higher proportionate share of leak prone pipe in both gas mains and gas services when compared to its overall share of gas distribution pipe. As a summary, the approximate breakdown by type of pipe for mains and services is as follows:

- Mains:
  - Massachusetts has 2% of the total miles of mains in the US
    - 21,714 miles of 1.30 million miles (approximately)
  - Massachusetts has 13% of the cast iron mains in the US
    - 2,925 miles of 22,868 miles
  - Massachusetts has 4% of the steel (unprotected) mains in the US
    - 2,157 miles of 52,462 miles
- Services:
  - Massachusetts has 2% of the services
    - 1.3 million of 69 million services (approximately)
  - Massachusetts has 20% of the cast iron services in the US
    - 1,373 of 6,985 services
  - Massachusetts has 6% of the steel (unprotected) services in the US
    - 189,000 of 2.9 million services

This summary of the mains and services shows that Massachusetts has a greater proportion of leak prone pipe (cast iron and unprotected steel services and mains) when compared to its share of total miles of mains and number of services across the US. While Massachusetts operates approximately 2% of the mains and services in the US, cast iron mains and services in the state account for 13% and 20% of the cast iron, respectively, in the US.

8.1.3 Northeast US has a higher proportion of leak prone pipe when compared to its share of total pipeline miles.

There is a higher proportion of leak prone pipe in the Northeast when compared to its share of total main miles of gas distribution pipe in the US (see Table 1). Based on the 2018 PHMSA data, the Northeast has over 64% of all cast-iron main pipes in the nation, even though it has only 13% of the total main pipe miles in the US. The Northeast has over 78% of the cast-iron services even though it has only 15% of the services in the US. These data are in Table 1.

The following summarizes the total leak prone gas mains in the Northeast (approximately) when compared to the US:

- 13% of total main mileage (170,000 in the Northeast of 1.30 million US miles);
- 64% of cast iron main mileage (15,000 miles in the Northeast of 23,000 US miles); and
- 33% of steel (unprotected) main mileage (18,000 miles in the Northeast of 52,000 miles).

Of the total pipeline miles within Massachusetts, approximately 23% of mains were characterized as leak prone as of 2018 (cast iron or unprotected steel), and about 14% of services were leak prone as of 2018 (cast iron or unprotected steel). The percentages presented in parentheses in Table 1 and Table 2 identify percentages within each state.

Table 1: Mains – Miles in Northeast, US, and MA (2018)

State	Miles Main (% Total Main)			
	Total Main	Cast Iron	Steel (Unprotected)	Leak Prone
NY	49,307	3,175 (6%)	6,125 (12%)	9,300 (19%)
PA	48,501	2,532 (5%)	7,378 (15%)	9,909 (20%)
NJ	35,007	3,911 (11%)	1,294 (4%)	5,205 (15%)
MA	21,714	2,925 (13%)	2,157 (10%)	5,082 (23%)
CT	8,168	1,221 (15%)	173 (2%)	1,394 (17%)
RI	3,201	700 (22%)	386 (12%)	1,086 (34%)
NH	1,989	81 (4%)	21 (1%)	101 (5%)
ME	1,285	36 (3%)	11 (1%)	46 (4%)
VT	862	-0.0%	-0.0%	-0.0%
NE Total	**170,034**	**14,580 (9%)**	**17,544 (10%)**	**32,124 (19%)**
US	1,307,792	22,868 (2%)	52,462 (4%)	75,330 (6%)
NE % of US	13%	64%	33%	43%
MA % of US	2%	13%	4%	7%

Table 2: Services – Number in Northeast, US and Massachusetts (2018)

State	Count of Services (% Total Services)			
	Total Services	Cast Iron	Steel (Unprotected)	Leak Prone
NY	3,255,165	3,847 (0.1%)	353,401 (11%)	357,248 (11%)
PA	2,870,271	73 (0.0%)	286,370 (10%)	286,443 (10%)
NJ	2,329,992	(0.0%)	186,188 (8%)	186,188 (8%)
MA	1,348,782	1,373 (0.1%)	189,535 (14%)	190,908 (14%)
CT	453,505	17 (0.0%)	42,515 (9%)	42,532 (9%)
RI	197,147	127 (0.1%)	41,793 (21%)	41,920 (21%)
NH	93,857	14 (0.0%)	5,902 (6%)	5,916 (6%)
ME	36,890	24 (0.1%)	176 (%)	200 (1%)
VT	40,680	0 (0%)-	0 (0%)-	0 (0%)-
NE Total	**10,626,289**	**5,475 (0.1%)**	**1,105,880 (10%)**	**1,111,355 (10%)**
US	69,347,103	6,985	2,922,152	2,929,137
NE % of US	15%	78%	38%	38%
MA % of US	2%	20%	6%	7%

Table 3: Mains and Services for Massachusetts Gas Companies (2018)

Gas Co.	PHMSA ID	Total Main	Main: Cast Iron	Main: Steel (Unp.)	Main: Leak Prone	Total Services	Services: Cast Iron	Services: Steel (Unp.)	Services: Leak Prone
Investor-Owned Local Distribution Companies (7)									
NGC		11,130	1,896	1,186	3,082	761,382	1,363	108,918	110,281
BOS	*1640*	*6,370*	*1,736*	*1,071*	*2,806*	*511,285*	*1,345*	*96,946*	*98,291*
ESS	*4547*	*870*	*72*	*18*	*90*	*52,677*	*3*	*4,201*	*4,204*
COL	*11856*	*1,402*	*88*	*64*	*152*	*78,433*	*-*	*4,641*	*4,641*
CAP	*2066*	*2,488*	*0*	*34*	*34*	*118,987*	*15*	*3,130*	*3,145*
EVE	2652	3,292	317	638	955	204,947	8	28,484	28,492
CGM	1209	4,990	424	199	623	273,847	-	34,613	34,613
LIB	31770	619	102	73	175	36,828	-	9,926	9,926
BER	1344	761	50	32	82	32,247	1	2,611	2,612
UNI	5200	273	44	6	50	11,070	-	1,979	1,979
BLA	1504	55	-	-	-	1,470	-	-	-
Municipal Gas Companies (4)									
HOL	7330	185	52	-	52	8,477	-	1,065	1,065
MID	12444	107	6	1	7	4,853	-	177	177
WAK	22035	88	1	22	23	5,033	-	835	835
WES	22511	212	32	-	32	8,628	1	927	928
TOTAL		21,712	2,925	2,157	5,082	1,348,782	1,373	189,535	190,908

Notes:

1. Gas Company abbreviations and associated PHMSA identification numbers are:
   - NGC: National Grid (BOS, ESS, COL, CAP);
   - BOS: Boston Gas Co (1640);
   - ESS: Essex County Gas Co (4547);
   - COL: Colonial Gas Co – Lowell Div. (11856);
   - CAP: Cape Cod Gas Co (Div. Of Colonial Gas Co) (2066);
   - EVE: NSTAR Gas Company (2652);
   - CGM: Columbia Gas Of Massachusetts (Bay State Gas Co) (1209);
   - LIB: Liberty Utilities (New England Natural Gas Company) Corp (31770);
   - BER: Berkshire Gas Co (1344);
   - UNI: Fitchburg Gas & Electric Light Co (5200);
   - BLA: Blackstone Gas Co (1504);
   - HOL: Holyoke Gas & Electric Dept, City Of (7330);
   - MID: Middleborough Gas & Electric Dept (12444);
   - WAK: Wakefield Municipal Light Dept (22035); and
   - WES: Westfield Gas & Electric Light Dept (22511).
2. National Grid is used globally to include: BOS, ESS, COL and CAP. Although operated by National Grid, each of these companies continue to appear before DPU and PHMSA as separate entities. Data for each of these four organizations, in shaded grey, which is rolled into the number for NGC.

8.1.4 History and pace of replacement are factors in Massachusetts and the Northeast currently having a higher proportionate share of leak prone pipe.

As a matter of history, Massachusetts and the Northeast generally were settled and established earlier than other parts of the US. When natural gas pipelines were first installed, cast iron, and then unprotected bare steel pipe, were the materials of choice.[48] While more modern materials have been installed in more recent decades,[49] this vintage infrastructure has deteriorated over time and become leak prone.

In 2009, the DPU established a program that allowed certain Gas Companies to recover costs related to replacement of leak prone pipe, which likely increased the pace of replacement to some degree. As discussed in more detail below, the State legislature sought to accelerate the pace of replacement when it enacted new law introducing the GSEP in 2014 under which investor-owned Gas Companies began accelerating their pace of replacing leak prone pipe in 2015. This resulted in investor-owned Gas Companies generally adopting a plan to replace the remaining leak prone pipe over the next 20 years.

8.1.5 Complex Gas Companies have to manage more system risk than others.

As discussed more in the individual Gas Company Snapshots in Appendix B, each Gas Company has a unique set of natural gas distribution assets it must manage. Likewise, in addition to operational risks each company faces, each set of assets present different risks based on materials, size, system complexity, and operational challenges.[50]

As discussed in Section 8.1.1, one factor used to evaluate risk is the number of miles of leak prone pipe in a system. The current percentages of leak prone mains and service in Gas Company systems is set forth in Table 4 and Table 5, respectively.

While the Gas Companies have made efforts to reduce leak prone pipe before the inception of the current GSEP, a significant amount of leak prone assets remained in Massachusetts as of 2013 and still remains (end of 2018).

As shown in Table 4 and Table 5, at the end of 2018, the Gas Companies had over:

- 6,000 miles of leak prone mains; and
- 190,000 leak prone services.

Approximately half of the remaining leak prone pipe (mains and services) in Massachusetts is in the Boston Gas Company system that is part of National Grid.

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48 In addition, these materials were used to construct gas systems operating at a low pressure (in which the amount of pressure is often described in inches of water column rather than as pounds per square inch). Pressure on a low-pressure system is regulated at district regulator stations that are spaced periodically throughout the system to measure and regulate pressure in the system. Gas is delivered to homes via a house meter that is not equipped with regulators. This absence of a regulator on a house meter means that if the pressure rises on the low-pressure system, the amount of gas being delivered to the house increases. Often house meters on low-pressure systems are installed inside the house.

49 Modern materials include high density plastic pipe. With such materials, gas systems are constructed to operate at higher pressures than on a low-pressure system (for example, 60 or 99 psig). Too, as discussed in Section 8.2.2, these higher-pressure systems are accompanied by other safety benefits including excess flow valves, curb valves, and outside house meters with regulators at each meter set.

50 Section 8.1.5 discusses other factors, such as the size, and complexity of the systems and operational challenges, that impact risk.

Table 4: Mains – Miles of Leak Prone Main in Massachusetts (2013 and 2018)

Gas Company	PHMSA ID	2013			2018		
		Total Mains	Leak Prone Mains	Percentage Leak Prone	Total Mains	Leak Prone Mains	Percentage Leak Prone
NGC		11,021	3,634	33%	11,130	3,082	28%
BOS	*1640*	*6,324*	*3,230*	*51%*	*6,370*	*2,806*	*44%*
ESS	*4547*	*863*	*103*	*12%*	*870*	*90*	*10%*
COL	*11856*	*1,389*	*181*	*13%*	*1,402*	*152*	*11%*
CAP	*2066*	*2,445*	*121*	*5%*	*2,488*	*34*	*1%*
CGM	1209	4,875	1,023	21%	4,990	623	12%
EVE	2652	3,213	1,133	35%	3,292	955	29%
BER	1344	759	139	18%	761	82	11%
LIB	31770	609	229	38%	619	175	28%
UNI	5200	275	78	28%	273	50	19%
BLA	1504	51	-	0%	55	-	0%
WES	22511	207	40	19%	212	32	15%
HOL	7330	184	57	31%	185	52	28%
MID	12444	103	12	11%	107	7	7%
WAK	22035	84	34	41%	88	23	27%
Totals		**21,380**	**6,379**	**30%**	**21,712**	**5,082**	**23%**
MA		21,383	6,379	30%	21,714	5,082	23%
NE		165,695	40,285	24%	170,034	32,124	19%
US		1,255,451	91,504	7%	1,307,792	75,330	6%

Table 5: Services –Number of Leak Prone Services in MA (2013 and 2018)[51]

Gas Co.	PHMSA ID	2013			2018		
		Total Services	Leak Prone Services	Percentage Leak Prone	Total Services	Leak Prone Services	Percentage Leak Prone
NGC		720,001	129,971	18%	761,382	110,281	14%
BOS	*1640*	*490,951*	*114,663*	*23%*	*511,285*	*98,291*	*19%*
ESS	*4547*	*42,887*	*4,965*	*12%*	*52,677*	*4,204*	*8%*
COL	*11856*	*74,672*	*5,759*	*8%*	*78,433*	*4,641*	*6%*
CAP	*2066*	*111,491*	*4,584*	*4%*	*118,987*	*3,145*	*3%*
CGM	1209	260,097	48,330	19%	273,847	34,613	13%
EVE	2652	195,608	39,077	20%	204,947	28,492	14%
BER	1344	32,399	6,067	19%	32,247	2,612	8%
LIB	31770	35,659	13,711	38%	36,828	9,926	27%
UNI	5200	10,949	3,559	33%	11,070	1,979	18%
BLA	1504	1,292	-	0%	1,470	-	0%
WES	22511	8,362	1,454	17%	8,628	928	11%
HOL	7330	7,771	2,302	30%	8,477	1,065	13%
MID	12444	4,517	245	5%	4,853	177	4%
WAK	22035	4,914	1,377	28%	5,033	835	17%
Total		**1,281,569**	**246,093**	**19%**	**1,348,782**	**190,908**	**14%**
MA		1,281,569	246,093	19%	1,348,782	190,908	14%
NE		10,391,242	1,522,784	15%	10,626,289	1,111,355	10%
US		67,159,562	3,680,943	5%	69,347,103	2,929,137	4%

51 In comparing data collected in 2013 with data collected in 2018, there are two caveats related to Gas Companies making progress in revising records with updated information as it has become known. First, this can result in some oddities in the data. For instance, there may be cast iron reported in 2018 when none was reported in 2013. Second, improving older records based on newly discovered information may contribute to some newly counted leak prone pipe and services but it is unlikely to make a substantive difference in the magnitude of the rate of change calculations.

8.2 Massachusetts Gas Safety Enhancement Plan

The Massachusetts State legislature enacted a new law introducing the Gas Safety Enhancement Program (GSEP) in 2014.[52] Gas Companies increased the pace of replacement of leak prone pipe under GSEP's rate recovery mechanism. Gas Companies generally adopted a plan to replace the remaining leak prone pipe over the next 20 years. Observations related to GSEP and the process for supporting and executing this program are provided in sections 8.2.1 to 8.2.7.

8.2.1 GSEP is an example of a legislative and regulatory success with room for improvements.

As discussed in the *Phase 1 Report*, the Panel observes that GSEP is an example of a legislative and regulatory success with opportunities for continued improvement to continue to enhance public and pipeline safety. Enacted in 2014, GSEP was intended to increase the pace of replacement of leak prone pipe by Gas Companies by adopting a method by which Gas Companies can recover the costs of the replacement work, capped at a certain percentage of a company's annual revenue, in a timely manner.[53] While there are opportunities to improve the program, as discussed in Section 8.2.7, GSEP is a key program that assists in accomplishing these goals.

This rate recovery mechanism benefits Gas Companies and customers by enabling companies to more effectively plan ahead, by obtaining materials, acquiring needed equipment, and planning for managing increased labor needs. This includes hiring personnel or by entering into longer-term contracts with more favorable financial terms.

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[52] The 2014 law allows a gas company to file a plan with the DPU to "address aging or leaking natural gas infrastructure within the commonwealth in the interest of public safety and reducing lost and unaccounted for natural gas through a reduction in natural gas system leaks." Such a plan "shall include, but not be limited" to removal of eligible leak prone infrastructure of non-cathodically protected steel, cast iron and wrought iron with a target end date of either (i) not more than 20 years, or (ii) a reasonable target end date considering the allowable recovery cap. *See* Section 145 of Chapter 164 of the General Laws.

[53] Rather than waiting for the filing of a full rate case, the GSEP rate recovery mechanism requires a company to engage in a regulatory proceeding about GSEP replacement plans and expenditures with the DPU, in which the AG's Office Ratepayer Advocate participates, twice a year. In the first proceeding, the Gas Company sets forth the work it intends to performed; in the second proceeding, the parties reconcile the actual work performed against the planned work and scrutinize the reasonableness of the costs incurred before the DPU grants a gas company final recovery of the costs incurred. Prior to 2019, the recovery generally was capped at 1.5% of the gas company's revenues for the prior year. In several GSEP orders in April 2019, the DPU found it had authority to approve a cap greater than 1.5%, and held that a 3.0% cap was consistent with the intent of GSEP and reasonable under the circumstances. See, e.g., DPU 18-GSEP-04, Liberty Utilities. The DPU also has the authority to grant waivers to allow recovery in excess of the cap if it deems it appropriate.

8.2.2 GSEP provides many ancillary safety benefits.

In addition to reducing risks by reducing the amount of leak prone pipe in the system, a number of ancillary safety benefits have occurred as a result of GSEP. These include:

- Installing excess flow valves as a flow shut off device;[54]
- Moving inside meters outdoors, thereby reducing the risk associated with indoor meters;
- Updating records of the system with new information;
- Installing pressure reducing regulators at every service;
- Using plastic pipe, which generally reduces the number of gas leaks;
- Enhancing the ability to accurately locate and mark assets has increased, and effectively reduces the number of dig-ins;[55] and
- Reducing the number of low-pressure systems in the natural gas distribution system, which have their own inherent risks.

All of these additional benefits reduce risk to the public and increase public and pipeline safety.

[54] Excess flow valves (EFVs) and/or curb valves are usually installed between the gas main and the gas meter. As part of the GSEP program, these generally are being installed on every service. An EFV responds to an excessive flow of gas automatically by closing and restricting the gas flow. EFVs provide another layer of protection from the accumulation of gas in homes and businesses as the result of a gas leak or a gas over pressurization event. The National Safety Transportation Board (NTSB) began recommending the installation of EFVs in the early 1980s for schools and other places where people gather, expanded that recommendation in the 1990s to all customers, and in 2001, renewed the call for EFVs for all gas customers. (See NOPV Preliminary recommendation related to Louden County, VA incident, dated June 22 2001). Since then, many utilities have been installing EFVs. In 2017, PHMSA issued a new rule expanding the use of EFVs.

[55] A dig-in is the shorthand term for damage that can occur to pipelines during excavation. The excavation may be performed by the gas company (1st party), its own contractors (2nd party), or someone totally unaffiliated with the gas company (3rd party). Third party excavators include entities, such as the water and cable companies, as well as individuals such as your neighbor planting a new tree (3rd party). Excavation damage is the leading cause of pipeline damages across the country. Ways to lower the risk of dig-ins include encouraging calling 811 for a free locate before you dig, having up-to-date records of the type and location of assets, conducting accurate locating and marking the location of the buried pipelines, having gas company personnel present during the excavation, and requiring hand-digging within a specified distance from the asset.

8.2.3 Evaluating gas leaks discovered on gas systems provides insight on pace, trajectory and reduction of risk.

Since gas pipelines and services are buried, it can be difficult to inspect them to confirm their condition. Looking at the number of leaks discovered in a given year can act as a proxy for the condition of those assets. While leak data is a lagging indicator,[56] the Panel sees value in using it to analyze the pace and trajectory of replacement of leak prone pipe. Essentially, the questions are:

1. Is the right volume of work being done over time? (Pace);
2. Is the right work being prioritized to drive down leaks? (Trajectory); and
3. How is the potential consequence of failure considered in the decision process? (Risk Reduction).

8.2.3.1 The pace of replacement varies by Gas Company.

To answer the first question – Is the right volume of work being done over time – the Panel calculated a leak ratio for each of the Gas Companies in 2013 and in 2018. A leak ratio is calculated by dividing the number of leaks over a designated number of miles of main or number of services. Leak ratios for mains and services are reported separately. Generally, leaks on a service can pose a greater public safety concern due to their closer proximity to structures, and, therefore, to people.[57]

To conduct this analysis, the Panel sought information from each of the Gas Companies about the number of leaks *discovered* on its mains and services between 2013 and 2018, and to the extent known, the cause of the leak and whether it occurred on a main or a service.[58]

The Panel opted not to use PHMSA leak data as the basis for analysis because PHMSA data contains leaks *repaired* in a given year.[59] The number of discovered leaks is more representative of the then-current condition of the system because it reflects all leaks in a given year (even those not yet requiring repair). Knowing the causes enabled the Panel to exclude leaks arising from excavation damages, which while important for risk assessments, does not reflect the condition of the pipe.

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[56] Safety indicators often are classified into two broad groups: lagging and leading. Lagging indicators reflect safety failures, such as injuries or leaks. Leading indicators reflect the functioning of safety management systems, for example audits, inspections and hazard reports. Lagging indicators are typically easy to measure because they are discreet events that require a management response, but only provide information after the system has failed and thus drive a reactive approach to safety. In addition, lagging indicators can provide a false sense of security as the absence of failures can be incorrectly interpreted as good safety performance. Leading indicators are hard to measure, as safety is part of everyday activities, but they provide information on the level of functioning of safety systems and promote a proactive approach.

[57] The Panel learned of at least one company that does not categorize its leaks as occurring on a main or a service until an investigation is completed (sometime after the leak is graded). For purposes of this Assessment, the Panel assumed the discovered leaks of unknown origin (service or main) were most likely on the main. This is because if they had been on a service, it was more likely the leaks would have been designated as a Grade 1 leaks and repaired instead of being recorded for later action.

[58] The Panel issued Information Request #7 on September 25, 2019.

[59] Each Gas Company indicated they repair Grade 1 leaks immediately. Gas Companies differed on how long it would take to repair Grade 2 leaks (which must be repaired within a certain period) and if they would repair Grade 3 leaks. Generally, the three larger Gas Companies carry a number of Grade 2 and Grade 3 gas leaks over from one year to the next before performing a repair. This can occur for a number of reasons. For example, if a capital replacement project is planned in the near future, the Gas Company may elect to wait rather than expend O&M funds in that given year. As such, the number of repaired leaks does not provide much insight into the current condition of the system. In March 2019, the Department issued gas leak regulations that set a timeline for the repair of gas leaks. DPU 16-31-C.

The denominator in the equation can also vary. The gas industry typically calculates leak ratios per 100 miles of pipe or per 1,000 services to develop a leak ratio for each gas system, which the Panel has used here.[60] Leaks included in the ratio include those caused by any number of threats to the asset, including causes such as outside force, manufacturing defect, construction defect, equipment malfunction, and weather. However, this analysis excludes excavation damage because excavation damage is not a function of overall asset condition because it can occur on a buried asset at any given time.

After the data is analyzed and normalized, the leak ratio can be compared across time and systems to provide a better understanding of the condition of a natural gas system. A leak ratio can also be predictive of a future rate of deterioration for main and service materials. By tracking and reducing leak ratios, a gas company can replace assets and stay ahead of the rate of deterioration for a given material. Once a company is behind this rate or curve, it is very difficult to catch up as leak ratios can increase at a rate faster than the rate of replacement. Getting behind the curve can significantly increase a gas company's O&M costs (e.g., leak repairs, emergency odor call response, etc.) and has an overall negative impact on public safety, the environment, and the company.

Leak ratios should decrease over time, indicating a reduction in overall system risk and an increase in asset condition. Leak ratios on modern plastic pipe tend to range from 0.01 to 0.10 per 100 miles of mains, and are generally considered the best practice target for gas systems.[61]

The number of leaks discovered per miles of mains and number of services are set forth in Table 6 and Table 7, respectively.[62] For the larger-sized companies, the number of miles of mains with discovered leaks increased between 2013 and 2018 for National Grid and Columbia Gas, but dropped dramatically for Eversource. Even still, these rates, which are snapshots for each of the selected years, are significantly higher than leak ratios on modern plastic pipe.

Table 6: Mains – Leaks Discovered by Gas Company (2013 and 2018)

Gas Company	PHMSA ID	2013			2018		
		Total Main Miles	Main Leaks Discovered	Main Leak/100 miles	TOTAL Main Miles	Main Leaks Discovered	Main Leak/100 miles
NGC		11,021	6,335	57	11,130	8,633	78
BOS	*1640*	*6,324*			*6,370*		
ESS	*4547*	*863*			*870*		
COL	*11856*	*1,389*			*1,402*		
CAP	*2066*	*2,445*			*2,488*		
EVE	2652	3,213	1,516	47	3,292	735	22
CGM	1209	4,875	1,449	30	4,990	1,517	30

60 The other option is to normalize using only leak prone pipe as the denominator, which would then exclude those miles of pipe that may have already been replaced with more modern plastic main and likely result in a higher leak ratio. The benefit of using all pipe is more readily-comparable leak ratios in the Northeast and US.

61 This range is for segments of plastic pipe. See Appendix E for charts showing national leak ratios and leak ratios for a representative gas company that has replaced about half of its pipe with modern plastic pipe.

62 The Panel did not request that the discovered leak data be provided broken down by the four companies in National Grid.

Gas	PHMSA	2013			2018		
LIB	31770	609	325	53	619	292	47
BER	1344	759	253	33	761	185	24
UNI	5200	275	173	63	273	111	41
BLA	1504	51	0	0	55	0	0
HOL	7330	184	75	41	185	58	31
MID	12444	103	6	6	107	3	3
WAK	22035	84	63	75	88	50	57
WES	22511	207	49	24	212	41	19
MA	MA	21,383	10,244	48	21,712	11,625	54

Table 7: Services – Leaks Discovered by Gas Company (2013 and 2018)

Gas Company	PHMSA ID	2013			2018		
		Total Number of Services	Service Leaks Discovered	Service Leaks/1k Services	Total Number of Services	Service Leaks Discovered	Service Leaks/1k Services
NGC		720,001	2,466	3	761,382	2,371	3
BOS	*1640*	*490,951*			*511,285*		
ESS	*4547*	*42,887*			*52,677*		
COL	*11856*	*74,672*			*78,433*		
CAP	*2066*	*111,491*			*118,987*		
EVE	2652	195,608	898	5	204,947	460	2
CGM	1209	260,097	2,905	11	273,847	1,515	6
LIB	31770	35,659	47	1	36,828	47	1
BER	1344	32,399	54	2	32,247	63	2
UNI	5200	10,949	359	33	11,070	289	26
BLA	1504	1,292	14	11	1,470	32	22
HOL	7330	7,771	50	6	8,477	39	5
MID	12444	4,517	34	8	4,853	13	3
WAK	22035	4,914	20	4	5,033	23	5
WES	22511	8,362	11	1	8,628	35	4
MA	MA	1,281,569	6,858	5	1,348,782	4,887	4

Table 8: Comparing Progress of Replacement of Leak Prone Mains and Services (Based on Rate of Replacement from 2013 to 2018)

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Service Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (based upon current pace)
NGC	-	15% reduction 3,634 to 3,082 (552)	15% reduction 129,971 to 110,281 (19,690)	2046
BOS	*1640*	*13% reduction 3,230 to 2,806 (423)*	*14% reduction 114,663 to 98,291 (16,372)*	*2051*
ESS	*4547*	*13% reduction 103 to 90 (13)*	*15% reduction 4,965 to 4,204 (761)*	*2052*
COL	*11856*	*16% reduction 181 to 152 (29)*	*19% reduction 5,759 to 4,641 (1,118)*	*2045*
CAP	*2066*	*72% reduction 121 to 34 (87)*	*31% reduction 4,584 to 3,145 (1,439)*	*2020*
CGM	1209	39% reduction 1,023 to 623 (400)	28% reduction 48,330 to 34,613 (13,717)	2026
EVE	2652	16% reduction 1,133 to 955 (178)	27% reduction 39,077 to 28,492 (10,585)	2045
BER	1344	41% reduction 139 to 82 (57)	57% reduction 6,067 to 2,612 (3,455)	2025
LIB	31770	23% reduction 229 to 175 (54)	28% reduction 13,711 to 9,926 (3,785)	2034
UNI	5200	36% reduction 78 to 50 (28)	44% reduction 3,559 to 1,979 (1,580)	2027
BLA	1504	N/A	N/A	N/A
WES	22511	19% reduction 40 to 32 (8)	36% reduction 1,454 to 928 (526)	2039
HOL	7330	9% reduction 57 to 52 (5)	54% reduction 2,302 to 1,065 (1,237)	2070
MID	12444	36% reduction 12 to 7 (4)	28% reduction 245 to 177 (68)	2027
WAK	22035	32% reduction 34 to 23 (11)	39% reduction 1,377 to 835 (542)	2029
MA Average		**20% reduction 6,379 to 5,082**	**22% reduction 246,093 to 190,908 (55,185)**	**2038**
MA		20% reduction 6,379 to 5,082 (1,297)	22% reduction 246,093 to 190,908 (55,185)	2038
NE		20% reduction 40,285 to 32,124 (8,162)	27% reduction 1,522,784 to 1,111,355 (411,429)	2038
US		18% reduction 91,504 to 75,330 (16,174)	20% reduction 3,680,943 to 2,929,137 (751,806)	2041

Comparing the miles of main or number of services replaced from 2013 to 2018, Table 8 provides some insight as to the pace or volume of replacing leak prone pipe under GSEP to date.

Assuming the pace remains the same in future years, it appears Massachusetts is behind the pace needed to meet the 20-year timeframe envisioned in the plans originally filed under GSEP.[63] More particularly, and assuming the pace of renewal over the last five years remains roughly the same in the future,[64] it does not appear that National Grid, Eversource, and Liberty are on the pace to meet the 20-year timeframe envisioned under GSEP.[65] Although not subject to GSEP, Holyoke and Westfield also seem to be behind. The pace for other mid-size and smaller Gas Companies indicates progress is being made. For those companies with less than 100 miles of leak prone pipe remaining,[66] replacement of leak prone pipe appears quite feasible[67] within a much shorter period (e.g., five years).

8.2.3.2 The trajectory of the work varies by Gas Company.

To answer the second question – Is the right work being prioritized to drive down leaks –the Panel also analyzed the discovered leak data in Table 6 and Table 7 to provide an indication as to whether or not the replacement effort under GSEP is having a positive impact on reducing the risk of gas leaks on a given gas system. This provides insight as to whether the right mains and services are being chosen for replacement, and if the work being performed by each Gas Company each year is keeping up with the amount of natural deterioration of the system.

Conducting this analysis requires a more in-depth look at the location and causes of the leaks to establish a trend line. The results of this analysis for each Gas Company are set forth in the Gas Company Snapshots in Appendix B.

In reviewing the leak trend results presented above, Eversource stands out for the drop in discovered leaks between 2013-2018. Although their pace of replacement is behind, these results indicate Eversource has prioritized replacing the right pipe to achieve such a significant reduction in its leak rates.

8.2.3.3 Reduction of risk may need additional focus at the Gas Companies.

To answer the third question – How is the potential consequence of failure considered in the decision process –the Panel considered the work observed during the field visits. Based on that work, it appears Gas Companies may not be tackling sufficiently difficult GSEP projects early enough in the process. Much of the work the Panel observed in 2019 was in suburban locations. Generally, the Panel would expect replacement projects to be prioritized based on reducing risk in locations

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[63] This observation is based on five years, or 25% of the 20-year plan, elapsing without 25% of the work having been completed. During the Snapshot Review Process, several Gas Companies and the DPU indicated that the pace of replacement over the last five years may not be reflective of the future planned pace. When the plans were designed to meet the 20-year goal under GSEP, many of the Gas Companies indicated they intended to start out at a lower rate of replacement and ramp-up the pace of the replacement program over the first five years of the program.

[64] There is significant variability in how much main pipe can be replaced on any given day. In locations like downtown Boston, the rate of main replacement could be as little as 20-30 feet per day. Whereas replacement in suburban or rural areas can reach between 200 and 300 feet per day.

[65] If the future pace remains the same as the pace in the first five years, the of completion for main replacement for National Grid, Eversource and Liberty is projected to be 2046, 2045, and 2034, respectively.

[66] This is true for all Gas Companies except Columbia, Eversource, National Grid, and Liberty.

[67] This assumes appropriate support from all Stakeholders to reduce the risk posed by leak-prone pipe and a corresponding effort to ensure the availability of appropriately trained and qualified resources to execute the work safely.

where the risk is highest. Generally, this is in cities, where there is an abundance of hard surfaces and high-density housing.

As illustrated in Figure 3, particularly difficult projects in densely-populated locations are those for which permitting and construction is most difficult and costs are likely to be higher.[68] They also likely correspond to areas in which the number of leaks are greater and the potential adverse impact to the public is higher.[69]

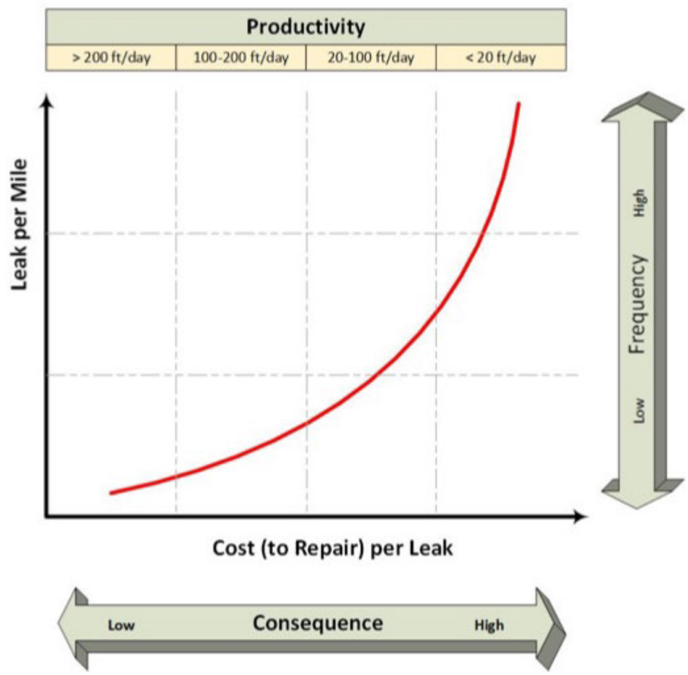

Figure 3: More Costly Projects Tend to Reduce Higher Number of Leaks

8.2.4 Leak ratios at Gas Companies are higher than the national average for mains but not for services.

To provide perspective on leak ratios for the Gas Companies as compared to gas companies across the nation, the Panel also calculated a national average of leaks using PHMSA data based on the number of leaks repaired.[70] The leak ratios at each of the Gas Companies are higher than the

68 For example, the Panel observed an Eversource job near MIT in which the contractor was able to excavate less than 20 to 30 feet per day in a complex area of buried infrastructure (e.g., steam line) using a vacuum truck.

69 PHMSA generally considers all areas along distribution pipelines as likely to have high consequences in the event of a failure, but business districts, with a higher level of hard surfaces, are generally considered to present a higher risk because if gas were to leak it has fewer opportunities to escape to the atmosphere and more opportunities to migrate under the hard surfaces into other buildings.

70 As discussed in Appendix E, these leak ratios are calculated based on leaks reported to PHMSA from 2013-2018. These data likely contain some unknown number of leaks discovered in earlier years that remain *on the books* over time. This is different than the data the Panel relied upon when calculating leak ratios for each Gas Company, which only reflects leaks *discovered* in that period. Like the data used to calculate the leak ratios for the Gas Companies, the national leak data excludes leaks caused by excavation because such leaks do not reflect the condition of the assets. Consequently, while the leak ratios in Appendix E may contain some variation in absolute values, the Panel has confidence that the ratios therein provide the correct order of magnitude for a meaningful comparison with the Gas Company leak ratios.

national leak rate for mains, but not for services. As shown in Table 9 and discussed more fully in Appendix E, the normalized average national leak rates on:

- Mains is 8.00 per 100 miles; and
- Services is 5.00 per 1,000 services.

In addition, the Panel elected to analyze the leak ratios at a Representative Gas Company, a gas company outside of the Commonwealth that has been actively replacing leak prone pipe on its mains and services since the 1980s. As of the end of 2018, the Representative Gas Company's gas distribution system is comprised entirely of plastic and protected steel assets – with no pipelines installed earlier than 1950s. The leak ratios in Table 7 demonstrate how effective pipeline renewal programs can reduce risk and help manage this aspect of public safety, customer satisfaction, and environmental issues over time.

The comparison of leak ratios from each individual Gas Company, the national industry, and the Representative Gas Company is set forth in the Gas Company Snapshots in Appendix B.

Table 9: Comparison of Leak Ratios for Mains and Services (2013 and 2018)

Entity	2013		2018	
	Mains	Services	Mains	Services
Massachusetts	34.88	5.10	33.84	3.45
Northeast	26.44	3.69	25.73	3.33
National Average	9.85	4.27	8.01	5.01
Representative Gas Company	1.35	0.11	0.69	0.14

8.2.5 Other pipe types with elevated risks may warrant inclusion in GSEP.

GSEP's definition of leak prone pipe be may be too narrow from a risk assessment perspective. Other pipe types may warrant inclusion in GSEP because they may age at an unknown rate, present a higher level of leaks, or both, or have other elevated risks. For example, such pipe types include, but may not be limited to:

- Aldyl-A plastic pipe (typically pre-1973) has experienced higher failure rates;[71] and
- Pipe installed before 1970 that presents an elevated risk. This pipe generally presents a different manufacturing and construction risk because it was installed before the Federal regulations enacted in 1971.[72]

[71] When there is sufficient evidence to demonstrate Aldyl-A pipe is leak prone, the DPU has found it eligible infrastructure to include in GSEP. See, e.g., DPU 18-GSEP-04, Liberty Utilities (holding that all Aldyl-A pipe installed prior to 1985 is eligible infrastructure under GSEP). That said, Aldyl-A is not included in the definition used in this Assessment as leak prone pipe because it is not discernable from the PHMSA-data.

[72] For example, Federal regulations require steel pipe to be of a certain strength and chemistry. Plastic pipe must be of a certain density with only a certain amount of foreign matter permitted in the pipe walls. These standards give the pipe walls more strength and resiliency, and make it less likely they will develop leaks over time. Likewise, construction techniques have changed. Welding and fusion standards were established. Coating the steel pipe and protecting it with cathodic protection to reduce corrosion became the norm under the regulations. In addition, construction techniques – such as required depth-of-cover and the type of backfill required –were standardized.

These appear to fit within the aging or leaking natural gas infrastructure that GSEP envisioned would be replaced in the interest of enhancing public safety.

8.2.6 Benefits of GSEP must be balanced with potential downsides.

8.2.6.1 GSEP work also increases risk because of the live gas work required.

Despite all of these safety benefits of increasing the work under GSEP, the Panel also observes that any time a Gas Company undertakes any type of live gas work, it inherently adds risk into the system. A gas company can manage this risk provided it has the appropriate personnel, processes, and procedures in place, follows the procedures, and controls for distractions. However, it is infeasible to reduce the project execution risk to zero.

8.2.6.2 The intense focus on GSEP may distract from focusing on other priorities.

The Panel also observes that the intense focus on GSEP and the replacement of leak prone assets can distract from managing other priorities (e.g., threats to pipeline integrity). For example, these threats could include:

- Excavation damage caused by a dig in; and
- Cracking caused by natural forces such as frost heave during winter.

8.2.6.3 Increasing the pace of replacement under GSEP is constrained by a number of factors.

Increasing the pace of replacing pipe under GSEP would result in an overall reduction of those risks arising from leak prone and pre-1970s pipe; yet, doing so appears to be currently constrained by several factors. Prior to increasing the pace of replacement, certain constraints need to be resolved such as:

- Confirm that increasing the pace can be done safely;
- Confirm availability of resources to acquire materials and complete design work in a timely manner. This may especially be an issue if the new requirement that a Professional Engineer (PE) stamp certain projects is interpreted to require a PE involvement in every GSEP project;
- Develop the availability of a qualified and competent (not *just* certified) construction workforce;
- Resolve state and local requirements that limit the amount of construction within their jurisdictions. These include the:
  - Ch. 90 paving requirement;
  - Construction moratoriums between November and April;
  - Prohibitions on use of steel plates to cover excavations after a specific date;
  - Societal impacts of increased construction on citizens; and
  - Availability of police for traffic control duty; and
- Address the GSEP revenue cap, which limits Gas Company recovery for costs.[73]

[73] See the discussion in Section 10.1.11. The DPU raised the revenue cap, from 1.5% to 3.0% in its GSEP orders issued in April 2019.

8.2.7 GSEP rate recovery process consumes significant resources.

The GSEP rate recovery process generally seems to work for all involved. The Panel observes the regulatory process for GSEP rate recovery consumes significant resource time at Gas Companies, the DPU and AG office. Streamlining the effort involved for all participants, especially given the five years of history in the program, could reduce the resources expended.

8.3 Analysis of PHMSA Incident Data

Gas distribution companies are required to report[74] certain, more serious, incidents to PHMSA.[75] These PHMSA-reportable incidents do not include all events that give rise to potential safety concerns.[76] For instance, they do not include all gas leaks or all over-pressurization events (of low- or high-pressure systems) if the events do not result in the minimum specified consequences.[77] A review of the PHMSA incident data from 2010 to 2018[78] from the Gas Companies in Massachusetts, the Northeast,[13] and across the US[79] forms the basis of the observations in sections 8.3.1 to 8.3.2.

8.3.1 Massachusetts PHMSA-reportable incident rate is about 1.5 times higher when compared to the US

Massachusetts PHMSA-reportable incidents is about 1.5 times higher from 2010 to 2018 when compared to the US. PHMSA-reportable incidents on mains[80] in Massachusetts are 0.51 per 1,000 miles, which is slightly lower than the rate for the Northeast (0.54) and higher the rate across the US (0.36). PHMSA-reportable incidents on services[81] in Massachusetts are 8.90 per million services which is higher than the rate for the Northeast (6.21) and the rate across the US (5.98). See Table 10.

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[74] 49 CFR §191.9.

[75] 49 CFR §191.3 (3) defines an incident as (1) a release of gas (and other hazardous materials) that results in (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; or (iii) Unintentional estimated gas loss of three million cubic feet or more; or (2) an emergency shutdown of an LNG facility or an underground natural gas storage facility, or (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria in (1) or (2).

[76] For example, the Panel observed two line strikes by contractors during the Field visits that raised safety concerns but did not rise to the level of being PHMSA-reportable incidents. This suggests that while the PHMSA data are helpful, the results may not reflect the true number of incidents that occur.

[77] The PHMSA definition does permit Gas Companies to report incidents that, in their judgment, are a significant incident. However, as discussed in Section 9.5, Gas Companies may be underreporting such incidents.

[78] In 2010, PHMSA changed its form for reporting incident data, making accurate comparisons of data collected before 2010 and afterwards more difficult. Accordingly, this Assessment only compares data from 2010 to 2018 (the last full year for which data was collected and published by PHMSA before the date of this Final Report).

[79] For purposes of the PHMSA incident database during this period, the US is comprised of the 49 states/territories that reported incidents. Maine, Vermont and Puerto Rico did not report any incidents from 2010 to 2018.

[80] For this analysis, incidents on mains include PHMSA incident data categorized as mains, farm tap meter/regulator stations and district regulator stations as these are more likely associated with mains than services.

[81] For this analysis, incidents on services include PHMSA incident data categorized as inside meter/regulator set, service riser, service outside meter/regulator sets. PHMSA also categorizes “other” incidents (about 10% of the incidents in 2018) which operators determined would not fit into any of the other categories. This is not included in this analysis.

Table 10: Rate of PHMSA-reportable Incidents (2010 to 2018)[82]

Area	Main: Incidents per Thousand Miles	Services: Incidents per Million
Massachusetts	0.51	8.90
Northeast	0.54	6.21
United States	0.36	5.98

8.3.2 Excavation damage and outside force damage are the top causes of PHMSA-reportable incidents in Massachusetts.

PHMSA relies on the gas operators to determine and report the cause of a PHMSA-reportable incident. These causes are categorized in the same category as the pipeline integrity threats discussed in Section 5.3. Table 11 shows the percentages of PHMSA-reportable incidents in Massachusetts as compared to those in the Northeast and in the US.

Table 11: Percentage of PHMSA-reportable Incidents by Cause (2010-2018)

Cause	Massachusetts	Northeast	US
Other Outside Force Damage	25%	24%	33%
Excavation Damage	25%	21%	30%
Natural Force Damage	18%	11%	7%
Incorrect Operation	18%	9%	7%
Other Incident Cause	14%	19%	9%
Equipment Failure	0%	9%	5%
Material Failure Of Pipe Or Weld	0%	6%	7%
Corrosion Failure	0%	1%	2%

The top two categories account for 50% of the incidents. Damage caused by excavating near buried pipelines remains the leading cause of PHMSA-reportable incidents across the country.[83] While the category of excavation damages includes damage from gas companies and their contractors (often referred to as first- or second-party damages), all seven incidents excavation damage incidents in Massachusetts during this time were caused by third parties. This reinforces the importance of addressing damage prevention through Gas Company and Dig Safe programs. Observations related to this issue are discussed in Section 9.1.3 (Gas Companies), Section 10.1.9 (DPU), and Section 10.3.2

[82] This incident rate spans nine years. The industry often normalizes the data over the nine years to provide an incident rate per mile-year. This was not done for the purpose of this comparison

[83] Numerous organizations have focused their attentions on trying to reduce excavation damages. These non-profit organizations trying to reduce excavation damages across industries include the Common Ground Alliance (CGA) and the Golden Shovel Association. Generally, a good starting place is adopting and following the CGA Best Practices. The American Gas Association recently released its latest publication focused on reducing excavation damages entitled “Implementing Damage Prevention in Field Operations” (2019). It recommends following CGA Best Practices and contains numerous specific proposals to improve excavation practices. Developing a damage prevention program that follows safety management principles (e.g., set guidelines/standard practices, investigate when something goes wrong, develop corrective actions and implement those actions) and using transparent and consistent metrics to set a baseline, monitoring and improving damage prevention over time are all facets of addressing this issue

(Legislation). Find related recommendations in Section 12.2 (Gas Companies) and 12.3 (Beyond Gas Companies).

The rates of incidents under Other Outside Force and Natural Force Damage largely occurred on cast iron mains and were directly or indirectly reported to cold weather (e.g., frost heave, or from snow or ice falling on and damaging meters).[84]

8.4 Pipeline Safety and Reliability During Proposed Energy Transition

8.4.1 Focus has been more on electrical power safety and reliability than on gas pipeline safety.

As discussed in the *Phase 1 Report*, it appears that many of the Governmental Agencies and Interested Parties have been more focused in recent years on promoting the safe and reliable delivery of electrical power rather than on the safe and reliable delivery of natural gas. While there may be other explanations for this confluence, the Panel identified three factors that may have contributed to the focus on electric energy rather than natural gas in recent years:

1. The robustness and steadiness of the natural gas distribution system over the years to reliably provide gas heating and energy needs for homes and businesses prior to the tragic events in the Merrimack Valley region;[85]
2. Storms in the Commonwealth that cause electric power outages have become more common. This resulted in increased preparedness of electric companies in terms of predicting the likelihood of an upcoming storm and preparations to quickly address resulting, predicted, electrical outages;[86] and
3. The role of electricity in reducing greenhouse gas emissions in energy transition planning.[87]

Overall, this focus on electrical power may have reduced the amount of focus, time, and energy spent on pipeline safety.

8.4.2 Role of reliability of gas supply in gas safety may not have been fully considered.

The pipeline safety concerns that arise when a Gas Company has an unreliable supply of natural gas may not have been fully considered.[88] If natural gas supply is disrupted for any reason – including a disruption of supply from a single source of gas or disruption in the availability of LNG -- the Gas Company would need to take emergency actions and make operational changes to manage their systems to address the lack of sufficient supply.

[84] Nationwide, 19.4% of incidents caused by Natural Force Damage were on cast iron main, and all of these occurred between December and March – with the vast majority being attributed to ground movement from cold temperatures (i.e., frost heave).

[85] There have been 28 PHMSA reportable incidents in the Commonwealth between 2010 and 2017, which undoubtedly were important and impactful to those involved, mostly affected individuals or business in a localized area.

[86] See the DPU Annual Reports for 2018 and earlier reports.

[87] Id. Over the last number of years, many resources have been devoted to analyzing the fuel shortages for electric generation.

[88] The lack of supply is at the heart of moratoriums on new services in certain service territories. Natural gas systems are designed and operated with certain capacity requirements. Serving proposed new meters without adding supply can create safety issues if the operators try to meet demand without thee additional supply needed to keep the pressures at appropriate levels.

Disruption of a single pipeline source has risks if that source becomes unavailable.[89] Depending on the circumstances, the rupture of a natural gas transmission pipeline could take the pipeline out of service for a few days, weeks, or longer.[90] After the pipeline returns to service, its capacity to provide service at the same level before the event also may be limited for some period of time.[91] During this time, despite the contractual obligation (e.g., a firm commitment) to do so, the gas transmission pipelines may not have ability to deliver gas.

In addition, although assessing LNG facilities was outside of the scope of this Assessment, the Panel observed that several Gas Companies currently rely on their LNG or propane air plants to meet a substantial portion of peak gas supply demands, even when there is no force majeure event.[92] Currently, some Gas Companies use LNG to meet up to 40% of a peak-day load. By comparison, the broad benchmark across the industry is that, generally, using LNG to meet more than 10-15% of a peak-day load is considered too high for long-term system reliability. This reliance on aging facilities to provide high percentages of peak-day load adds to supply risks for Gas Companies in Massachusetts.[93]

If a lack of supply develops from a force majeure event on a transmission pipeline or at an LNG facility, the necessity of taking such emergency actions to address the lack of supply adds risk.[94] Too, customers would lose natural gas service for some period, which depending on the time of year,

[89] For example, a rupture in an interstate transmission pipeline could curtail its ability to provide any gas supply for an extended period, while the ruptured pipe is repaired and the cause of the incident investigated by regulatory agencies. Alternatively, gas demands on any given peak day could exceed the amount of physical gas available to be delivered to supply points. Massachusetts is situated at the end of several interstate pipelines. This location makes the risk of loss of supply higher than if it were located elsewhere on the system.

[90] In the last five years, natural gas transmission pipelines in the US have experienced numerous ruptures that resulted in limited delivery capacity to the regions served.

[91] Pipelines that return to service often are required by PHMSA to do so at a reduced pressure. This results in a reduction of the amount of gas the pipeline can transport. This reduction in capacity can be in place merely during the pendency of the investigation into the cause or may remain in place for much longer periods while other remediation efforts occur. In one instance arising from the rupture on El Paso Natural Gas Pipeline in 2001, the reduction of capacity following the pipeline rupture lasted for years.

[92] LNG plants are limited both in production capacity and by the amount of LNG that can be delivered by truckload. The capacity of propane air plants, in which air is mixed with propane to produce the quality of methane used in homes and business, is also limited – both by the capacity of the facility, and by the amount of propane/air that can be injected to create the requisite gas quality.

[93] While LNG has been a reliable source for gas supply within Massachusetts in the past, the key for continued sustainable long-term reliability lies in more robust integrity management plans and continued refurbishment, upgrades and investment in existing facilities, especially considering that most have been in operation for 50 years or more.

[94] Taking action under emergency conditions increases risk. This could include losing sufficient pressures to maintain gas delivery to certain customers or portions of a town, terminating service to select customers while trying to maintain services to critical need customers, and recovering after the event. In addition, even without an emergency condition, the substantial reliance on LNG adds risk arising from the increase of trucking of LNG within Massachusetts. Estimates suggest current LNG use already adds somewhere between 4,000-7,000 LNG trucks on Massachusetts roads each winter.

could be life-threatening. Lastly, customers may not be aware of the risk nor adequately prepared to withstand the loss of gas service.[95]

DPU has extensive processes in place to confirm Gas Companies contract for sufficient "firm" supplies of natural gas to meet the needs of the citizens, especially in winter months.[96] The contracts that Gas Companies have entered into with gas transmission pipeline companies for the delivery of natural gas for "firm" transportation of natural gas, however, will not protect the reliability of supply in all instances. This is because of the difference between contractual protections and the physical nature of transporting and delivering gas.

In fact:

1. If an interstate pipeline loses its ability to deliver gas through an event of force majeure, peak demands or otherwise, there may be contractual remedies available, but gas will not be delivered; and
2. If demand for the amount of gas that can fill an interstate pipeline exceeds the supply available on the interstate pipeline, the pipeline company can reduce the amount delivered. Again, this may result in the Gas Company having contractual remedies but not having gas to deliver to customers.

For these reasons, it will be important as part of its efforts to enhance pipeline safety for the Commonwealth to provide an appropriate focus on strengthening gas supply availability in those instances in which a Gas Company relies on a single source of gas supply or is overly-dependent on LNG facilities, and while maintaining gas supply availability during the transition planning discussed in Section 8.4.4.[97]

[95] If there is a gas supply constraint, Gas Companies would need to decide where and how to curtail service. As one example, in 2014, a major mid-western gas distribution company was forced to consider curtailing gas delivery to several cities in the upper mid-west during a polar vortex event after the interstate pipeline providing gas supply to the distribution line at the border in the area suffered a failure. The distribution company undertook numerous efforts to meet demand during the outage – by asking customers to reduce thermostats, shutting off all interruptible customers, acquiring more gas flow, using backflow where feasible, and running all peak shaving facilities at maximum; yet, the company still had to consider additional curtailments. Fortunately, the interstate pipeline returned to service just hours before those the curtailments began.

[96] The DPU has a division dedicated to gas supply contracting. DOER also works with industry to ensure sufficient supplies of delivered fuels.

[97] There are a number of ways the Commonwealth can elect to address this concern. For example, the supply issue could be addressed by increasing the capacity of LNG facilities within the Commonwealth. As noted, however, this avenue presents its own challenges and potential risks.

8.4.3 Additional work remains on curtailment planning.

Based on interviews during Phase 2, it appears the Gas Companies, DPU and DOER have additional work to improve their preparation in the event of a gas supply shortage that is sufficiently serious to require curtailment of gas service.[98] DOER has responsibility to plan for energy shortages[99] and it has been coordinating with the DPU and the Gas Companies at joint meetings on this topic. Additional interagency coordination would be helpful, as would a joint mock drill with the relevant agencies and the Gas Companies to confirm that the appropriate emergency planning is in place.

8.4.4 Pipeline safety may not have been fully considered while addressing climate change.

As noted in the *Phase 1 Report*, the Commonwealth of Massachusetts leads efforts to address climate change. Additionally, many Interested Parties are focused on addressing climate change. As part of this effort, Interested Parties, including the government, private organizations, and certain individuals advocate for the need to reduce the amount of fossil fuels used to meet the energy needs of Massachusetts residents. For example, in August 2008, the Commonwealth passed the *Global Solutions Warming Act*, which requires the Commonwealth to reduce greenhouse emissions by 80% by 2050.[100]

To date, it appears the Commonwealth is in the process of developing a transition plan under which the citizens of the Commonwealth can access energy to provide necessary heating, cooling, and cooking to people in homes and businesses. In this transition plan, the safety and reliability of natural gas service during the transition away from fossil fuels may not have been a focus.

8.4.5 Tracking *Unaccounted for Gas* in the field is infeasible.

Although lost and unaccounted for (LAUF) gas is not a valid proxy for either unknown leak volumes or methane emissions,[101] certain Stakeholders have expressed both a concern about the amount lost and a desire to measure lost gas during field work.

As background, LAUF gas, as explained by PHMSA to Congress, is a combination of measurement inaccuracy within a gas system and unknown leaks; it is impossible to know the portion attributable

[98] As discussed earlier, curtailments could impact entire neighborhoods, towns, and ends of delivery lines (especially those receiving gas from low-pressure systems). Depending on the location and arrangements of vulnerable facilities (i.e., hospitals, nursing homes, day-care centers), curtailments could have serious, adverse humanitarian impacts.

[99] Chapter 25A of the *MA General Laws* generally relate to subject matters under DOER's jurisdiction. MA G.L. c. 25A, s. 8 states: "Upon issuance of such declaration of an energy emergency the Governor shall implement, at his discretion, with or without any Federal delegation, action or approval (i) such energy supply shortage contingency plans including conservation contingency plans and rationing contingency plans as have been developed by the department [DOER] and which conform to the substantive requirements of 42 USC Secs. 6261-6275 and (ii) any petroleum plan or other measures which comply with the substantive requirements of 15 USC Sec. 751-760H or successor federal legislation."

[100] The *Global Solutions Warming Act* set economy-wide greenhouse gas (GHG) emission reduction goals for Massachusetts that will achieve reductions of between 10 and 25% below statewide 1990 GHG emission levels by 2020 and 80% below 1990 statewide emissions by 2050.

[101] *Id*. *See also*, *Lost and Unaccounted for Gas by ICF International* was prepared for the Massachusetts Department of Public Utilities on December 23, 2014 and found at http://www.mass.gov/eea/docs/dpu/gas/icf-lauf-report.pdf (this document concludes that LAUF gas is not an appropriate surrogate for methane emissions).

to each.[102] LAUF is the calculation that represents the difference between the amount of gas supplied and the amount consumed. It largely arises from three main factors:

1. Measurement inaccuracies based on the pressure and temperature of gas when measured;
2. Operational factors such as meter reading not occurring at the same time or under the same operational conditions; and
3. Gas released during maintenance, construction, and emergency response efforts.

In the field visits, the Panel observed the release of gas during various maintenance and construction efforts. Gas releases generally occurred in small quantities, which were released in a way that made measuring nearly impossible (i.e., while installing a tee on a mainline). For these reasons, the Panel finds it infeasible to measure the amount of gas lost during field operations.

[102] PHMSA report on LAUF from distribution pipeline systems, provided to Congress on May 16, 2017, and mandated by Section 29 of the *Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act* of 2016, Public Law No: 114-183. See https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/17986/report-congress-lost-and-unaccounted-natural-gas-metrics-may-2017.pdf

9 Observations About Gas Companies, In General

Based on the work in Phase 1 and Phase 2, the Panel provides observations that are generally applicable to the Gas Companies[103] in sections 9.1 through 9.9.[104] The observations encompass the following topics:

- Insights from field visits (Section 9.1);
- Learning culture (Section 9.2);
- Hazard identification (Section 9.3);
- Impact of company size (Section 9.4);
- Tracking critical gas events (Section 9.5);
- Factors that may be creating a false sense of comfort (Section 9.6);
- Risk assessments (Section 9.7);
- Records (Section 9.8); and
- Emergency response (Section 9.9).

The Panel found the Gas Companies welcomed this Assessment. Discussions in early 2019 were extensive and candid. Every company attended with members of their senior leadership team and an array of management and experts to answer questions from the Panel. The Gas Companies responses to the Panel's requests for calls, meetings, and document productions throughout this Assessment, and the largely unfettered access during the field sites to company locations, work sites, and individuals, provided the Panel with opportunity to develop the observations in this section.

9.1 Field visits provided valuable insights.

Based on the field visits, which are detailed in Section 3.2.1, observations include the different perspective gained from the field, the *O&M Manual*, excavation practices, job briefs, the impact of change on jobs, the use of site-specific plans and checklists, the implementation of the PE requirement, competency of crew chiefs, use of inspectors, planning and execution challenges, and labor relations. These are set forth in sections 9.1.1 to 9.1.11.

9.1.1 Field visits revealed a different perspective than meetings or documents.

The Panel learned more about each Gas Company's operations by making site visits in the field than reviewing documents or talking to management.[105] Moreover, what was observed in the field often did not match what the Panel expected based on company presentations or the reviewed company

[103] The Panel's observations are based on the Panel's learnings, experiences, and perceptions during this Assessment. While certain Gas Companies provide examples of the general observations in this section (Section 9), each Gas Company is urged to conduct an evaluation of their own systems, practices, and processes to determine the relevance and applicability of the general observations to them.

[104] Observations specific to each Gas Company are set forth in Appendix B. Although these observations are specific to each Gas Company, the other Gas Companies may opt to consider whether any also apply in their organizations.

[105] Recall in Phase 1, Gas Company management teams made presentations to the Panel about company procedures, policies, and plans.

documents. Crews rarely, if ever, used O&M manuals to guide the actual execution of their work. Excavation practices vary widely and often appeared to be out of alignment with company or State guidance. Meaningful pre-job briefs were largely non-existent. This suggests a gap between what Gas Company management, State Agencies, and Stakeholders believe is happening in the field and what actually happens in the field.

9.1.2 O&M Manuals may be compliant, but are rarely helpful or relied upon in the field.

Most crews had copies of drawings and procedures on hand (e.g., in trucks or offices) and generally were able to access them when asked.[106] The vast majority, however, neither used nor relied upon the O&M or other written materials to perform their work. Instead, the crews largely relied on their own skills and experience, their "read of the street" expertise,[107] and their usual work practices to perform the work.

This combination of skill and experience served the crews well in performing routine tasks. The vast majority of work in the field observed by the Panel met industry standards.[108]

Observed tasks included:

- Fusion of plastic pipe joints to one another;
- Laying of fused pipe joints into the trench (with sand below, tracer wire and warning tape nearby);
- Installation of a riser and outdoor meter;
- Installation of stab tees; and
- Protection of the main plastic line or the service plastic line at the point of insertion into pipe (cast iron or steel).

Even if the crew had been inclined to regularly use the appropriate O&M manuals in the field, the procedures within them were often so general they required significant interpretation from the crew to adapt them to the site-specific conditions.[109] In fact, most Gas Company's O&M manuals appear to be written to meet compliance requirements and protect the company rather than provide clear, easy-to-follow, step-by-step guidance to field crews. If intended to provide field guidance, O&M manuals would benefit from:

- Providing more detailed information that would be useful for the practitioner to identify more precisely what and how to perform work;

[106] Several times crew members struggled to recall passwords or had difficulty accessing the O&M on the devices provided. Sometimes this was a lack of familiarity or, at times, a lack of a sufficiently strong or any Internet signal.

[107] *Reading the street* is a skill practiced by crews in the field. It means looking for and assessing all of the clues on-site about the location and possible condition of underground assets to better plan the planned work. In includes, among other things, examining the street and surrounding areas to identify the new and old marks indicating the presence of underground facilities, looking for evidence of water, sewers, or storm drains, noticing whether the pavement or grass has been disturbed, and judging the likely timing of that disturbance.

[108] The Panel did not assess if specific work tasks were compliant with any specific Gas Company's O&M manual.

[109] The variability of site conditions increases the difficulty of making the best interpretation for that job in the moment. The adoption of using site-specific step-by-step procedures for more complex work, as discussed in Section 9.1.4, would likely overcome the need for revising O&M manuals to provide more specific field guidance.

- Clarifying contents with images and lists; and
- Clarifying communications about use of, and changes to, O&M using, for instance, a rigorous management of change protocol.[110]

These changes would provide an opportunity for the Gas Companies to move beyond compliance, which can help to improve gas pipeline safety.

9.1.3 Excavation practices largely varied from Gas Company procedures.

Gas Companies, as well as the DPU and others, have undertaken numerous efforts to help manage the threat of excavation damage to buried mains and services.[111] There is room for improvement by all parties involved.[112]

During its field visits, the Panel observed both inconsistent understanding and application of a tolerance zone[113] during excavation of mains and services.[114] On three occasions, the Panel observed excavations that created a potential safety concern.[115]

[110] See Footnote 22 for a discussion of a management of change protocol.

[111] One way is participating in Dig Safe. This is a not-for-profit clearinghouse used by the Commonwealth of Massachusetts and the states of Maine, New Hampshire, Rhode Island, and Vermont. When a person calls 8-1-1 before digging or making any excavation, Dig Safe notifies participating utility companies of the plans to dig. In turn, these utilities (or their contract locating companies) respond by marking the location of their underground facilities. See G.L. c. 82, §§40 through 40E. Dig Safe is a free service, funded entirely by its member utility companies. Gas Companies also have regulatorily required public awareness programs to help inform the public of risks associated with the presence of buried gas pipelines. As noted in the *Phase 1 Report*, Gas Companies' public awareness programs are compliant with regulatory requirements but may not focus on ensuring efficient and effective communication with the communities they serve.

[112] The DPU and Massachusetts legislators have opportunities to continue to help improve Dig Safe too. See Section 10.1.9 and Section 10.3.2, respectively.

[113] The practice of hand-digging around live assets is an essential control in preventing excavation damage. A tolerance zone is that area surrounding the pipe – on both sides, on top, and below -- in which company procedures require hand-digging to protect the asset from damage. While each Gas Company sets the extent of the tolerance zone based on its own risk management analysis, the pipeline industry standard usually requires hand-digging within 18 inches of the asset.

[114] For example, the Panel observed variances between how far away from assets the field crew thought hand-digging was required versus the distance specified in company procedures. Some thought the tolerance zone would be a foot or more away, others 2 to 3 inches. This varied between Gas Companies but few Gas Company field operations personnel had a precise and consistent answer about the Company expectations in this regard. One operator stated he could brush the back of the backhoe's bucket along the top of the cast iron pipe. See Appendix B.8.3, National Grid (NGC-15). There also was variance as to when the field crew believed company procedures allowed them to safely return to using the backhoe to continue the excavation. The Panel observed a widespread practice among all Gas Companies: hand-digging only until the asset became visible and then returning to using mechanical means to excavate next to the exposed pipe. Often, the crew would place the shovel face against the asset, and then return to using the backhoe, brushing the back of the shovel blade with the backhoe bucket erroneously believing the shovel protected the pipe from damage from the backhoe.

[115] Two of these involved the use of mechanical means close to live mains and services. See Appendix B.11.3, Westfield and Appendix B.4.3, Eversource. The third involved a failure to mark the live service during a service line replacement. See Appendix B.10.3, Wakefield. On each occasion, the Panel acted in accordance with its Guidelines for Engagement and asked each Company to disclose the observation to the DPU for handling by the DPU outside of this Assessment.

The Panel issued a Safety Case to the Gas Companies on September 9, 2019.[116] In this Safety Case, the Panel recommend Gas Companies undertake efforts to:

- Understand what was occurring in the field;
- Learn why deviations were occurring;
- Review their own O&M manuals; and
- Undertake appropriate actions, including communications to field personnel about the company's expectations regarding the tolerance zone for excavation using mechanical equipment near live gas mains and services.

Observations in the field following the issuance of the Safety Case indicate Gas Companies must continue to focus on understanding and improving Dig Safe practices in the field.

More broadly, each Gas Company has the opportunity to move its Damage Prevention Program beyond compliance. Managing 8-1-1 calls and ensuring accurate locating and marking of facilities is an essential and foundational part of damage prevention. Like other mission critical programs, damage prevention programs must consist of a broader understanding or risk, a process to investigate mis-marks or excavation damages, development of lessons learned, and tracking of implementation of changes based on the lessons.[117] For example, treat asset damage and near misses seriously and as an opportunity to understand what went wrong in the organizational process. Using this strategy will assist Gas Companies in preventing future incidents.

9.1.4 Meaningful pre-job briefs were largely non-existent.

Meaningful pre-job briefs[118] were largely non-existent in practice. A good job brief engages the crew in a process hazard safety analysis by providing the opportunity for the crew to consider the site-specific circumstances and discuss the hazards that might occur.[119] Instead, the job briefs appear to have evolved into an administrative requirement in the field and, generally, are managed as such.

[116] See Appendix H, Safety Case Issued to Gas Companies. Having observed such a variance in excavation practices across several Gas Companies, the Panel undertook a review of certain Gas Company's O&M manuals, industry guidance, and the language in the MA Dig Safe laws and regulations. In many cases, there appeared to be an unintended ambiguity in the language concerning the application of the safety zone or tolerance zone that left the meaning of the tolerance zone and its application unclear.

[117] This process is sometimes referred to as conducting a root cause analysis (RCA). A true RCA is a formalized objective process that is a fact-based and method-driven. To be effective, it must incorporate steps in each of the *plan-do-check-act* phases. Oftentimes, Gas Companies and others in the industry use the phrase inappropriately to describe what they can readily observe as the direct cause of the incident (e.g., the bucket of the backhoe struck the buried pipe so the *root cause* must be operator error). As discussed further in Section 9.2 and Footnote 147, for an RCA to become a meaningful exercise in organizational learning, it must be objective, thoughtful, and transparent.

[118] Also known as a "tailgate," a pre-job briefing ideally provides a pause before the work begins, when everyone at the work site engages in a discussion during which site-specific work information is discussed.

[119] See Section 9.3 regarding discussion of hazard identification process.

While a handful of the observed job briefs were well done,[120] the vast majority were not. This was true whether:

- The job brief was provided in the office or in the field; and
- It was at the start of the work day or when Panel arrived at a site.

Often, the Panel observed work commence when there had been no job brief at all. Individuals arrived at the work site and began to perform the job tasks they had performed the day before. When it did occur, most job briefs consisted of a general statement of the work to be performed for the day ("we're going to lay main starting at the corner") and an identification of risk present in most of the work performed ("when excavating you could hit a live gas line" or "it is hot out so stay hydrated"). On occasion, the job brief included a more thoughtful analysis by the crew chief of the hazards that could be encountered.

The requirement to perform a job brief and complete the requisite paperwork, generally, was not lost on field personnel. When asked about the job brief, it was not unusual for individual crew members to provide the Panel with inconsistent answers about whether a job brief had occurred, and if so, where, when, or what was covered at the job brief. At each job site, however, the Panel would be asked to sign the job brief paperwork. While the Panel asked for information about the job and its hazards before signing the job brief paperwork, Gas Company supervisors, inspectors, or other visitors to the site routinely signed the job brief paperwork without discussing job and on-site hazards.

9.1.5 Unintended consequences of field changes went mostly unrecognized.

The impacts of changes in the expected state, pace, or process of the work flow presented unique challenges on the work site that largely went unrecognized by crews. On each occasion of change, a crew reacted to the change but without stopping to consider how the change might affect the work flow.

In one instance the Panel learned about during a field visit,[121] a truck load of gravel was rejected by an on-site inspector. Rather than stopping work to allow the truck to take away the rejected gravel and then return later with new gravel, the work continued but with a different order of work processes. Subsequently, the crew who was working outside of their normal pattern for loading spoils and unloading gravel, inadvertently struck an electrical line.

This disruption of work flow – regardless of the reason for it – introduced risk into the process that went unrecognized and unaddressed by the crew. The Panel found this to be true in a host of circumstances throughout the Assessment even though most companies have a Stop Work policy[122]

[120] The Panel received outstanding job briefings with excellent hazard identification on three main replacement job sites:
1. One at a Berkshire job site near a river – see Appendix B.1.6, Berkshire;
2. One at an Eversource job near MIT – see Appendix B.4.6, Eversource; and
3. One at a National Grid job site on Cape Cod – see Appendix 6.c, National Grid.

[121] See Appendix B.8.3, National Grid. While the crew explained what had happened during an earlier portion of the job, their concerns over the inspector actions in the narrative missed the essential lesson, which was: every time there is a change in the anticipated flow of work, risk increases and actions need to be taken to mitigate those increased risks.

[122] As discussed in Appendix A.5.4, workers are often encouraged to stop work if they observe something occurring on the worksite that appears to be unsafe. Often, management will cite the Stop Work policy as the last-best defense against a catastrophic event. While this may be factually accurate, it may be unfair to place such a burden on individual workers when reaching that point is likely an organizational failure.

to address imminent safety hazards. The Panel observes, however, that implementing a different policy that is similar to the Time Out For Safety program described in Appendix A.5.4, would be beneficial. In the Time Out For Safety program, Gas Companies create a process for workers to call for a time-out when there has been an unexpected change to the planned workflow or if there is a safety concern. The wider range of reasons for calling a time-out makes it easier for workers to use this process. This *time-out* provides a pause in which the crew could consider the change and develop a plan on how to adapt to that change.

9.1.6 Field activities with elevated risks benefited from site-specific work plans and checklists.

The Panel observed crews undertaking tasks that were more complex or undertaken less frequently than those daily work tasks identified in Section 9.1.3. Those crews using site-specific checklists largely agreed that working from a specific check list, similar to a pilot's pre-flight checklist, had several benefits when the task involved complex or infrequently performed projects. These include:

- Sequencing tasks in the correct order for the job;
- Having someone else prepare and review the checklist for completeness;
- Having the benefit of another person reviewing the task list when at the site if the checklist was completed onsite by another crew member; and
- Avoiding the need to use or interpret the *O&M Manual* in the field.

The checklists used by National Grid's contractor crews were particularly well done and well used for the complex tasks they undertook.[123]

Conversely, at one work site, a Gas Company supplied a detailed checklist to the crew, but rather than checking off the items as each step was completed, the inspector indicated he would check off all of the items at the end of the day.[124] This highlights that, not only is it necessary to supply the appropriate tools to reduce risk, it is also necessary to confirm tools are being used as intended.

Based on observations in the field, a site-specific work plan or checklist may be more effective, if they are limited to complex or infrequently performed tasks that have the potential for elevated risk rather than for everyday tasks.[125] For example, tasks that would fit into this category include, and are not limited to, those listed in Table 12.

[123] For instance, the Panel observed one crew undertaking a replacement and tie-in of a dual-pit district regulator station in which the National Grid checklists were well defined, clear, and used by the crew. The procedure was several pages long with numerous steps and tasks on each page. Many of the tasks required the crew to call into Gas Control to obtain permission to proceed to the next step. The crew found this step particularly helpful in providing another layer of attention to the project steps. Each step required the crew chief's signature. See Appendix B.8.3, National Grid. Similar useful site-specific work procedures were used at other National Grid work sites.

[124] See Appendix B.3.3, Columbia Gas. In this example, not only did the Columbia Gas inspector fail to use the checklist as intended but he briefed the crew on a purge plan that the inspector had reason to know, via an email the night before that he acknowledged reading, was in the process of being modified by engineering. This highlights the need for fully engaged, qualified, and knowledgeable inspectors on site.

[125] The exception may be for new or more inexperienced employees who may welcome a check list for every task being undertaken.

Table 12: Field Activities with Potential for Elevated Risk

Field Activity	Description of Activity	Potential for Elevated Risk
Purging	Purge air/gas from new or abandoned pipe.	Inconsistent/incorrect order of steps taken, insufficient mitigation for static ignition, insufficient monitoring of gas mix, and locating purge pipe without considering protection of employees and public.
Tie-in new pipe to live pipe	Tie-in new construction to existing systems. Includes interconnects with other systems, and extending, looping or renewing pipelines. Includes over-pressure protection.	Tie-in of systems with similar or different pressure systems; mitigating potential outages, over-pressure situations and preventing accidental ignition.
Grading and responding to leaks	Responding to and investigating inside and outside odors/leaks. Includes grading, monitoring/protecting the public.	Inconsistency of grading, incomplete investigations without eliminating potential migration paths, inconsistent direction on when to evacuate buildings, and monitoring after repair to confirm resolution and safety.
District Regulator changes or non-routine maintenance	Routine and non-routine non-meter regulator inspections and maintenance. Includes over-pressure protection.	Incorrect steps due to working with differing pressure systems and different designs, and less frequently performed tasks. Understanding of over-pressure protection. Sufficient monitoring, identification and mitigation of over-pressure events when they occur.

In addition, interviews during the field visits indicated effective work plans or checklists have the following characteristics:

- Site-specific (this may mean someone has to visit the site to identify requirements);
- Include the order or sequence of the major tasks to be accomplished;
- Require a checkmark (or another notation) before proceeding with the next task;
- Detailed but not too granular;
- Include accountability for the completion of the tasks in the correct order or sequence; and
- Consult with Gas Control (for those systems with Gas Control) on certain tasks that may impact system pressures.

The Panel also observed there were some tasks undertaken by crews that might not warrant a site-specific work plan being developed, but might benefit from additional vigilance above and beyond the customary work. Types of additional vigilance might include:

- Providing the crew more time to complete the job;
- Confirming a supervisor, company inspector, or both are present for the entire job;
- Providing additional training before the work; and
- Providing quality control checks during and after the work.

Examples of tasks that may require a need for increased vigilance are set forth in Table 13.

Table 13: Candidates for increased Vigilance

Tasks	Description of the Tasks	Potential Reasons to Increase Vigilance
Leak investigations	Responding to and investigating inside and outside odors/leaks. Includes grading, monitoring/protecting the public.	Inconsistency of grading, incomplete investigations without eliminating potential migration paths, inconsistent directions on when to evacuate buildings, and monitoring after repair to confirm resolution and safety.
Cross bores	Installing mains or services using horizontal directional drilling (HDD) or other drilling process.	Not recognizing when sewer and gas lines might be in similar depth zone; no positive affirmation of no cross bore.
Damage prevention	Locating and marking underground utility lines prior to excavation activity.	Insufficient/incomplete data, lack of experienced personnel for tricky or unknown locates, insufficient clarity on program requirements (includes use of hand tools vs mechanical tools), including methods, investigations and corrective actions. Late locates. Not standing by and protecting key assets when third parties excavate nearby.

9.1.7 Implementation of Professional Engineer requirement is still evolving.

The Commonwealth's new law[126] requires that a PE review and approve plans for natural gas pipeline work that might pose a material risk to the public. In addition, the Final Report from National Safety Transportation Board regarding the incident in the Merrimack Valley in September 2018, recommends that other states which currently exempt gas engineering from the PE requirements remove the exemption.[127]

The safety value and benefits of this legislation should be further reviewed, and all options considered.[128] The Panel observed the use of PE-stamped drawings at many field sites. The PE stamp appears to add value in complex projects by providing another layer of review, and creating a pause in the work to consider options.[129]

[126] Following the tragic incident in the Merrimack Valley Region, the National Safety Transportation Board (NTSB) issued its Accident Report (NTSB/PAR-19/02, PB2019-101365, adopted September 24, 2019. It adopts the NTSB's preliminary recommendation from November 15, 2018, that "it is critical for an engineer with appropriate qualifications and experience to review engineering plans." Based on the NTSB preliminary recommendations, the Massachusetts Governor signed the bill into law. See Chapter 339 of the Acts of 2018 in January 2019. Subsequently, the DPU issued initial guidance to Gas Companies on how to implement the law, and has opened a rulemaking process DPU Docket #19-34 to develop the regulations and guidance to the Gas Companies.

[127] See NTSB Final Report, Overpressurization of Natural Gas Distribution System, Explosions, and Fires, Merrimack Valley, Massachusetts, September 13, 2018, NTSB.PAR-19-02, PB2019-101365.

[128] The DPU is currently considering such options in DPU Docket #19-34. On October 11, 2019, it proposed a strawman proposal and is seeking comments from various stakeholders. Several Stakeholders, including the AG's office, support a technical conference to discuss the matter. Given the complexity of the discussion, the Panel believes a technical conference may be helpful.

[129] For example, in one instance, the on-site fabrication of piping did not match the PE-stamped design drawings of a new district regulator station. While work stopped, the Gas Company's Gas Supervisor (on-site to accompany the Panel) reached the PE after several attempts. The PE – who was away speaking at a professional seminar – worked through the issue and agreed the fabrication could work but drawings would need to be re-done. The Gas Company opted to re-fabricate the piping. See Appendix B.11.3, Westfield.

On other occasions, the value of the PE stamp was less clear. The Panel was made aware of several instances in which the need for the PE stamp to review a minor change added days to the construction process, resulting in a stop-start-stop-start cycle that increases risk but with little benefit.[130] In several instances, the Panel observed PE-stamped drawings that contained errors.[131]

While a PE stamp can add value, it does so only if the PE has the right information[132] and the right experience.[133] The PE needs access to the relevant information, and needs to have an intimate knowledge of the gas system itself. This may require PEs to be present in the field as they work on project drawings. The PE may also benefit from involving and learning from the Gas Company's chief engineer.

Based on the observations, tasks that would benefit from having a PE review are complex projects that involve more than one more routine task, multiple pressure systems or a variety of assets. For example, a combination of tasks that individually may be routine, but when combined present challenges to integration in the correct sequence. This might include, for instance, a tie-in of one main to another, a gas purge, and an upgrade in the pressure for the system. Another example is an integrated system (multiple feed points) where new pipe is being installed or one of the feed points modified. In both instances, a PE can weave together the required sequencing of steps from each task to ensure safe execution of the overall project. Regardless, good process includes communication and review between the PE and the Operations team that is completing the work in advance of the work. This allows solid understanding of the potential hazards, time to make changes to drawings or the procedure, and, overall, improves performance of the job while reducing risk.

9.1.8 The crew chief's competency and leadership skills are essential to safety.

The level of competency and focus on safety at any given job site appeared directly linked to the competency and leadership of the crew chief. A competent strong crew leader makes a stark difference in the atmosphere of the work site, the work production, and the level of concern about process and personal safety at the site. Likewise, crews working for a competent crew chief expressed more understanding of the task requirements, more awareness of the hazards present, and the plan to mitigate those hazards.

Common characteristics of the exercise of authority that marked strong crew chiefs include:

- Stop work and greet visitors to the site immediately upon their appearance on the site;
- Engage with public on the site;

[130] The PE-stamped drawing did not precisely match the assets already in the ground. The crew halted construction for several days while the information about the current assets in the ground made its way back to the PE. The drawing was revised to add those assets, which were not impacted by the work, and no other changes were made.

[131] In one instance, the PE-stamped drawings and step-by-step procedure underwent six revisions – with some revisions made on the same date – and several versions to correct an error in the last version. As it was about to be implemented, a field crew chief identified missing assets that would be affected during the purge process, resulting in yet another revision. See Appendix B.3.3, Columbia Gas. In another instance, a PE-stamped drawing contained intake pipe that couldn't possibly exist in that location given the gas flow. See Appendix B.8.3, National Grid.

[132] PEs need to know the gas system, gas system configuration, location of buried infrastructure, and the operation of the gas system to create accurate drawings and processes. This information is often acquired from Gas Company records, which are not always accurate. Increasing the accuracy of records will improve PE drawings. Also having the PE assigned to the project make field visits as part of the process, especially for complex projects, would add value to the process.

[133] PEs are licensed in fields of expertise that are general (e.g., a chemical or mechanical engineer). There is no PE license specifically for gas pipelines.

- Explain the scope of the work, the hazards present and the expectations and limitations for visitors and, after explaining those factors, require signatures to demonstrate the visitor's understanding of the same;
- Familiarity with and use of the drawings and procedures, and "reading of the street";
- Understand how the scope of work fits into the pipeline system as a whole;
- Demonstrate inquisitive attitude and openness to discussion; and
- Encourage crew members with strong work and problem-solving skills.

While the crew chiefs observed by the Panel spanned the continuum – from strong competent crew chiefs to those with less experience and confidence – the Gas Companies appeared to do a good job of matching crew skill sets with the complexity of the job. The Panel observed the most complex work sites were most often run by the most competent crew chiefs and crews.

9.1.9 Experienced and engaged Gas Company inspectors increased productivity and safety.

Gas Companies can benefit from increasing the number and frequency at which they use company inspectors for work performed in the field. This is true for company inspection of both employee and contractor work. The inspectors should be independent from the personnel performing the work. This independence may be accomplished by establishing a quality assurance/quality control (QA/QC) department for the gas company inspectors that is under separate leadership than the workforce performing the work. The inspectors also must have sufficient experience and training, and bring a commitment to being engaged in the work – to effectively provide the work site with an additional set of eyes and mind to think through the challenges the Panel observed at every work site.

Regarding the ratio of job sites per inspector, the Panel observed that one company inspector at one job site enabled the inspector to more effectively perform oversight and guidance, especially if the job was somewhat complex. One inspector over two sites was workable if the job sites were located nearby and the jobs were straightforward. Inspectors covering more than one or two sites generally were not able to be present during each stage of the work being performed to be sufficiently informed about the challenges present at each site or to provide the value an experienced and engaged inspector brings to a job site. Specifically, that is to resolve questions, provide guidance, be the "extra set of eyes and mind" to address the challenges at every site, and to adequately check the quality of the work performed at each stage of the work.[134]

9.1.10 Numerous challenges exist in planning and executing a project.

There are a large number of challenges Gas Companies experience in the planning and execution of projects. These are summarized in Table 14.

These challenges are presented as part of this Assessment to highlight that installation of the mains and services can be more complicated than expected. Each of these challenges are often addressed, managed, or both during each project. While resolving each challenge is important, they often affect work flow, which in turn, increases risk (see Section 9.1.5).

[134] While some Gas Companies use multi-layering of oversight positions (i.e., adding construction supervisors or additional quality control personnel rather than using a single inspector at each site), it is unlikely these added layers of supervision can provide the same value to crews as a qualified and engaged inspector who is on site all day, every working day.

Table 14: Challenges During Planning and Execution of Projects

Challenges
MAINS – Planning / Scheduling
• Dig Safe – Locate and mark delays, broken tracer wire • Town/city – Various time constraints imposed by towns/cities and seasons (e.g., work times, winter) • Town/city – Alignment, coordination and cooperation with town/city priorities, including paving projects or other projects • Town/city – Varying permitting requirements • Town/city – Planned events affecting work area, access, or both • Town/city – Chapter 90 reimbursements for capital project (street paving) • Materials – Availability of asphalt during winter months • Funding – Prevailing conditions in capital markets may impact projected costs • Project design – PE approvals, where required • Project design – Delayed projects require re-starts, and often, a change in resources • GSEP – Alignment with cost recovery mechanisms • Workers – availability of trained, qualified and cost-effective labor to perform the work • Customers – Meeting customer expectations including timing, access, reliability, and service level
MAINS – Execution
• Traffic – Timing to minimize public impact, including school buses/school zones • Traffic – Police detail availability • Equipment – Correct equipment, broken equipment • Materials – Cost and availability of raw materials • Work site – Automobile parking that affects work zone • Work site – Public access (bicycles, walkers) in, around, and through work zone • Work site – Maintain access to driveways and business, where possible • Work site – Space restrictions due to road, buildings, overhead wires • Work site – Reconciliation of records • Excavation – Assessment of unidentified buried facilities • Excavation – Rock ditch, boulders, and other buried obstacles • Workers – Restroom facilities • Workers – Safety zones and protection from automobile traffic • Workers – Availability and qualifications to perform certain tasks • Town/city – Various requirements that affect project execution (e.g., no more road plates by a stated date) • Town/city – Hard and soft surface restoration, and approval of same • Procedures – Modifications to work procedures based upon field findings; may require a PE; QA/QC inspection process • Site visits – Manage site visits from company personnel, inspectors, regulators, general public inquiries, and assessments (like this one) • Weather – Rain, heat, cold, snow
SERVICES – Planning and Execution
• Access to residences and businesses, minimize impact • Language and translation • Accessibility to inside meters; limited space, personal belongings • Rock walls and other infrastructure affecting installation of a new service line • Customers – Meeting timing and other expectations • Customers – Hard and soft surface restoration and approval of same

9.1.11 Poor labor relations can adversely impact productivity and safety.

The Panel observed labor relations across many sites. At most of the Gas Companies, union crews and contractor crews demonstrated competence and a focus on safety. At one site, the Panel observed a union crew working hand-in-hand with a contractor crew to install a new service. They communicated well, coordinated timing together, and seamlessly handed off work to one another.[135] This kind of coordination and cooperation, which recognizes that each person on the job is working for the Gas Company – regardless of the type of contractual arrangement – enhances productivity and pipeline safety.

But this was not always true. A different crew, in a separate operating area who were struggling to complete its task, took time to specifically express dissatisfaction with contractor labor in general, even though no contractor was involved at that specific job site.[136] At one large Gas Company, the Panel observed at least three different labor work crews over the course of a single day who seemed indifferent about accomplishing work.[137] At a different work site, a contractor crew working on a complex project for that same Gas Company told the Panel that one union member was unwilling to talk to one of its contract laborers during the project.[138] This type of interaction inhibits necessary communication on job sites and can adversely impact productivity and safety.

9.2 Learning culture was not evident in the field visits.

A learning culture was not evident in the field visits. This was true across all levels of organizations encountered by the Panel. A learning culture is present when individuals and the organization actively seek out learning opportunities, critically evaluate current practices, and develop a deep understanding of the causes of failure.[139]

The first barrier to identifying learning opportunities is overconfidence. The Panel observed a misplaced but often expressed belief that matters were going well at job sites across the Gas Companies. When the Panel asked questions and expressed concerns about specific aspects of the work being performed, the response often indicated *that is the way it is always done,*[140] there was no need to look for similar errors,[141] or, alternatively, that it was not that person's responsibility.[142] Further discussion made it clear there was limited critical self-evaluation of how work was being performed and learning opportunities were being missed.

[135] See Appendix B.1.3, Berkshire.
[136] See Appendix B.1.3, Berkshire.
[137] See Appendix B.8.3, National Grid.
[138] See Appendix B.8.3, National Grid.
[139] A learning culture is a critical aspect of a positive safety culture. See the *White Paper* in Appendix A.
[140] Appendix B.10.3, Wakefield, Appendix B.11.3 Westfield, Appendix B.1.3, Berkshire, Appendix B.2.3, Blackstone Appendix B.3.3, Columbia Gas, Appendix B.4.3, Eversource; Appendix B.8.3, National Grid; Appendix B.9.3, Unitil.
[141] See Appendix B.10.3, Wakefield, Appendix B.11.3, Westfield.
[142] See Appendix B.3.3, Columbia Gas; Appendix B.11.3, Westfield.

The Panel experienced similar reactions from some management teams. When the Panel talked with management at Gas Companies at which the Panel had identified immediate safety concerns, management from two of the four Companies reacted defensively.[143] At three of the four Gas Companies, the corrective actions proposed to the Panel were inadequate.[144] Companies with a strong learning culture would have been interested in engaging the Panel and gathering as much information as possible to understand how they failed, and to help them find ways to improve.[145]

Similarly, two other companies failed to fully embrace the opportunity to learn from line strikes:

1. The first line strike occurred immediately before the Panel arrived onsite. There, the company conducted an on-site off-the-cuff analysis of the causes of a line strike, revoked the operator qualifications of the excavator, and missed an opportunity to identify the numerous other learnings from the incident.[146]
2. At a different Gas Company, the line strike occurred a few days before the Panel arrived. When the crew was asked about the incident, the only thing they had learned from it was that the crew member who had struck the line would no longer be working for that particular company.[147]

In another example observed at main line replacement tie-in, the Panel observed a crew attempting to manage a misalignment of pipe ends to be joined.[148] This misalignment was substantial. It was highly likely that, once fused, the joint would be subjected to significant, and likely unacceptable, torqueing stress. Yet, when the Panel raised the issue to the Gas Company, management was quick to offer assurances that the joint was fit for service as demonstrated through an over-simplified calculation. Furthermore, it was not apparent from these assurances that any root cause analysis (RCA) had occurred or would occur after the Panel's questions were addressed.[149]

[143] Contrary to being a learning organization open to feedback, senior management at both Westfield and Wakefield signaled that the Panel's observations were unwelcome. See Appendix B.11.3, Westfield and Appendix B.10.3, Wakefield. Some of the questions also suggested a basic lack of knowledge of certain operational and construction execution issues.

[144] See Appendix B.11.3, Westfield, Appendix B.10.3, Wakefield, and Appendix B.3.3, Columbia Gas. As one example, after the Panel observed the contractor on site exhibit a number of concerning safety behaviors, one Gas Company's corrective action was to name the contractor as the responsible party on the job site. See Appendix B.11.3, Westfield.

[145] As an example of a lack of a learning culture, the Panel's inquiries to the operations' team lead regarding concerns about operator qualifications for abandonment work were met with a shrug and the claim it had always been done that way. See Appendix B.9.3, Unitil.

[146] See Appendix B.4.3, Eversource.

[147] See Appendix B.3.3, Columbia Gas. The quick action to ban the crew from the worksite (and to revoke the operator's qualification and terminate employment in the Eversource line strike situation) suggests a simplistic view of incident causation that is based on a personal perspective view of human error (i.e., errors occur due to a lack of motivation or ability). This is inconsistent with current human error research. Instead, a learning culture would view the error resulting in a line strike as a symptom of how safety was being managed on the site, and perhaps more broadly, in the entire company – and would seek to identify those weaknesses. This review would take time and should be transparent to all involved. It is possible that this review might identify crew competence and behavior as a factor, but also this would raise the broader issue of contractor selection or oversight, not simply banning a crew. In addition, taking a punitive approach that appears to be based on the outcome (striking the line) and not the specific action will be viewed as unjust by crews and create tension and distrust. The Panel observed evidence of this tension and distrust at a number of sites.

[148] See Appendix B.3.3, Columbia Gas.

[149] The Panel issued IR#9 to Columbia Gas on November 7, 2019. The company responded in writing on November 12, 2019 that, based on preliminary engineering calculations and input from internal subject matter experts (i.e., engineering, construction and gas standards), the Gas Company did not believe there was a need for immediate action. After additional follow up by the Panel and the DPU, the Company assured the Panel and DPU on November 13, 2019 that they had *confirmed that there is not a safety issue* at the location.

Two companies stood out as welcoming input and embracing the opportunity to learn.[150] Both Holyoke and Eversource undertook efforts to solicit and understand the Panel's feedback.[151] Eversource immediately stopped work at one site based on the Panel's observations, and the Panel later received a call from Eversource's leadership expressing a desire to learn more about the Panel's feedback. Eversource further assured the Panel it would follow up by providing corrective action to the DPU within 30 days.[152]

9.3 Effective process hazard analysis seldom occurred.

Connected to the lack of effective job briefs and rarely exhibited learning culture, the Panel observed crews spent little time to assess the situation for hazards or to consider what could go wrong in the tasks ahead.[153] If implemented correctly, a process safety hazard identification process prompts the crew member to observe and analyze their surroundings. This can be done by asking: *what is the worst thing that could happen? What are the barriers of protection? If it happens, what actions will it take to mitigate the situation? What are the barriers of protection and how do I engage them?* When hazards remain unrecognized or the associated safety risk remains unperceived by the worker, the likelihood of human error increases.

The development of a robust process safety hazard identification process would require all personnel at all job sites to stop before beginning work to assess the situation for hazards. This focus on recognizing hazards and perceiving safety risks are fundamental steps to effective safety management. It helps focus the mind of the person(s) who are about to perform the task to the specifics of the task at hand. It moves the mind away from potential distractions to the potential hazards and barriers to those hazards.

9.4 Gas Company size offers different challenges.

As discussed in Section 8.1.5, each Gas Company faces different risks based on its history and assets. In addition, the Panel found that the size of the company also corresponded to the risks it faces. The Gas Companies fall into three size categories:

1. Large Companies

   This includes companies that have a large presence in the Commonwealth and are part of a larger corporate organization. Large Gas Companies in Massachusetts are National Grid, Eversource, and Columbia Gas.

[150] The Panel had discussions about its observations with several other companies, which largely were met with a modicum of interest. The Panel recognizes some Gas Companies may have felt constrained by the Assessment process and consequently elected not to seek the Panel's input after the Final Report.

[151] See Appendix B.4.3, Eversource and Appendix B.5.3, Holyoke.

[152] During the Snapshot Review Process, Eversource indicated the DPU Division of Pipeline Safety advised them to fill out the usual paperwork used to report a line strike. This represents a missed opportunity for the DPU to work with Eversource to improve pipeline safety and likely was the product of interaction occurring during the timeframe the DPU was transitioning to new Director of Pipeline Safety at the DPU.

[153] The Panel observed three exceptions where a competent contractor crew chief did an excellent job of identifying and explaining the hazards. For these exceptions, see Appendix B.1.6, Berkshire, Appendix B.4.6, Eversource, and Appendix 6.c, National Grid. See also, the discussion in Section 9.1.4.

2. Mid-sized Companies

   This includes companies that have a small or medium-sized presence in the Commonwealth and are part of a larger corporate structure outside of the Commonwealth. These Gas Companies are Unitil,[154] Liberty,[155] and Berkshire.[156] These tend to be referred to in Massachusetts as *mid-size* companies despite benefiting, like the large companies, from being part of a larger organization.

3. Companies with smaller gas systems

   These companies include Blackstone (which was privately owned before its pending acquisition by Liberty) and the four gas companies whose rates are set by the Municipal entities that own them: Holyoke, Middleborough, Wakefield, and Westfield.

The benefits of a large company, whether operating large systems inside Massachusetts or not, include immediate resources, deeper technical expertise, and more core business support.[157] This enables these companies to have more formal processes and more resources to call upon, providing more rigor around processes and less latitude than in smaller companies. This size is a benefit given the complexity of the systems operated by the large companies.

It also provides management challenges. The larger companies can have silos of responsibility that can make clear and consistent communications challenging, with or without appropriate management. In these companies, completion of a simple job involves several handoffs to and from different personnel within the organization. This creates many opportunities for error and miscommunication. Additionally, to the extent that silos limit the perspective of personnel, silos may also:

- Create a lack of accountability;
- Inhibit the ability or personnel to see the impacts of their work; and
- Reduce critical thinking and basic on-the-job curiosity.

Further, budget constraints may be impacting decision making at certain companies.[158]

By contrast, the smaller Gas Companies usually excelled in clear communications and team cohesiveness. But smaller companies, like Middleborough and Blackstone, lacked deep technical expertise, generally have little core business support,[159] and generally operated with a great deal of

[154] See Appendix B.9.1. Unitil's operating utilities serve nearly 105,000 electric customers and natural gas customers in Maine, Massachusetts, and New Hampshire.

[155] See Appendix B.6.1. Liberty provides natural gas to over 290,000 customers in Georgia, Illinois, Iowa, Massachusetts, Missouri, and New Hampshire.

[156] See Appendix B.1.1. Berkshire is part of Avangrid, which is a sustainable energy company with $32 billion in assets and operations in 24 US states. It owns eight electric and natural gas utilities. It has an $8.3 billion rate base serving 3.1 million customers. Avangrid is owned by Iberdrola.

[157] This means the core gas business is supported by a variety of services, which include in-house engineering, contract and supply management, and a variety of departments including those dedicated to regulatory compliance, facility management, human resources, and legal services. They are also likely to have groups dedicated to training and each of the PHMSA-mandated programs (including DIMP, Damage Prevention, Operator Qualifications, and Public Awareness).

[158] The Panel mainly heard concerns about budgets impacting availability of resources to enhance pipeline safety at Unitil and Berkshire. See Appendix B.9.3, Unitil and Appendix B.1.3, Berkshire. The Panel did not explore the basis for these concerns.

[159] Some of the smaller companies hired third-party expertise to help establish manuals to meet compliance requirements. This is a helpful approach to accomplish those goals; however, third-parties are not actively involved in managing the systems on a day-to-day basis.

overconfidence. To a large extent, the small size and simpler gas systems of these smaller Gas Companies will help limit opportunities for devastating mistakes.

While the challenges and expertise vary across the Gas Companies, each is generally aligned with the needs of their gas systems. Moreover, it would be unreasonable to assume that the smaller Gas Companies would have the expertise to manage the magnitude and complexity of work undertaken by the larger Gas Companies.

9.5 Improved tracking of safety critical events, like over-pressurization, would enhance learning.

Tracking of safety critical events helps enhance learning. One example is tracking and understanding over-pressurization events on gas systems. The Panel asked the Gas Companies to provide data about over-pressure events on their gas systems over the last five years. The large companies, that is those with gas control centers, found collecting and providing the data difficult – especially with any level of detail or analysis of cause.[160] By contrast, the smaller companies, with less complex systems and no gas control centers, found responding easy because their systems had not experienced an over-pressure event in the last five years.

The difficulty in responding to the request suggests that large Gas Companies may not be appropriately tracking, managing, and learning from safety critical events – such as an over-pressurization of a low-pressure system.

Moreover, the Panel learned of two over-pressurization events that occurred in 2019 in a low-pressure system operating in another state and operating under the same *O&M Manual* as a Gas Company.[161] In the first, the company did not consider it sufficiently significant to report it to PHMSA.[162] This conclusion is difficult to reconcile given the deleterious impacts of that event. In the first incident, hundreds of customers were out of service for days, electricity was shut-off, and an emergency incident command center was set up to address the issues resulting from over-pressurization.[163] In the second, a house was destroyed and five people were injured and the company filed a PHMSA incident report.[164] The lack of transparency in not reporting the first incident interferes with the ability of other Gas Companies to know about and learn from this and other incidents. Moreover, it prevents federal and other state regulators and the public from being fully informed about significant events.

[160] Since 2013, the three large Gas Companies collectively experienced just under 40 over-pressure events on their low-pressure systems. Those reported by National Grid and Columbia arose from a variety of circumstances and causes. Eversource did not provide the Panel with information about the circumstances or causes of its over-pressure events.

[161] See Appendix B.3.3, Columbia Gas.

[162] See footnotes 74 and 75. An incident becomes reportable to PHMSA if it meets the criteria set forth in 49 CFR §191.3. The third criteria for reporting is an event that is significant in the judgment of the operator, even though it does not meet the first two criteria. Columbia Gas of Ohio *did* report the incident to the Ohio Public Utility Commission.

[163] See public reporting on the gas over-pressurization event on a distribution system in Zanesville, Ohio on a gas distribution system operated by Columbia Gas of Ohio: https://www.zanesvilletimesrecorder.com/story/news/2019/05/09/columbia-gas-shutting-off-service-south-side-zanesville/1156699001/

[164] See public reporting on gas over-pressurization event at a house in North Franklin Township, Pennsylvania on a gas distribution system operated by Columbia Gas of Pennsylvania: https://pittsburgh.cbslocal.com/2019/08/01/columbia-gas-claims-responsibility-north-franklin-township-explosion/

Larger companies typically also experienced a number of over-pressure events on their medium- and higher-pressure systems.[165] While these higher-pressure systems are generally more resilient, the number of over-pressurizations suggest the Gas Companies should review their settings to provide operational control without exceeding maximum allowable operating pressure (MAOP).

9.6 Certain measures may be creating a false sense of comfort.

Gas Companies, State Agencies, and Interested Parties rely on a number of measures to confirm Gas Companies are operating their pipeline systems safely. If implemented appropriately, each may be a building block towards improving safety – but alone may not be a sufficient indicator of a safely-operated system, especially when many measures appear to be in relatively low maturity. These include regulatory compliance, operator qualifications, the use of a PE stamp, and the implementation of a safety management system.

9.6.1 Regulatory Compliance is the foundation for pipeline safety.

The Panel observed several trends indicating that Gas Companies, State Agencies, and Interested Parties share a focus on confirming Gas Companies are meeting their compliance obligations. Underpinning this focus appears to be a belief that if Gas Companies meet their compliance obligations then pipelines will be operated safely. Compliance with the Federal and state regulatory requirements related to gas pipeline safety is insufficient to make operations of gas pipelines safe because:

1. Regulations provide the minimum safety requirements. As such, while compliance is the basic foundation for safety, merely being compliant is insufficient to achieve the level of safety the public expects and deserves. Gas Companies must go beyond compliance to focus on safety and embrace continuous improvement in all they do;
2. An intense focus on meeting compliance requirements can mask or distract from other important safety issues; and
3. When compliance is attained, further effort on that issue stops. Safety, on the other hand, is never *attained*. That is, safety is a journey rather than a destination. Thus, efforts to improve safety should be continuous.

9.6.2 Certifications, such as Operator Qualifications or requiring a professional engineer stamp, are the beginnings of becoming qualified for the task.

Certifications of a certain level of knowledge are a good first step in identifying individuals qualified to perform the tasks involved in designing, operating, and maintaining gas systems. They are, however, merely a first step – a foundational minimum requirement. Experience and additional training are also required. The Panel observed overconfidence on the ability of the Operator Qualification testing process to verify an individual is qualified to perform gas work. While the Operator Qualification process as it exists today meets the currently intended purpose, there is an opportunity to evolve it from a certification process to one that assesses an individual's qualification and competency to both understand the hazards and perform the work safely. Similarly, as

[165] Collectively, the large Gas Companies (National Grid, Eversource, and Columbia Gas) reported over 85 over-pressurization events between 2013 through mid-2019 on their medium- and high-pressure systems, with the vast majority being slight variances above MAOP.

discussed in Section 9.1.7, the fact that an individual has passed the rigorous test to become a PE does not alone qualify that individual to evaluate and design gas systems or processes without additional training and experience.

9.6.3 Appropriate implementation of API RP 1173 is a first step in a long journey.

A safety management system, such as the one embodied in API RP 1173, is an excellent tool to help a company better embrace the mindset of continuous improvement. Adopting and operationalizing a safety management system within a company is a long journey of continued improvement over time.

The Panel expects that the adoption of API RP 1173 by the Gas Companies[166] will ultimately have long-term effectiveness. It becomes the method to help break down silos and leads to understanding the intra-dependency of work that exists. For instance, using safety process hazard identification,[167] improving safety culture, and embracing learning are all parts of a well-functioning safety management system.

In the shorter term, the Panel observes implementation may be more of a distraction for many of the companies that have more fundamental opportunities to improve pipeline safety in the near future.[168] Because every company has limited resources to implement new initiatives, consideration should be given to how best to focus efforts on useful, short-term improvements, like those mentioned above which offer more immediate benefits rather than waiting to develop and implement a complete safety management system.

9.7 Integrity management plans lack sufficient focus on risk.

Integrity management plans meet compliance requirements but need more focus on risk assessments. Sound risk management practices require full consideration of all types of threats that could adversely impact pipeline safety. Implementation of a DIMP should be accompanied by a full consideration of all threats, not purely focused more narrowly on leak prone pipe. Thoughtful analysis and consideration must be given to what is currently unknown and what might constitute a future threat. Other observations include:

- Risk management efforts, especially as set forth in a Gas Company DIMP, are focused primarily on leak prone pipe rather than all potential threats; and
- Consideration for the identification of low probability, high impact events is minimal.

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[166] In the aftermath of the tragedy in the Merrimack Valley region, EEA requested that the Gas Companies consider adopting API RP 1173. The Gas Companies agreed and the Northeast Gas Association, a trade organization that represents the Gas Companies and other companies that operate natural gas pipeline infrastructure in the Northeast region, agreed to hire a third-party contractor to help the Gas Companies adopt and "operationalize" API RP 1173. As the Panel conducted its field observations, the third-party contractor was meeting with the Gas Companies to begin assessing their readiness and next steps.

[167] The Panel's observations about the benefits of embracing each of these are discussed in Section 9.3, Section 7, and Section 9.2.

[168] On several occasions, individuals invoked the implementation of a safety management system in a manner that demonstrated they misunderstood the basics of such a system and failed to realize that improving safety culture is a journey that takes time.

9.8 Company asset records remain a challenge.

Gas Companies have the opportunity to improve records related to their assets. These opportunities include improving quality, accessibility to records, and better establishing and documenting methods of updating records based on findings in the field. Each Gas Company needs to know its systems well enough to identify and mitigate all the threats to pipeline integrity and to make good operational decisions. They also would benefit from having processes to improve recordkeeping each time a pipe is uncovered.

In field visits, the Panel observed crew chiefs taking measurements of newly installed assets and recording its detailed information by hand in a book or on paper.[169] From there, the information was transcribed into a more formal drawing, or delegated to another person to transcribe into a more official record. While crew chiefs and inspectors took this part of their job quite seriously and produced excellent drawings, the process provides many opportunities for the inadvertent introduction of error. For instance, each re-drawing, handoffs and re-typing to get the information into a system of record creates opportunities for error. Also, documents can be misplaced between the field and the office where the transcribing takes place.

Several Gas Companies use electronic means to display asset information, record asset information, or both in the field.[170] These efforts are to be applauded. One benefit of electronic tools is the small amount of the time it takes to record newly installed assets in formal records. Nonetheless, there remains a significant amount of error in records (e.g., on paper and electronically). This fact must temper reliance on records and urge crews to undertake secondary steps to further validate the location of assets.

In addition to concerns about records management and lack of confidence in legacy data, the Panel observed issues with accuracy even in more recent pipeline records (both construction and test records). At one Gas Company,[171] a new main was being installed that needed to cross a recently installed line. The backhoe operator reviewed the street marks and the drawings and then attempted to find the line based on that information. It took a number of efforts to find the recently installed line. While the records turned out to be accurate, the drawings by an outside engineering firm were not. In another field visit, the crew was installing a new service line to a home. The existing line (installed in 2001) was incorrect on the map. The crew lead identified this discrepancy early in the job and developed a different plan to install the new line.

9.9 Emergency response programs have room for improvement.

While Eversource and National Grid have outstanding emergency response programs and practices, the Panel found all Gas Companies have opportunities to improve preparedness in responding to a Level 3 or greater gas emergency. These opportunities relate to:

- The emergency response (ER) plans, including improvement of communication protocols and technology choices;
- Engaging in more mock emergency drills, including both tabletop and field; and
- Improving outage management systems.

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169 This has been a viable tool and can remain one with sufficient checks in the process.
170 See Appendix B.4.3, Eversource (use of iPads to record real time data on job sites); Appendix B.1.3, Berkshire (use of tablets).
171 See Appendix B.10.3, Wakefield.

The Panel also notes the benefits and pitfalls that may arise for a Gas Company that has experience in responding with its related electric company to electric emergencies. (See Section 9.9.4).

9.9.1 Emergency response plans are not being critically reviewed by all Gas Companies.

Except for those used by Eversource and National Grid, the ER plans, while generally compliant with regulatory requirements, provided insufficient detail and guidance to be fully useful during an emergency. ER plans would benefit from:

1. A thorough ER plan review to ensure focus is on an effective, coordinated response with outside agencies when warranted versus a focus on compliance with regulations;
2. Adopting more consistently the Incident Command Structure (ICS) and the adoption of common terminology, functions/position titles, accountabilities, and incident typing;
3. Naming specific individuals, capabilities and functions, and providing contact information for those individuals;
4. Clarifying communications and coordination of internal stakeholders;
5. Recognizing outside responders and the necessary coordination that will be required with outside agencies, such as local police or fire departments;
6. Reviewing outside resources that may be useful in an incident, particularly for municipal Gas Companies that may be able to draw on city/township resources; and
7. Adding and meeting new training requirements of emergency response and ICS training for all named participants.

9.9.2 Gas Companies would benefit from more mock emergency drills.

Gas Companies would benefit from actively participating in more mock emergency desktop and field exercises, and drills. Following the release of the *Phase 1 Report* in May 2019, majority of Gas Companies have engaged in an emergency drill. These are set forth in Table 15.

Table 15: Gas Company Mock Emergency Drills since Phase 1 Report

Date	Company	Description
8/6/19	National Grid	Tabletop exercise with National Grid and local authorities
8/28/19	Columbia Gas	Tabletop exercise
10/25/19	Eversource	Planning for upcoming Eversource's Live Action Drill
9/24/19	Westfield	Tabletop exercise with HG&E and local officials
9/25/19	Holyoke	Tabletop exercise with HG&E and local officials
9/26/19	Wakefield	Tabletop exercise with WMGLD and local officials
9/27/19	Middleborough	Tabletop exercise with MGED and local officials
10/2/19	Columbia Gas	Live Action Emergency Drill
10/25/19	Eversource	Live Action Emergency Preparedness Drill
11/19/19	Blackstone Gas	Emergency Preparedness Drill with BGC and local authorities
11/25/19	CMA	After Action Review of Emergency Exercise in October

The remainder of Gas Companies have not practiced desktop or field drills either before or after issuance of the *Phase 1 Report*.[172]

To be ready to respond to an emergency, organizations must practice and drill until the response becomes second nature. This should include all departments and individuals who have accountabilities in the emergency response plan. There is much work to be done in the journey of continuous improvement on this front.

In addition, communication protocols and use of technology can be improved. Almost all of the Gas Companies:

- Can improve their emergency communication practices and protocols with customers, elected officials, and the media; and
- Are overly-dependent on cell phones to manage critical emergency response communications, with few backup plans should cell coverage become unavailable.

9.9.3 Creating outage management systems to manage data currently residing in various databases.

When a Gas Company responds to an emergency, some of the first steps are to:

- Assess the extent of the gas outage; and
- Confirm that gas has been turned off at each customer site (e.g., homes and businesses).

Gas Companies could develop an outage management system that quickly integrates customer and asset data contained in various databases using technology (e.g., software). Undertaking this effort while not operating in emergency response mode could help accelerate the recovery time and assist in responding to a Level 3 (or greater) gas emergency.

9.9.4 Gas Companies benefit from being part of an organization that also operates electric companies.

The Panel notes that those Gas Companies that are part of an organization that also operates electric companies benefit from that association.[173] Most gas employees would have had more exposure to practicing emergency response drills by virtue of the number of storms that cause electric outages. There are, however, some significant factual differences between an electric power outage emergency and a gas emergency. These include:

1. Electric outages usually occur after a few days' notice of a storm warning, which allows time to prepare and stage resources for a faster response time. Gas emergencies generally occur with no advanced warning or planning opportunities;

[172] The *Phase 1 Report* recommended, among other things, that Gas Companies take steps to improve emergency response plans including conducting a tabletop and field emergency response preparedness drill. It appears that Liberty, Unitil and Berkshire have not undertaken an emergency mock drill – tabletop or field exercise – since the release of the Phase 1 Report. See Liberty, Unitil and Berkshire in Appendix B.

[173] This may not always be true. In some instances, gas companies organized with electric companies receive fewer revenues and attract less management attention than their electric counterparts. For example, Westfield's senior management seemed less familiar with gas pipeline safety matters. Too, excavations occurred near utility poles without coordination between the two business units.

2. Electric infrastructure enables electric grid operators to determine the parameters of the outage based on meters that are no longer active. By contrast, gas infrastructure has no similar feature to determine who is with or without gas. Instead, a Gas Company representative must visit each customer (e.g., home and business) to determine who has gas service and who does not. After the scope of the outage is known, a plan can be created to restore service;
3. When an electric outage occurs, it fails in a “safe mode”. That is, when the electricity turns off, the public is not at risk from being electrocuted in an outage situation (with the exception of live downed electric wires). In a gas emergency, the public may be at risk because gas may be actively leaking into homes and businesses. This creates an urgency for gas-leak detection, and the need to focus efforts and resources on first evacuating people and on making the area safe for others to enter; and
4. Restoring electrical power usually does not require entry into customers’ homes. Gas outages require entry into customers’ homes and businesses when meters are located inside. Further, regardless of meter location, a second visit is needed to turn the gas back on, perform a safety check, and, in many cases, perform relights.

Thus, even Gas Companies that manage electric power outages may not have the required experience and practice to respond appropriately to gas emergencies.

10 Observations about State Agencies and Interested Parties

10.1 Observations about the DPU

While each Gas Company is accountable for safely operating gas distribution systems to reliably deliver natural gas to customers, the DPU has an important inspection, enforcement, and ratemaking role in supporting and encouraging pipeline safety. Sections 10.1.1 to 10.1.10 present the Panel's observations about the DPU. As presented here, the DPU has made notable improvements since the September 2018 incident in Merrimack Valley and in response to the *Phase I Report*. As explained below, the DPU still has opportunities to continue its progress and improvements to pipeline safety.

10.1.1 The DPU meets PHMSA requirements.

As permitted under Federal law[174], PHMSA has delegated its oversight and enforcement obligations related to intrastate pipeline safety to the DPU. Each year PHMSA undertakes an evaluation of the DPU's Division of Pipeline Safety Program. Between 2009 and 2018, PHMSA found that the DPU met its requirements.[175] PHMSA also found that the DPU's enforcement of excavation damage prevention law to be adequate as of December 31, 2018.[176]

10.1.2 The DPU's Division of Pipeline Safety handles a wide range of topics.

The DPU's Division of Pipeline Safety's handles a wide range of topics related to pipeline safety. They perform inspections and audit on a broad variety of topics (and sub-topics) including:

- Construction (with sub-topics such as district regulator stations, plastic pipelines, and welding);
- Damage Prevention (with sub-topics including locate and mark pipelines and the inspection of third-party damage);
- Distribution Integrity Management Programs (with sub-topics of evaluate and rank risk, knowledge of the system, and records);
- Integrity Management (with sub-topics in areas like baseline assessment, external corrosion direct assessment, and in-line inspection);

[174] PHMSA certifies State Agencies to act on PHMSA's behalf under 49 U.S. Code § 60105.

[175] PHMSA evaluates the state programs using a number of points available each year and the number of points scored by a given state to arrive at a state rating. Find annual reports at:
https://www.phmsa.dot.gov/working-phmsa/state-programs/evaluation.
Between 2009 and 2017 (the last year for which data is currently available), the Massachusetts DPU State Rating averaged 93.2, with a high of 97.4 in 2017 and a low of 87.4 in 2011.

[176] In a letter to the DPU dated June 10, 2019, PHMSA found that as of December 21, 2018, DPU's enforcement of excavation damage prevention law was adequate. In a similar letter, dated December 28, 2016, PHMSA raised a concern that the DPU regulations did not contain a requirement for excavators to call 9-1-1 or other emergency telephone number if damage to underground facilities results in an escape of gas. As discussed in Section 10.1.3, the DPU has already addressed that concern with a recent update in regulations.

- Maintenance (with sub-topics such as leak repair and leak surveys); and
- Standard Comprehensive (with sub-topics such as abandonment, purging, cast iron, operations and management, and tapping).

They also perform inspections at Gas Companies and audit Gas Companies' programs related to:

- Control room management;
- Drugs and alcohol;
- LNG facilities;
- Meter replacement programs;
- Operator qualifications; and
- Public awareness.

This broad mandate combined with their funding level makes it difficult for the limited staff to cover all areas effectively. As discussed in sections 10.1.4 and 10.1.5, while increased funding in 2019 has helped to address this challenge, providing appropriate resources should remain a focus.

10.1.3 The DPU's organizational structure would benefit from more emphasis on pipeline safety.

The DPU would benefit from an organizational structure that puts more emphasis on pipeline safety. Currently, the Division of Gas Pipeline Safety is just one of many divisions within the DPU.[177] In addition, the Division of Pipeline Safety and the general topic of pipeline safety have not traditionally been well-integrated or coordinated across actions performed and decisions made by the other divisions. For example:

- It appears DPU staff working on rate cases rotate between different types of rate cases and as such, may not have developed sufficient expertise to properly evaluate investor-owned Gas Companies' claims regarding the need or method to enhance pipeline safety;
- Notable resources appear to be focused on the pricing of gas supply but not focused on safety concerns arising from potential gas supply constraints; and
- While the DPU has not decided a gas rate case it received since the 2018 Merrimack Valley incident, historically, rate case decisions appear to be more focused on keeping rates low than on ensuring operators are taking necessary and appropriate actions to enhance pipeline safety.[178]

[177] See Footnote 15.

[178] Roughly two weeks after the 2018 Merrimack Valley incident, the DPU issued a rate case order that significantly reduced National Grid's rate of return and revenue because of the DPU's concerns about that company's safety practices. D.P.U. 17-170, at 310-13. While the DPU likely intended to send a message about the importance embracing pipeline safety, the punitive nature of this action may not result in the desired outcome. As discussed in Section 10.2.1, many of the efforts to improve pipeline safety require Gas Companies to incur additional costs. If the rate of return on which the Gas Companies can earn on the capital invested is lowered, the practical impact may be a reduction in funds spent on improving pipeline safety rather than the desired increase in focus on pipeline safety.

10.1.4 The DPU's new personnel hires are poised to improve regulatory oversight.

In 2019, the DPU hired additional inspectors and a new Director of Pipeline Safety (Director). The new Director began work in September 2019. Since the 2018 Merrimack Valley incident, the DPU's Pipeline Safety Division has gone from the agency's fifth largest division to become its largest division. The Panel observed the impact of this new leadership and personnel in the role the DPU undertook in response to concerns that came to light in early September 2019 about Columbia Gas' abandonments of services during the restoration of service following the September 2018 Merrimack Valley incident. The Director and staff from the Division of Pipeline Safety undertook immediate action and provided clear direction to Columbia in terms of the DPU's expectations, including relaying the consequences of any violations.

10.1.5 The DPU still faces challenges in recruiting and training staff in a timely manner.

While the DPU successfully hired a new Director and additional staff, their inability to offer competitive compensation to the DPU inspectors makes it difficult for the DPU, and specifically the Division of Pipeline Safety, to recruit and retain sufficient personnel with comprehensive pipeline safety knowledge. Furthermore, this puts an additional burden on existing technical staff. Adding additional qualified personnel could help shift the focus of inspection and enforcement efforts by the DPU from compliance to pipeline safety. Also, additional qualified staff should enable additional DPU inspectors to review Gas Companies' work practices in the field.

10.1.6 DPU inspectors with broader focus during inspections may be more effective.

DPU inspections may be more effective in promoting pipeline safety if focused more broadly on what is observed in the field. In the past five years or so, the division organized audits to assign a specific auditor to specific companies, and to focus on one PHMSA-mandated program[179] at a time. The goal was to ensure the Division accomplished the PHMSA-mandated program reviews within the mandated time. For instance, an inspector would visit a gas company to review its public awareness program, but would not necessarily be concerned with the company's Dig Safe Program.

Based on a review of DPU Division of Pipeline Safety records made available to the Panel, DPU PHMSA mandated program inspections accounted for over 50% of the inspections conducted by the Division from 2016-2018.[180] The Panel observes that DPU resources may be more effective in promoting pipeline safety if the DPU inspectors were empowered to use the opportunity of the audit to observe the company activities from a broader viewpoint of safe operations.

10.1.7 DPU records, data, and database access could be improved.

It was difficult for the DPU to provide a timely response to the Panel's requests for inspection records and information on the effectiveness of past inspections. While the DPU's Division of Pipeline Safety keeps a database of activities, it apparently has limited search capabilities.

[179] Some PHMSA-mandated programs include drug and alcohol inspections, public awareness program inspections, and operator qualification inspections.

[180] As discussed in Section 10.1.7, DPU data provided to the Panel indicates that 2,566 DPU inspections were conducted within three years (2016-2018). Of these inspections, the Panel's review suggests 800 records are multiple records of different DPU inspectors documenting the same inspection. Program assessment inspections make up 900 of the 1,766 non-duplicative inspections or 50.9%.

Of the records that were produced, the Panel found more than 800 instances of multiple records from the same inspection filed by a different inspector. It is not clear if this is a data entry error or if multiple DPU inspectors attended the same inspection and filed separate reports. There were also errors in which enforcement actions made reference to inspections for which there were no inspection records. Again, it is unclear whether this was an issue with the availability of the underlying inspection information or some other error.

The DPU Division of Pipeline Safety has an opportunity to improve recordkeeping, data management, and database search capabilities.[181]

10.1.8 Frequency and type of DPU inspections varied by Gas Company.

The frequency and types of DPU inspections have varied in the past by Gas Company. For instance, in the three years for which the Panel requested information (2016-2018), National Grid was the only company that had its DIMP audited. Furthermore, it was audited 16 times within this period.

No other Gas Companies' DIMP plans were audited in 2016, 2017, or 2018.

Every Gas Company was the subject of an inspection or audit in the area of construction during between 2016-2018. Every Gas Company also had an inspection under the topic of "Standard Comprehensive."[182]

Over three years (2016-2018), DPU records indicate it conducted over 1,400 separate inspections of the Gas Companies. It also issued 9 warning letters and initiated 13 Notices of Probable Violation (NOPV). National Grid received 5 out of the 9 warning letters and 8 out of 13 of the NOPVs.[183] Of the 13 NOPV's, the Panel learned that 9 of them remained open as of mid-2019. [184]

10.1.9 Repeat offenders may be deterred by DPU's increased penalties for Dig Safe violations.

Managing the threats arising from excavation around gas infrastructure requires the focus of the Gas Companies, the DPU, and Interested Parties.[185] Since issuance of the *Phase 1 Report*, in which the Panel recommended an increase of penalties for repeat offenders of Dig Safe regulations, the DPU has undertaken efforts to improve the Dig Safe regulations.[186] In the Final Regulations, issued

[181] The new Director of Pipeline Safety has reached out to pipeline safety divisions in other states to determine what software they use and their best practices for data management. This is a positive step and it would be beneficial for the new director to continue to make prompt improvements in this area a priority.

[182] The sub-topics of these inspections were not clear from the records.

[183] None of the warning letters issued to National Grid refer to, or appear to have arisen from, the inspections. Only three of the NOPVs appear to reference the inspections.

[184] Timeliness for completion of an enforcement action is also an issue for appeals following the imposition of a penalty. In one matter involving a fine issued to Wakefield, the matter has been on-going for multiple years and remains pending at the DPU's Division of Pipeline Safety. See Appendix B.10.3, Wakefield.

[185] Opportunities for Gas Companies to improve by clarifying expectations about excavation practices are discussed in Section 9.1.3. Opportunities for the Massachusetts Legislature are discussed in Section 10.4.

[186] On July 18, 2019, the DPU issued an Order adopting Emergency Regulations in DPU 19-43. It subsequently received written comments and held hearings before issuing the Final Order on October 4, 2019. DPU 19-43-A (Order Adopting Final Regulations).

October 4, 2019, the DPU substantially increased the potential enforcement penalty amounts.[187] With this additional authority, the DPU will be in a better position to use increased penalties to deter repeat offenders.[188]

10.1.10 The DPU's efforts at improving pipeline safety can become more effective.

In addition to the items discussed in sections 10.1.3 to 10.1.7, the DPU's Division of Pipeline Safety can enhance its efforts at improving pipeline safety by undertaking reforms. These include:

- Set and meet appropriate response timelines for enforcement actions;
- Increase transparency as a guiding principle for DPU Pipeline Safety Division actions and the status of those actions;
- Embrace a pipeline safety culture pillar of encouraging and rewarding learning organizations;
- Provide Gas Companies sufficient time after an inspection or other enforcement action to identify, develop, train, and then execute corrective actions (which, at the discretion of the DPU, may be supervised by the DPU or a third-party) before taking additional action;
- Use penalty authority clearly and with purpose when Gas Companies act deliberately, recklessly or with disregard in the face of learning opportunities; and
- Publish an on-line list of excavators that repeatedly fail to call 8-1-1 and damage underground facilities. Include the amount of each penalty in the publication as a deterrent.

10.1.11 The DPU's recent efforts have enhanced GSEP.

The DPU's holdings in recent GSEP orders will help enhance the GSEP process in two ways: increasing the revenue cap and expanding the category of eligible pipe. Prior to 2019, a Gas Company's rate recovery for GSEP work generally was capped at 1.5% of the gas company's revenues for the prior year. In these recent orders,[189] the DPU determined that it had authority to approve a cap greater than 1.5%. In recognizing the intent of the Legislature to accelerate the repair or replacement of aging or leaking natural gas infrastructure, the DPU found a 3.0-percent GSEP cap likely would be beneficial.[190] Accordingly, the DPU held in April 2019, that beginning with the 2019 GSEP an LDC may see recovery up to the 3% cap. The Panel notes additional waivers may still be appropriate to the extent Gas Companies demonstrate their mains and services' replacements reduce risk. These orders also expand the categories of eligible infrastructure under GSEP to include

[187] For violations relating to natural gas pipeline facilities, the Order gives the DPU discretion to impose fines higher than $1,000 for first time offenses or $10,000 for subsequent offenses where appropriate. It also retains the DPU's discretion to offer training to first time offenders in certain situations. The new regulations also clarify that damage is not required to find a violation.

[188] The modifications address the issue that under the earlier penalty structure, repeat offenders could lose more money by stopping work while they allowed a proper locate and mark to occur than by incurring the penalty.

[189] See, e.g., DPU 18-GSEP-04, Liberty Utilities (declining to grant Liberty its specific waiver to the GSEP cap for 2019, but noting that any revenue requirement approved in excess of the 3% cap may be deferred for recovery through GSEP the following year or under traditional ratemaking in the next base distribution rate case).

[190] The DPU recognized the need to balance the benefits of an accelerated pace with potential bill impacts on ratepayers and the risk of rate shock caused by cost deferrals. It also found that a majority of LDCs indicated a 3.0% cap was high enough to avoid or would mitigate future deferrals while facilitating timely achievement of the Gas Companies' GSEP goals.

Aldyl-A pipe installed prior to 1985.[191] These improvements appropriately focus DPU's analysis of the GSEP filing on the reduction of risk.

10.2 Observations about the Role of the AG's Ratepayer Advocate

The AG Office[192] participates as a ratepayer advocate on behalf of consumers in the Commonwealth in matters before the DPU.[193] The Panel's observations:

- Cover the benefit of adding a pipeline safety expert to the AG's team (Section 10.2.1);
- The opportunity to with keep costs lower by also focusing on costs outside the control of the Gas Companies (Section 10.2.2); and
- The impact of the perception of outsized influence because the role is set within the AG's office (Section 10.2.3).

10.2.1 The AG's office would benefit from including a pipeline safety expert on its team.

The AG Office views its role in matters before the DPU as advocating for safe and reliable service at the lowest cost possible.[194] Meeting these goals, however, requires balancing the innate tension between costs and safety.[195] Currently, AG offices have access to economists to assist with financial matters.[196] While the AG has supported some Gas Company proposals for improvements in the past,[197] it would also benefit from adding a pipeline safety expert to its staff.[198] Such a technical expert could assist the AG in the evaluation of Gas Companies' requests for additional funds to

[191] DPU 18-GSEP-04, Liberty Utilities.

[192] Under the Massachusetts Constitution, the Massachusetts AG is an elected officer in the executive branch. The AG is "an advocate and resource for the people of Massachusetts in many ways, including protecting consumers, combating fraud and corruption, investigating and prosecuting crime, and protecting the environment, workers, and civil rights." See: https://www.mass.gov/orgs/office-of-attorney-general-maura-healey

[193] As the AG Office stated during the Snapshot Review Process, it is important for the ratepayers to have their own advocate representing the ratepayers' interests in gas-related matters before the DPU. The Panel agrees and notes this role could be organized to be within the AG Office or elsewhere in the government structure.

[194] The law provides that the ratepayer advocate participates on behalf of any group of consumers in matters involving rates, charges, prices and tariffs of the Gas Companies before the DPU and to participate in Federal Energy Regulatory Commission or other Federal energy proceedings on behalf of ratepayers in the Commonwealth. See MA General Laws, Part 1, Title 2, Chapter 12, Section 11E.

[195] There are many ways to improve safety without incurring additional costs, but many of the recommendations from this Assessment, such as increasing the pace of replacement and adding more gas company inspectors to move to a 1:1 or 1:2 ratio of inspectors to job sites, cannot be timely and effectively undertaken without increasing costs to ratepayers.

[196] For instance, the AG Office relies on the expertise of an economist to analyze a Gas Company's request for an increased rate of return on equity.

[197] The AG Office supported expenditures for new training facilities and additional employees (see Bay State Gas Company [DPU 15-50]) and improvements in LNG facilities (see Berkshire Gas Company [DPU 18-40-B]).

[198] A pipeline expert would have engineering, technical, and/or operating experience. During the Snapshot Review Process, the AG Office indicated it has benefited from having an expert with significant pipeline regulatory experience as part of the team. This expert had over 20 years of experience at the DPU as an Assistant General Counsel to the Pipeline Safety Division. When this expert retired in 2019, his duties were assumed by other Assistant Attorney Generals in the AG Office. The AG Office also notes that adding a technical expert would require funding for a new full time employee on staff. It also noted that it has the statutory authority to hire outside experts to assist the AG Office, and it has done so and will continue to do so when the AG Office feels the need to do so.

improve safety on the basis of the proposed need, methods, pace, priority of work, and measures of effectiveness after implementation.

10.2.2 Costs outside the Gas Company's control could benefit from the AG's focus.

During the field visits, the Panel observed many costs of construction incurred by Gas Companies that are outside of their control. These include the costs of obtaining and following the requirements of permits from local entities, the terms, practices and fees involved in obtaining police details to provide vital traffic controls, and varied local paving and restoration requirements. To the extent within the jurisdiction of the AG office, the AG may be the best entity in a position to examine the reasonableness of all these costs.[199]

10.2.3 Placing the ratepayer advocate role within the AG Office creates a perception of added weight to its positions.

It is not uncommon for ratepayers to have an entity advocating on their behalf in rate cases and other matters before state utility commissions.[200] Having the AG Office in that role, however, has created the perception in Massachusetts that the AG's positions or arguments in any given matter deserve additional weight and deference.[201] This leads to a belief that any argument made by the State's AG Office must be addressed by all participants in a proceeding. Without having a technical expert on pipeline safety involved in formulating its arguments, the AG Office may be taking positions that result in additional resources being expended by all parties and the DPU on matters that may not be advancing pipeline safety.

10.3 Observations about the Interested Parties

While each Gas Company is accountable for safely operating gas distribution systems to reliably deliver natural gas to customers, there are a number of Interested Parties with a wide variety of key goals and objectives that impact natural gas pipeline safety within the Commonwealth. These varied goals and interests and can distract from, and result in, a reduced focus on pipeline safety and solid commitment to continually learning and improving.

10.3.1 Organizational goals can conflict with gas pipeline safety.

Each of the Interested Parties has organizational goals that can conflict with one another. These varying goals range from keeping rates affordable, adding more jobs, managing paving requirements, limiting impacts of construction on residents, and reducing greenhouse gas emissions. While these are all worthy goals, they are often in conflict and can distract from enhancing gas pipeline safety. For example, the constraints placed on increasing the pace of

[199] The DPU might also consider having Gas Companies separate costs that are outside of their control in GSEP filings and in other matters that would add transparency about (potentially otherwise undocumented) costs that are borne by ratepayers.

[200] About one-third of the US states place that role within the AG Office. Other states use a variety of other organizational approaches to provide its ratepayer with an advocate including establishing and paying for independent advocates outside of any governmental agency, or placing the advocate in a separate division within the state's utility commission. The Panel observes these approaches tend to put the ratepayer advocate on a more even footing with other participants in the proceedings before the state utility commissions.

[201] While not the only factor, the fact that a division of the AG Office has criminal enforcement powers among its many other roles may be contributing to this perception.

replacing leak prone pipe result, in part, from organizational goal conflicts. Recognizing the existence of these conflicting goals is the first step in addressing and resolving potential or perceived conflicts.

For example, the Panel observed that while risk was discussed by Gas Companies as a factor in determining when specific projects would be undertaken, the actual undertaking of a project was much more often driven by other factors including:

- Paving schedules;
- Deadlines for removal of steel plates from city streets;
- State and city water or sewer infrastructure projects; and
- Availability and timing of permits.

While these reflect important local needs, efforts need to be undertaken to understand the impact these factors are having on the ability to lower risk on natural gas systems.

10.3.2 Legislators can affect excavation safety improvements.

The DPU and the Gas Companies have undertaken numerous efforts to help manage the threat of excavation damage to buried mains and services.[202] There is room for improvement within the Commonwealth by removing the exemption of local entities from participating in Dig Safe.[203] Currently, certain entities such as municipal water or sewer companies are not required to participate in Dig Safe[204] although some wisely do.[205]

Such exemptions are not in the interest of pipeline and public safety. Yet the DPU notes it cannot require municipalities, departments of transportation, public works, sewer districts, water districts, or similar entities to participate in Dig Safe because the law has expressly exempted them.[206]

An exemption from Dig Safe has two practical impacts. It means municipal water companies do not have to locate and mark their own assets when an excavator, like a Gas Company, needs to excavate

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202 Opportunities for Gas Companies to improve by clarifying expectations about excavation practices are discussed in Section 9.1.3. The improvements made by the DPU are set forth in Section 10.1.9.

203 As noted earlier, Dig Safe® is a not-for-profit clearinghouse used by the Commonwealth of Massachusetts and the states of Maine, New Hampshire, Rhode Island and Vermont. When someone calls 8-1-1 before digging or making any excavation, Dig Safe notifies participating utility companies of these plans. In turn, these utilities (or their contract locating companies) respond to mark out the location of their underground facilities. See G.L. c. 82, §§40 through 40E. Dig Safe is a free service, funded entirely by its member utility companies.

204 See DPU 19-43-A, Order Adopting Final Regulations. While municipal water companies are not exempt from the definition of "excavators" nor are their facilities excluded under the definition of "underground facility," they are not required to be members of Dig Safe. Practically, this means they are not required to include their assets in the one-call system, nor respond to requests to mark and locate their assets in the event of an excavation near those assets. G.L. c. 82, § 40. See also G.L., Part I, Title XXII, Chapter 164, §§ 76D, which fails to name water companies when it lists those entities that must participate in Dig Safe, stating that "[a]ll natural gas pipeline companies, cable television companies, steam distribution companies and public utility companies … shall create, participate in and be responsible for the administration of a utility underground plant damage prevention system." See also, Dig Safe Rulemaking, D.P.U. 88-40, at 11-12 (1991) (discussing the issue). Note the DPU does have the authority to issue a NOPV to a municipal entity for violation of M.G.L c.82 §§40 through 40D (See 220 CMR 99.09), but it does not have authority to issue fines to local municipalities.

205 Many municipalities, departments of transportation, public works, sewer districts, water districts, and similar entities voluntarily became members of Dig Safe. See: http://www.digsafe.com/member_companies.php

206 DPU 19-43-A, Order Adopting Final Regulations (page 15).

in a location that may have buried water and sewer lines.[207] And perhaps more importantly, from a public safety perspective, it means the municipal water and sewer companies are not penalized for failure to call 8-1-1 before excavating near gas company underground assets.

Excavation damage is the leading cause of significant gas pipeline incidents in Massachusetts.[208] The following changes to the law will enhance public and pipeline safety:

- Require municipal water companies to participate in Dig Safe by responding to calls to mark its own assets; and
- Allow the DPU to fine municipal departments, especially water departments, for failure to call for a mark and locate before excavating.

10.4 Other Topics Related to Gas Pipeline Safety.

To enhance the necessary public discussion on natural gas pipeline safety going forward, the Panel briefly discusses several related pipeline safety topics (sections 10.4.1 and 10.4.3).

10.4.1 Topic Area 1. Meter Replacement Program

Gas Companies are expending notable resources, time, and focus on the Commonwealth's seven-year meter replacement program, despite limited safety benefits. Enacted in 1934, the program requires meters to be removed from service and tested every seven years. This replacement timeline is out-of-line with industry practices and current technologies; it has not been shown to generate improved gas pipeline safety. Moreover, it consumes resources that could be redirected to more impactful pipeline safety activities. The program is an inconvenience to customers; yet, these are the same customers who pay for the program.

The current meter replacement program does provide a level of assurance about meter accuracy to protect the customer from being over-billed; however, the meters that are found to be inaccurate represent only a small fraction of meters that are actually removed and tested. Most states have well established programs to protect customers from meter inaccuracy using a sampling and analysis process to identify meters that are potentially more problematic than others.

The meter replacement program also provides an opportunity for a Gas Company employee to be inside a customer's home (or business) in locations where the meter is located inside the home (or business). This offers the Gas Company an opportunity to discern possible gas risks in the home or business (e.g., leaking furnaces or gas stoves). However, these in-home safety checks are outside of a Gas Company's jurisdiction and the potential ancillary safety benefits of the seven-year meter replacement program can be met by increasing the frequency of gas leak surveys or through other programs.[209] Additionally, with GSEP moving meters (where feasible) from inside to outside homes and businesses, this potential benefit will continue to diminish.

[207] In this Assessment, the Panel learned some municipal water companies will locate and mark their facilities upon request. Of these, some charge gas companies a fee (i.e., $25 or $50) each time the water company arrives to perform the locate and mark (contrary to Dig Safe, which requires the marking company to refresh the marks upon request at no charge). This fee arrangement means a city would collect fees from Gas Companies that, in turn, are funded by rates paid by gas customer.

[208] See PHMSA incident data discussion in Section 8.3.2.1.

[209] For example, the DPU could require gas companies to conduct gas leak surveys in areas with indoor meters more frequently than currently required by regulation. Alternatively, the DPU could require gas companies to conduct an indoor leak survey

Lastly, because meter replacement involves performing live gas work and results in methane emissions with each meter change out, this work adds risk and some emissions but does not enhance pipeline safety.

10.4.2 Topic Area 2: Financial Incentives

While the Panel encountered budget concerns among the Gas Companies, the Panel found no evidence of Gas Companies making decisions that prioritize profit over safety. In fact:

1. A Gas Company puts its profits and even its existence at risk if it does not develop and maintain an appropriate focus on safety. Historically, companies that have major incidents with their assets experience significant financial penalties, business disruption, and reputation damage. For example, Pacific Gas and Electric (PG&E) experienced an extreme tragedy with a failure on its transmission pipelines in San Bruno, CA in 2010. Costs and penalties following that tragedy were over $2.8 billion. Costs related to the tragic incident in the Merrimack Valley region in September 2018 are still being incurred; the most recent data from PHMSA indicates these costs have already exceeded $700 million – with press reports indicating costs have already exceeded $1 billion.
2. The allowable rate of return for each of the investor owned Gas Companies is determined by the DPU after an intense regulatory process, which is called a rate case.[210] This regulatory process has several features that control the amount a Gas Company can earn:
    a. In this process, the Gas Company and the AG Office and other intervenors debate appropriate rates consumers will be charged, and based on the record that is developed, the DPU staff and Commission establish:
        i. The amount of operating and maintenance expenses that can be recovered in rates. For expenses other than gas supply costs,[211] the investor-owned Gas Companies receive cost recovery based on the operating and maintenance costs incurred during a specified period (known as a test year);
        ii. Those capital investments and assets on which the Gas Company can earn a rate of return. Collectively, these assets are often called the “rate base”; and
        iii. An allowable rate of return on the capital investments, or rate base. The allowable rate of return for most Massachusetts Companies is between 9% and 10%, and the actual rate of return is often lower.

    b. If the DPU, AG Office, or a group of ratepayers believe a company is over-earning in the period between rate cases, each can initiate a rate case to correct potential over-earning; and

following a customer request. The terms and conditions of providing such services, along with the rate recovery, would need to be determined.

[210] Rates for municipal owned gas utility companies within Massachusetts are not set by the DPU. Their rates are governed by other locally managed mechanisms.

[211] Massachusetts allows investor-owned Gas Companies to pass through the cost of acquiring gas supply with no profit component. The cost of gas supply typically amounts to about 60% of an average customer’s bill.

3. Because of the ability of Gas Companies to earn on capital expenditures, they are incentivized to invest more, not less, in infrastructure. That is, from a purely financial perspective, a company would prefer to replace the leak prone pipe and earn a return on that investment rather than repeatedly repair the same leak (which would cost more in terms of operating dollars).

10.4.3 Topic Area 3. Risk Tolerance

Risks arising from operating natural gas pipelines can be, and should be, managed to lower the risk, and protect against and reduce the likelihood of future incidents.

Safety can be improved and enhanced. Efforts to improve and enhance safety will lower the risks associated with operating natural gas pipelines. Risk management requires setting priorities to make decisions.

11 Best Practices for Gas Companies

During this Assessment, the Panel identified potential best practices[212] which, if adopted, would help improve pipeline safety. In addition, during the field visits, the Panel observed various Gas Companies utilizing certain approaches the Panel considers as a best practice within the industry. These practices are typically unique to each Gas Company, though some practices were employed by more than one Gas Company. To the extent that the best practices described in this section were observed at an individual company, the Gas Company is named below.[213] See these sections for categorized best practices:

- Personnel (Section 11.1);
- Job Site (Section 11.2);
- Process Practices (Section 11.3);
- Dig Safe Practices (Section 11.4);
- Asset (Section 11.5);
- O&M (Section 11.6); and
- Emergency Response (Section 11.7).

These best practices, when applied to address certain risk for a Gas Company, can help improve gas pipeline safety and reliability of natural gas supply.

11.1 Personnel Best Practices

Personnel best practices include the following:

- Use company inspectors (contractors or company employees) that are truly independent (checker versus doer) and are actively engaged observing work tasks and interacting with personnel (Berkshire and Holyoke);
- Use company-inspector-to-construction-crew ratios of 1:1 or 1:2 (Holyoke and Liberty);
- Use effective, engaged, and knowledgeable inspectors (Holyoke and Liberty);
- Use inspectors to take notes and swing ties on new installs (Liberty);
- Adopt several innovative approaches to address workforce availability and knowledge transfer concerns (e.g., two-year shadow; cadet program with college scholarships and work programs). (Holyoke and Wakefield);

[212] As discussed in footnote, 11, the phrase *Best Practices* describes a method or technique that, in the Panel's experience, has been generally accepted in the industry as being superior to alternatives because it produces results that enhance pipeline safety. The Panel's use of the phrase is not intended to suggest that there is only one correct way to perform the work; instead, it is meant to indicate a leading best practice within the industry. Best practices or leading best practices should continue to be developed over time based on organizational learnings

[213] Naming one Gas Company does not mean that practice is employed solely by that company, but rather that the Panel observed that Gas Company was utilizing it.

- Use grading system (i.e., A, B, C, and D) to rate qualification of field technicians *A* technicians had the most experience and generally led crews. *D* technicians often were new to the field and likely would have minimal Operator Qualified tasks completed. Field crews would have at least one *A* technician and *B* technician. Depending on the tasks, possibly one or more technicians with a *C* or *D* designation would be added to the crew (Eversource and National Grid);
- Require all personnel wear basic personal protective equipment (PPE) including hard hats, steel-toed boots, safety vests, safety glasses, and gloves when on a job site, regardless of task being performed at the site (Berkshire, Eversource, Holyoke, Liberty, and National Grid);
- Require personnel wear gas monitors on their hard hats while on work sites (National Grid);
- Prohibit cell-phone on work site (distraction to workers) (Middleborough);
- Carry a card using a QR code to display tasks for which individual is Operator Qualified to perform (Eversource and National Grid); and
- Have crew perform stretching exercises before engaging in physical work day (National Grid Contractor).

11.2 Job Site Best Practices

Job site best practices include the following:

- Read the street;[214]
- Hold effective tailgate/job briefings on the job site before work begins and complex tasks are undertaken (Berkshire, Eversource, and National Grid);
- Use electronic means (e.g., iPads, laptops) to display and input data in the field (Berkshire and Eversource);
- Have executives and senior leadership perform random field visits (e.g., are personnel doing what management thinks they are doing?);[215]
- Position trucks and heavy equipment, including backhoes, to protect workers from traffic (Eversource, Holyoke, and National Grid);
- Use site-specific work plans and checklists, especially at complex sites (National Grid) and to check adherence to procedures in the field (Middleborough);
- Develop and use a “lift plan” for crews that need to move heavy joints of pipe or other heavy assets (National Grid Contractor);
- Use rock shield at the bottom of the ditch before putting pipe in ditch (Liberty);
- Use a guidance safe stick when lifting steel plates at work sites (National Grid Contractor);

[214] The Panel observed this Best Practice employed by competent crews across all most all of the Gas Companies. See Section 9.1.2 for description of the skills involved.

[215] During site visits, the Panel encountered a number of individuals in supervisory roles at various Gas Companies and senior leadership from Middleborough. Their presence appeared to be related to the Panel’s activities rather than related to random field visits to assess on-site activities. See Appendix B.7.3, Middleborough.

- Use an underground leak classification criteria card for consistent grading of leaks (Eversource). See Appendix B.4 for a photograph;
- Use of pre-fabricated distribution regulator stations (National Grid Contractor);
- Pouring sand on the pavement to preserve skid steer tires and protect road pavement (National Grid Contractor);
- Using a brass hammer to reduce possibility of sparks in excavation (Holyoke); and
- Saw, cut, and remove the pavement all at once. Then, install a thin layer of asphalt over the cut area to be removed each day to accommodate that day's work (National Grid Contractor).

11.3 Process Practices

Process best practices include the following:

- Conduct leak surveys more frequently than required by regulation (Liberty);[216]
- Repair Grade 2 leaks faster than required by regulation based on potential consequences (Middleborough[217] and Unitil);
- Effectively use strong, competent contractor crews on complex jobs (Berkshire, Eversource, and National Grid);
- Use of pre-fabricated distribution regulator stations (National Grid);
- Report, track, and review all over-pressure events daily;[218]
- Develop list of critical gas events, investigate events to extract learnings, share information learned with organization; [219]
- Involve gas control with complex site-specific procedures (e.g., verify field gage pressure) (National Grid);
- Avoid static electricity with purge procedures and follow requirements to avoid air-gas-static that creates a fireball (National Grid procedure);
- Integrate paper records into a Geographic Information System (GIS), use GIS for all recordkeeping, and make GIS data available and easy to update in the field;
- Upgrade LNG facilities to prepare for peak shaving and potential supply shortages (Liberty);
- Find the right balance on the number of procedures; too many can hinder thinking about and managing bigger picture;[220]

[216] The purpose of a gas leak survey is to inspect portions of gas systems to determine if a leak is occurring. Gas leak surveys can be accomplished through various means of labor and technology. In general, PHMSA and state regulations require gas leak surveys be conducted on a specified interval based on location (i.e., being inside or outside of a business district) and types of pipe materials. For example, operators are required to conduct a gas leak survey inside a business district once every calendar year, but not to exceed once every 15 months. Increasing leak survey frequency reduces risk for certain pipe types and conditions. For example, leak surveying an area with cast iron pipe after frost-in and frost-out (fall and spring, respectively) identifies leaks that might have occurred from ground movement caused by frost heave.

[217] Middleborough repairs all discovered Grade 2 and Grade 3 leaks in the year in which they are discovered.

[218] While the Panel did not observe this, it is a best practice for the Gas Companies to consider.

[219] Id.

- Attend NGA Gas pooling calls in circumstances when gas supply is limited;[221]
- Active participation in industry associations to access broader perspectives and best practices (Wakefield); and
- Be a learning organization (Holyoke, Eversource, and National Grid).

11.4 Dig Safe Practices

Dig Safe best practices include the following:

- Use clear flags to show personnel arrived to locate and mark gas facilities, and found none to be present (Eversource; see photograph in Appendix B.4.7);
- Mark new main/service after installation (and before paving) to account for lag in updating records (Liberty and National Grid);
- Use vacuum truck to excavate in areas with complex buried infrastructure (Eversource) or other means – like an air knife in combination with a vacuum truck (Liberty);
- Maintain good legacy records (Blackstone, Holyoke, Middleborough, and Unitil);
- Notification of municipal water departments before excavating to confirm water lines are marked (Wakefield);
- Positively confirm with excavator following an 8-1-1 call that the Gas Company has confirmed no gas lines are present in the area (Wakefield);[222]
- The *O&M Manual* explicitly includes documenting conversations between excavators and company staff in the Dig Safe Program (Columbia Gas);[223]
- Hand dig all crossings before starting excavation of a trench (National Grid Contractor); and
- Install cones near crossings to increase visibility of the excavator operator (National Grid Contractor).

11.5 Asset Best practices

Asset best practices include:

- Outside meters with regulators;
- Installing excess flow valves on lines above 22 psig;
- Setting monitors at regulator stations below MAOP (Unitil);

[220] While the Panel did not observe this, it is a best practice for the Gas Companies to consider.

[221] This appears to be a practice broadly used by the Gas Companies to address potential supply shortages. The Panel learned of it at National Grid.

[222] As discussed in Section 10.1.9, positive contact between the Gas Company and the excavator has been adopted in Massachusetts by the DPU. See DPU 19-43-A (Order Adopting Final Regulations) modifying 220 CMR 99.00 (adding a new provision requiring companies that receive notification of an excavation from the Dig Safe Center to affirmatively inform the excavator or otherwise indicate if they have no underground facilities within the safety zone).

[223] This requirement appears to be broader than the positive identification required by DPU when no lines are present.

- Enhance gas systems resiliency by adding and upgrading key assets to enable consistent operation under MAOP, especially for low-pressure systems; and
- To the extent possible, replace all low-pressure systems with medium- or higher-pressure systems, which will enable installation of safety devices (regulators and excess flow valves) on service lines to homes and businesses.

11.6 O&M Best Practices

Best practices set forth in O&M include the following:

- Inspect valves every five years;
- Set monitors below MAOP;
- Acquire guidance as to when to install SCADA, monitor inlet/outlet pressure at every station; and
- Set clear expectations for regulatory maintenance, including when full tear down and soft goods replacement is required (National Grid).

11.7 Emergency Response Process Practices

Emergency response process best practices include the following:

- Conduct regular mock exercises/drills, inclusive of external partners (National Grid and Eversource);
- Assign emergency response roles when hiring personnel and conduct emergency response training as part of the initial on-boarding process for new employees (Eversource); and
- Provide vests in the Incident Command Center with roles emblazoned on the backs for team members to wear when the Incident Command Center is activated (Eversource).

12 Recommendations

Based on the observations in this Assessment, sections 12.1 to 12.3 contain Panel recommendations for consideration by the Gas Companies, State Agencies, and Interested Parties.

12.1 Massachusetts Gas Assets

Related to Massachusetts gas assets, the Panel recommends the Gas Companies and those beyond the Gas Companies, undertake efforts to accomplish the following:

1. Accelerate the pace of replacing the leak prone pipe – prioritized to reduce leaks rates, especially for Gas Companies with leak rates that appear to be increasing (but only if Gas Companies can do so safely);
2. Enhance gas systems' resiliency by adding and upgrading key assets to enable consistent operation under MAOP, especially for low-pressure systems; and
3. To the extent possible, replace all low-pressure systems with medium- or higher-pressure systems, which will enable installation of safety devices (regulators and excess flow valves) on service lines to homes and businesses.

12.2 Gas Companies

4. Visit the field more often with senior leadership to better understand the activities and barriers that routinely occur;
5. Ensure the company develops and enforces a consistent policy for personal protective equipment (PPE) for all personnel working at or visiting the job site as it serves as the foundation for safety culture;
6. Mature damage prevention programs beyond managing 8-1-1 calls (locating and marking assets) to be a more comprehensive mission critical programs, which include conducting investigations, and developing and implementing lessons learned;
7. Set and enforce clear expectations regarding excavation with mechanical means, undertake efforts to understand why deviations are occurring in the field, and revise O&M manuals to recognize challenges in the field;
8. Adopt and use site-specific step-by step procedures and checklists, especially for more complex jobs;
9. Develop a practice comparable to a "Time Out for Safety" when change to a workflow is introduced at the job site to consider its impacts and plan accordingly;
10. Broaden integrity management plans beyond leak prone pipe replacements to fully consider other threats (including incorrect operations);
11. Enhance the role and responsibilities of the Gas Company inspectors, and ensure training and experience provides appropriate qualifications. Consider using inspectors on a 1:1 or 1:2 ratio on job sites to provide the level of interaction between crew and inspector at a work site that adds value and enhances safe execution of the work;
12. Encourage management and leadership to embrace learning and develop more self-critical evaluations that ask: What do I see? What am I missing? How can we improve?

13. Conduct a safety culture assessment using a multi-method approach such as the one set forth in Appendix A.3 (see the White Paper in Appendix A);
14. Report all over-pressure events on low-pressure systems that require post-event action to DPU and PHMSA. More specifically, these events should be considered significant in the judgment of the operator under 49 CFR 191.3 (3);
15. Conduct an RCA for every critical gas event, including, but not limited to, unplanned outages, operator error, excavation damages, near-misses, over-pressure events on a low-pressure system that require post-event action with rigorous review to consider *bigger picture* issues, develop lessons learned, enact and track lessons learned and measure effectiveness of changes;
16. Establish programs and training for process safety hazard identification in the field, specifically for live gas work, and most likely in the context of conducting regular and effective pre-job briefings to:
    a. Change the mindset of personnel in the field regarding potential risks of work;
    b. Encourage personnel to actively look for and identify hazards to the gas system before starting field work; and
    c. Promote a continued focus on personal and public safety, with compliance in mind.
17. Require contractors to have safety programs that meet or exceed Gas Company requirements and perform external/independent audits of contractor's safety programs;
18. Improve records and data management systems, focusing on improving quality, accessibility, and timely updating of records based on findings in the field;
19. Recognize the value of leadership in the field personnel, specifically for crew leads, through training, incentives, and other mechanisms;
20. For companies that operate both electric and gas systems, separate the leadership to ensure these businesses maintain sufficient focus on, and retain the expertise for, correct gas pipeline operations;
21. For companies with LNG plants, implement a robust integrity management program for LNG facilities to ensure continued fitness for service given their significant contribution to meeting customer demands on a peak day and providing sufficient natural gas distribution supply to mitigate operational risks, if not already in place;
22. Consider adopting the best practices in Section 11; and
23. Treat emergency response as a core competency and take steps to improve Gas Company emergency response plans, including:
    a. Develop and incorporate a common understanding of the Incident Command System (ICS), including communication protocols, common terminology, and accountabilities for each ICS function and role;
    b. Identify individuals and appropriate training protocols for each function, and implement appropriate training. Consider assigning roles and starting emergency role training immediately after personnel are hired;
    c. Conduct more tabletop and field emergency response preparedness drills, including:
        i. Consult a third party to organize and grade the drills;

ii. Exercise a unified command structure and mutual aid with Gas Companies, fire departments, and government;

iii. Consider communication protocols and technology needs; and

iv. Follow up with a lessons-learned session for all participants to develop next steps for continued improvement.

d. Identify and address gaps, benefits, and limits to mutual aid during a gas emergency; and

e. Ensure the ICS identifies roles and responsibilities with outside parties such as fire departments, police departments, local and state representatives, and the media.

12.3 Beyond Gas Companies (State Agencies, Stakeholders, Interested Parties and Industry)

The Panel recommends the following:

24. Agree upon common goals and develop a collaborative approach to consider further accelerating pipeline replacement. This includes:
    a. Involving all stakeholders;
    b. Collaborating to address the primary barrier of access to a qualified workforce; and
    c. Assessing risks of all potential changes to the pace of replacement.
25. Evolve the operator qualification program to, not just certify gas personnel when they pass the test, but also confirm they are qualified and competent to fully understand the hazards and perform the work safely;
26. Use discovered leak data[224] from Gas Companies to confirm that pipe replacements are occurring at the right locations and at an acceptable pace;
27. Enhance GSEP to:
    a. Expand consideration of pipe (mains and services) for replacement beyond the current GSEP definition prioritized to reduce risk.
    b. Enhance the metrics used in GSEP to evaluate and encourage appropriate main and service replacements. Factors to consider include:
        - Leak rates of the project based upon discovered leaks;
        - Consequence of a release (e.g., on hard surfaces, near people); and
        - Rate of replacement (e.g., a few feet per day or 200 to 300 feet per day).
    c. Continue to increase the use of waivers for rate recovery beyond currently authorized percentage when warranted by increased risk reduction activities;[225]

[224] As noted in the National Grid snapshot (see Appendix B.8.4), it is important for the DPU to provide specific guidance on how a Gas Company should account for a leak in which the cause and location (main or service) are unknown. The Panel opted to categorize such leaks as *leaks occurring on the main*. See Footnote 57, and the discussion in National Grid's Snapshot in Appendix B.8.4.

   d. Increase transparency to the Gas Company prioritization process to encourage undertaking difficult projects that lower risk, earlier; and
   e. Decrease required time and effort for all parties during the GSEP filing and reconciliation process.

28. Enhance DPU processes to:
    a. Set and meet appropriate response timelines for enforcement actions;
    b. Increase transparency as a guiding principle for DPU's Division of Pipeline Safety actions and the status of those actions;
    c. Provide Gas Companies sufficient time after an inspection or other enforcement action to identify, develop, train, and then execute corrective actions (which, at the discretion of the DPU, may be supervised by the DPU or a third-party) before taking additional punitive action;
    d. Use penalty authority clearly and with purpose when Gas Companies act deliberately, recklessly or with disregard in the face of learning opportunities; and
    e. Publish an on-line list of excavators that repeatedly fail to call 8-1-1 and damage underground facilities. Include the amount of each penalty in the publication as a deterrent.
29. Undertake a review of all risks related to the substantial reliance upon LNG as a source of supply to meet the peak demands for natural gas in the Commonwealth, including whether Gas Companies are utilizing an appropriate integrity management plan for those facilities;
30. Adopt safety culture principles, which include a cooperative learning approach to working with Gas Companies rather than a punitive approach, to achieve better results over the long term;
31. Broaden the focus of all parties to go beyond minimum compliance mandated by federal and state pipeline safety regulations;
32. Ensure that pipeline safety is a significant consideration across all relevant government agencies, divisions, and/or departments, including in the AG Office and in the ratemaking process;
33. Further consider organizational goal conflicts in the context of pipeline safety and how best to collaboratively resolve them;
34. Assess accountability and responsibility across government agencies, divisions, and/or departments, especially related to matters before the DPU and in energy transition plans;
35. Consider providing additional financial resources to enhance recruitment and retention of individuals with pipeline safety experience and expertise in government agencies, divisions, and/or departments. Especially consider providing additional resources to DPU (to enhance recruitment, training, and retention of qualified inspectors, and tracking and transparency in electronic systems), and to the AG Office to enable hiring pipeline safety experts;

[225] The Panel recognizes and applauds DPU's recent decision to increase the amount Gas Companies can recover for GSEP work from a cap of 1.5% to 3.0%. In this recommendation, the Panel recommends the DPU permit Gas Companies to recover costs when warranted by risk reduction activities, even if that requires a waiver of the current cap of 3%.

36. Consider extending the meter replacement program beyond seven years:
    a. Use moving meters outdoors in GSEP (where feasible) as an opportunity to re-evaluate costs and safety impacts;
    b. Recognize this is an opportunity to demonstrate the ability of Gas Companies and Interested Parties to collaborate and resolve an issue;
    c. Address meter accuracy concerns and perceived indirect safety benefits separately. Evaluate the following:
        i. Meter accuracy for consumer protection, with safety in mind;
        ii. Indirect safety benefits may include ad-hoc gas inspections inside residences and could be managed without removing meters; and
        iii. Consider developing separate inspection programs, as necessary, to address issues that may be opportunistically identified as part of the meter program.
37. Specifically consider gas pipelines, the reliance on LNG, and gas pipeline safety in the transition plan to achieve an 80% reduction of greenhouse gases by 2050, including the following:
    a. Any transition plan should consider pipeline and LNG risks, and societal impacts (public safety and pipeline safety); and
    b. Ensure that energy transition policies and regulations fully consider gas pipeline and LNG safety and impacts that may increase risk.

Appendices to the
Statewide Assessment of Gas Pipeline Safety Final Report

Appendices

Appendix A Safety Culture White Paper

Safety Culture White Paper

Final Report

Document type	White paper
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Prepared for	Commonwealth of Massachusetts, Department of Public Utilities
Project number	19DPUWGAMY4
Prepared by	Dynamic Risk Assessment Systems, Inc.
Project number	BD-19-1033-DPU01-DPU01-31885
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A.1 Introduction

This *White Paper* provides an overview of the current state of knowledge in safety critical industries, such as natural gas pipelines, about the concept of "Safety Culture." In addition, the paper provides some examples of strategies to improve safety culture.

The body of knowledge and evidence that this paper draws upon comes from a wide range of safety critical industries. However, the concepts are broadly applicable and have been introduced in the pipeline industry in more recent years.

A.2 Nature of Safety Culture

A.2.1 Importance of Safety Culture

Safety culture is a concept that is used to explain why organizations with complex safety systems and engineering controls continue to fail in preventing major incidents. After every major safety incident, people ask the question - how could this happen? The hazard was known; people knew what to do, and there were supposed to be control measures in place to prevent this event from happening. And yet it did.

After the Chernobyl nuclear incident in 1986, the term "Safety Culture" was coined to describe the fundamental challenge of ensuring safe operations in complex, safety critical technical systems that are operated by people who, by their very nature, make mistakes.

While the common view is that Chernobyl, as well as other subsequent major industrial safety incidents occurred because the people within the organization did not do what they were supposed to do, the truth is more complex. These failures occurred, not simply due to the errors of people operating the plant, but as a result of a broader degradation of the management systems and the existence in the organization of a poor safety culture.

For example, a review of 17 petrochemical safety incidents[226] concluded that four safety culture threats (complacency, tolerance of inadequate systems, normalization of deviance and production pressure) were identified as contributory factors. There is also evidence that employee perceptions of safety culture are correlated with safety performance indicators[227] and injury rates.[228]

The safety culture of an organization determines two important keys to safe operations of safety critical systems. First, it determines the effectiveness of safety management systems. Second, it determines the gap between described control measures and the implementation of these controls.

Reviews of major safety incidents consistently conclude that effective control measures were available to control the hazard that caused the safety incident, but were either not adopted by the organization or, more often, the control measures were not implemented as intended. Both of these findings reflect a poor safety culture, as the organization did not allocate adequate resources to safety management nor did it ensure appropriate controls were in place and effective.

[226] Fleming, M. & Scott N. (2012) Cultural disasters: Learning from yesterday to be safe tomorrow. *Oil and Gas Facilities*, Vol 1, No 3 (June). Society of Petroleum Engineers. Houston, Texas

[227] Morrow, S & Koves, G. & Barnes, V. (2014). Exploring the relationship between safety culture and safety performance in US nuclear power operations. *Safety Science*. 69. 37–47. 10.1016/j.ssci.2014.02.022.

[228] Clarke, S. (2006) The relationship between safety climate and safety performance: a meta-analytic review. *Journal of occupational health psychology* 11 (4), 315-27

In addition, warning signs of a problem typically have been ignored. It can appear (with the benefit of hindsight) that the organization suffered from collective blindness, as they did not see how far practice had deviated from the plan.

A.2.2 Safety Culture Definition

There are many different definitions of Safety Culture. No single universally-accepted definition or pipeline specific definition of Safety Culture exists. This lack of a clear and agreed-upon definition is, in part, one of the reasons for the popularity of safety culture. The ambiguity of the term means everyone can agree that safety culture is important, without having to agree on the specifics of what it means or what action it requires an organization to undertake. Management often views safety culture as equivalent to employee safety attitudes, behavior or ownership for safety, while employees view safety culture as management's commitment to safety or resources.

Several organizations have provided usable definitions of Safety Culture including the following with their respective definitions:

- **U.S. Department of Transportation (2011)**, under which the Pipeline and Hazardous Materials Safety Administration (PHMSA) operates and regulates gas distribution pipelines:
  - The shared values, actions, and norms that demonstrate a commitment to safety over competing goals and demands.[229]
- **Canada Energy Regulator** (formerly Canada's National Energy Board) (CER)[230] which regulates pipeline safety in Canada:
  - Safety Culture: Canada's CER has adopted definition of Safety Culture from (Mearns et al (1998) which is "the attitudes, values, norms and beliefs, which a particular group of people shares with respect to risk and safety." (p. 239)[231]
- **US Nuclear Regulatory Commission (NRC)**, which is an independent agency of the US government tasked with protecting public health and safety related to nuclear energy:
  - "The core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment."[232]
- **US Bureau of Safety and Environmental Enforcement (BSEE)**, which regulates the US offshore energy industry:
  - "The core values and behaviors of all members of an organization that reflect a commitment to conducting business in a safe and environmentally responsible manner."[233]

[229] https://rosap.ntl.bts.gov/view/dot/32538

[230] The *Canadian Energy Regulator Act* replaced the *National Energy Board* (NEB) with the CER, effective August 28, 2019.

[231] Mearns, K., Flin, R., Gordon, R. & Fleming, M. (1998). Measuring safety culture in the offshore oil industry. Work and Stress, 12(3), 238-254. "Safety" includes safety of workers and the public, process safety, operational safety, facility integrity, security and environmental protection.

[232] https://www.federalregister.gov/documents/2011/06/14/2011-14656/final-safety-culture-policy-statement

[233] https://www.federalregister.gov/documents/2013/05/10/2013-11117/final-safety-culture-policy-statement

- **American Petroleum Institute (API)**, which represents the US oil and natural gas industry:
    - "The collective set of attitudes, values, norms, beliefs and practices that a pipelines operator's employees and contractor personnel share with respect to risk and safety"[234]

The definitions listed above are all different, yet they all describe safety culture as consisting of shared values, attitudes and perceptions that determine safety performance. The similarities in definitions reflects how safety culture is manifested in practice. One of the important aspects of safety culture is that it determines what is meant by "safety." For example, in some organizations, safety is understood to be limited to occupational safety. This is often reflected in the use of occupational injuries as the primary or sole safety performance indicator. In these organizations discussions about safety are limited to employee safety and additional terms are required when considering hazards that may impact the public (e.g., process safety). In these organizations, employees could have very positive perceptions of commitment to safety, while at the same time having concerns about process safety.

A.2.3 Safety Culture Framework

There are several safety culture frameworks that have been developed across various safety critical industries. Each identify some of the key indicators of safety culture. Generally, there is alignment between them, and a comparison of some these safety culture frameworks, relevant to the natural gas industry, are shown in Figure A-1.

Using the metaphor of a house to describe a safety culture framework, Figure A-1[235] illustrates the four indicators of a positive safety culture (i.e., supportive elements) and four indicators of a negative safety culture (i.e., destructive elements).

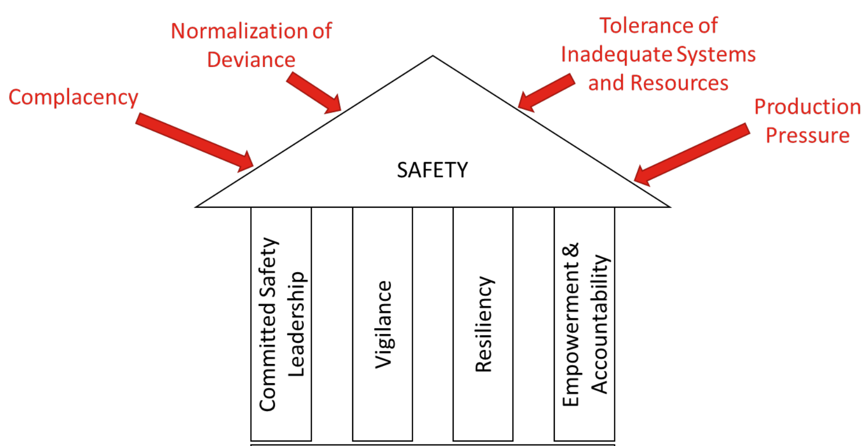


Figure A-1: Illustration of a Safety Culture Framework

[234] API Recommended Practice 1173, Pipeline Safety Management Systems, July 2015, page xi.
[235] This is the same model used by the *Canada Energy Regulator*.

Indicators of positive safety culture are supportive and can enhance safety. These are:

- **Committed Safety Leadership** occurs when safety is an organizational value demonstrated by a genuine leadership commitment and expressed by providing adequate resources, systems, and rewards to serve this end.
- **Resiliency** occurs when there is capability to respond effectively to changing demands in order to manage potential or emerging risk.
- **Vigilance** occurs when there is an organizational preoccupation with failure and the willingness and ability to draw the right conclusions from all available information.
- **Empowerment & Accountability** occurs when accountabilities and responsibilities for safety are clearly established and documented at all levels of the organization. Ownership for safety outcomes is present at all levels and functional areas of the organization.

Indicators of positive safety culture are destructive and can undermine safety. These are:

- **Production Pressure** occurs when production is given priority over safety or when safety margins are reduced to lower cost or save time.
- **Complacency** occurs when there is a widely held belief that all possible hazards are controlled and the organization has forgotten to be afraid resulting in reduced attention to safety.
- **Normalization of Deviance** occurs when it becomes generally acceptable to deviate from safety systems, procedures, and processes.
- **Tolerance of Inadequate Systems and Resources** occurs when it becomes acceptable to work with inadequate systems and resources, which often occurs when the organization tries to do too much with too little.

A.2.4 Safety Culture Strength

Every organization has a safety culture., It can be characterized by the positive and negative indicators as discussed in Section 7. Another aspect to culture (of any type) is whether it is strong or weak. A strong culture is consistent throughout an organization, whereas a weak culture can vary from team to team, department to department, region to region. As illustrated in Figure A-2, a safety culture that has predominantly positive indicators and is consistent is ideal, where it is socially unacceptable to be unsafe anywhere in the organization.

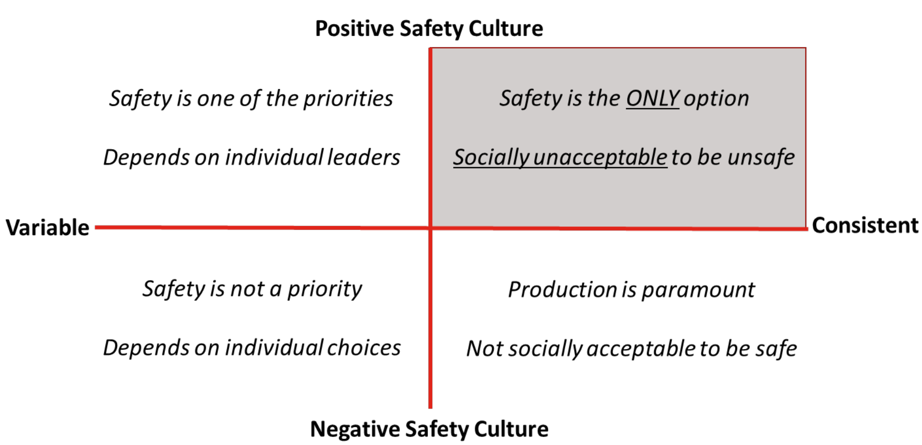


Figure A-2: Safety Culture Strength

A.2.5 Organizational Level Construct

As noted in the definition section above, safety culture is the ***shared or collective*** safety attitudes, values, norms, beliefs and practices. Safety culture is shared by a group of people and therefore needs to be managed at an organizational rather than individual level. For example, it is incorrect to say that a person has a poor safety culture, as culture must be shared by the wider group. Although individuals vary in their attitudes to safety, the safety culture of the group determines the acceptable limits for the members. If a person with a poor attitude to safety joins an organization where safety is a core value, then they will need to conform to the accepted norms and change their attitude or leave the organization. The power of culture is in the way it influences people to conform to the accepted cultural norms.

Although safety culture assessments (see Section 4) often involve capturing employee safety perceptions, these assessments often fail to provide an accurate picture of an organization's safety culture, because culture is so much more than individual employee attitudes and behaviors.

A.2.6 Key Concepts

It is important to understand the breath of safety culture, as often various stakeholders and regulators have different understandings of the term safety culture. The recent popularity of safety culture has resulted in the misuse of the term, and now it often used to simply refer to employee attitudes to safety. The focus on employees' attitudes can result in organizations trying to persuade employees to have different attitudes and not addressing the wider cultural issues, such as management commitment, learning and performance monitoring. In addition, the increasing misuse of safety culture within occupational safety has resulted in a desire to make a distinction between occupational and process safety culture. Since safety culture has always been concerned with major hazard risk[236] and only more recently has it been adopted by occupational safety experts, process safety culture is not used in this report. The distinction is unnecessary and is inconsistent with the long history of safety culture. While an organization's focus on keeping its employees safe while performing work is important, it is not the same as having a focus on improving an organization's safety culture. Safety culture influences occupational injury risk, but an organization's safety culture is a more critical factor in managing major hazard risk. A better approach to understanding the distinction is referring to safety culture for managing major hazard risk and using the term "safety climate" for discussing occupational safety and prevention of workforce injuries.

Another common misunderstanding is that organizations with good occupational injury statistics have a good safety culture. While this may be the case, it is also possible that the organization has a poor safety culture overall, since they focus their safety efforts on occupational injury rather than identifying and managing management systems and controls to address major hazard risks. For example, an organization could have good occupational injury statistics, while at the same time not undertaking required maintenance, which increases risk of a major event.

The absence of occupational injuries provides little information about an organization's safety culture. It is therefore important not to equate the absence of injury with a good safety culture. Instead organizations should use the assessment tools available to assess their safety culture.

[236] Recall that the phrase *safety culture* was first used as a causal factor in the Chernobyl disaster.

A.2.7 Relationship Between Safety Culture and API RP 1173

In 2015, the American Petroleum Institute published Recommended Practice 1173 ("API RP 1173") to provide guidance to pipeline operators for developing and maintaining a pipeline safety management system (PSMS) which is a comprehensive and systematic approach to manage complex pipeline operational activities with safety impacts. The Plan-Do-Check-Act (PDCA) cycle is at the core of the PSMS, and applied to processes within the system and is maintained to achieve continuous improvement in pipeline safety

According to API RP 1173, a positive safety culture is essential to an organization's performance, and can exist without a formal PSMS, however an effective PSMS cannot exist without a positive safety culture.[237]

This means that it is not enough to adopt API 1173 and assert the organization is safer because it has adopted a safety management system. Instead, an organization must actively work on assessing its own safety culture and work consistently to improve and strengthen its safety culture.

A.3 Assessing Safety Culture[238]

It is generally accepted that if you can't measure something, then you can't manage it, therefore it is important for leaders to understand safety culture measurement options. Yet, there is considerable debate among experts about the extent to which safety culture can be measured. Safety culture is an abstract concept. This means it is not directly observable and therefore cannot be measured like other business outcomes. In practice, we do not directly measure the culture; instead we assess indicators of the culture and use these indicators to make inferences about the culture. It is therefore more appropriate to use the term assessment rather than measurement.

A.3.1 Methods

As discussed in API RP1173, a multi-method approach is recommended to assess safety culture, in order to produce a comprehensive picture.[239] Typically, this multi-method approach might include:

1. Assessing employee perceptions, reviewing safety system documents, and conducting workplace observations. Employee perceptions can be captured via questionnaires, interviews, and focus groups.

   Caution, however, is necessary when using employee perception surveys (e.g., self-completion questionnaires), which are often used to assess safety culture. These surveys can appear to be measuring safety culture precisely, as they produce numerical values and statistical results. In reality, these surveys are assessing employees' perceptions of the culture, which is different from assessing the entirety of the safety culture itself.

   Because employee perceptions are prone to a number of biases and only tap into one aspect of the culture, it is often useful to combine questionnaires with either interviews or focus groups. This combination of input helps with interpreting the questionnaire results.

[237] API Recommended Practice 1173, Pipeline Safety Management Systems, July 2015, page xi.
[238] This section was adapted with permission from A Leaders Guide to Safety Culture (2015) by Dr. Mark Fleming.
[239] API Recommended Practice 1173, Pipeline Safety Management Systems, July 2015, page 16.

2. Conducting a systematic review of safety system documents can also provide insight into the stated values of the organization. These documents outline the key safety responsibilities for managers, supervisors, and employees.

   These reviews can highlight inconsistencies between stated values and practical arrangements. For example, an organization may state that safety is a line responsibility, yet the document review shows that the vast majority of safety activities are performed by the safety department, with little involvement of line managers.

3. Worksite observations can provide insight into the culture in action. It is possible to observe the extent to which employees comply with safety rules and deal with problems they encounter. By observing meetings, it is possible to gain insight into the way safety is considered and how important decisions are made.

These three approaches view safety culture from a different perspective and therefore provide a more comprehensive assessment of the culture.

A.3.2 Interpreting Results

Some of the results from the three approaches will be consistent with each other, while other results will be in conflict. When two results are in conflict, then it will be necessary to conduct further investigation to understand why there were conflicting results. For example, it is possible that employees may report a high degree of compliance with rules and procedures in the questionnaire, yet workplace observations may find numerous rule violations. Follow-up interviews may reveal that employees considered the observed rule violations as 'minor infractions' and not violations.

Integrating the results of the three safety culture assessment perspectives requires some expertise. Even if an organization decides to assess their culture from only one perspective, it will still require some expertise in interpreting the results. It is important not to accept the results at face value.

A.3.3 Phases of Assessment

Organizations should adopt a systematic approach to safety culture assessment. There are five broad phases to conducting an assessment, as shown in Figure A-3.[240]

Figure A-3: Safety Culture Assessment Phases

[240] This model is similar to one use in other safety culture documents including those used by the *Canada Energy Regulator*.

In Phase 1, organizations need to create an assessment team. This team should include representatives from key stakeholders, such as employees, supervisors, managers and contract managers. This team will need some education about how to conduct a safety culture assessment, even if they are using an external provider.

In Phase 2, the assessment team will need to decide on how to conduct the assessment, including what tools to use, the scope of the assessment and the resources required.

Phase 3 is the data collection phase. This may involve surveying employees, conducting interviews, reviewing documents, and conducting observations.

Phase 4 involves interpreting the data from phase 3. It is possible, that the results may raise further questions which require clarification, thus requiring additional data collection. The result of phase 4 should be a rich picture of the strengths and weaknesses identified.

Phase 5 involves using the results to create an improvement plan, as the purpose of assessment is improvement. The improvement plan should build on the strengths identified and address any weaknesses.

A.4 Influence of Safety Culture on Safety Improvement

A.4.1 Collaboration

The systems involved in design, construction, and operation of natural gas distribution infrastructure are large and complex, with many interdependencies between people, processes, and the physical pipelines, equipment and technology. The people involved include, but are not limited to, the gas companies, both management and employees; manufacturers; contractors; the regulator; and the public. These systems are often tightly coupled, use advanced technology, and evolve and change.

The result of complexity, is that safety issues are more likely to involve interactions between the other parts of the system, including the human interactions. To make the system less error prone and more error tolerant requires System Thinking.

System Thinking is understanding how an improvement in one subsystem of a complex system may affect other subsystems within that system. Understanding is enhanced by collecting, analyzing, and sharing information through collaboration of everyone involved in a complex system. The extent to which organizations collaborate in the interest of improving safety is a gauge of safety culture. Negative safety culture deters collaboration while positive safety culture supports collaboration, and some examples of this are shown in Table A-1.

Table A-1: Negative Safety Culture Deters Collaboration; Positive Safety Culture Supports Collaboration

Deterring Collaboration	Negative Safety Culture Indicator	Supporting Collaboration	Positive Safety Culture Indicator
Thinking that it's "someone else's" problem. Ignoring problem.	Complacency	See any failure as everyone's failure.	Empowerment and Accountability Vigilance
Fear of retaliation or punitive action if open and honest about issues	Complacency	Trust, open and honest communication, without fear of punitive actions	Empowerment and Accountability Vigilance
Not having all of the right people involved	Complacency	Anyone that is involved in the system is involved in identifying the problem and solutions	Empowerment and Accountability Vigilance
Participants have competing interests	Production Pressure	Everyone's interests are considered Trust good intentions of the other (the focus is system thinking not another agenda or interest)	Empowerment and Accountability
Not seeing any implementation of past collaboration efforts Solutions aren't effective (didn't involve employees)	Production Pressure Tolerance of Inadequate Systems and Resources	Prompt and willing implementation of safety recommendations	Resiliency

A.4.2 Example of Collaborative Safety Improvement in the Aviation Industry

The aviation industry is well known for its' complex systems and impact on public safety. A good example of collaboration that has resulted in significant improvement in safety for the aviation industry is the Commercial Aviation Safety Team (CAST).

After several events in the 1990s, safety officials realized that with the growth in air traffic, a corresponding increase in aviation safety was needed. In 1997, the FAA and aviation industry came together and founded CAST, with a goal to significantly increase public safety by adopting an integrated, data-driven strategy to reduce the fatality risk in commercial air travel. CAST is a voluntary cooperative Government-Industry initiative and is co-chaired by the Federal Aviation Administration (FAA) and the Industry, and its members include government agencies, employees, manufacturers and other industry stakeholders, and observers (like, the National Transportation Safety Board). It is reported that implementing safety enhancements reduced fatality risk in commercial air travel by 83% from 1998 to 2008.[241]

[241] https://www.cast-safety.org/apex/f?p=102:1:16582478008988::NO::P1_X:history

In general, the collaborative safety improvement process used by CAST is as follows:[242]

- Analyze safety data/information.
- Identify hazards and underlying contributing factors.
- Develop specific safety enhancements to address risk.
- Voluntarily implement cost-effective safety enhancements.
- Track implementation and continuously monitor the effectiveness of the safety mitigations.
- Use knowledge gained to continually improve the aviation system.

The collaborative safety improvement implemented by CAST in the aviation industry is applicable to other safety critical industries.

A.5 Strategies to Improve Safety Culture

Organizations have different safety cultures. As such, it is not possible to provide a list of specific safety culture improvement strategies applicable to each organization. Instead, each organization needs to determine the best approach to improve its own safety culture. To assist in developing potential Improvement strategies, there are four positive safety culture indicators (Leadership, Empowerment and Accountability, Vigilance and Resiliency to consider. These four strategies to improve and promote a positive safety culture in safety critical industries are discussed below.

A.5.1 Safety Leadership Skills Training

Leaders set the tone for the organization, by setting priorities, allocating resources and reacting to critical events. Leaders do not want employees or the public to be harmed, but they sometimes are uncertain about what actions to take to promote a positive safety culture or to maintain a focus on safety given the other demands for their attention. It is therefore important to give leaders the skills to promote a positive safety culture.

There is good evidence that safety leadership training interventions are effective.[243] An effective safety leadership development program should be multifaceted and specifically designed to meet leaders' needs. This program should include knowledge transfer (e.g., attributes of an effective safety leader), skills practice (e.g., role play exercises), coaching (individual discussion about challenges) and goal setting (e.g., target number of safety discussions).

A.5.2 Close Call Reporting System

Learning from situations that did not result in an incident but may have under the different conditions (close call), is an indicator of a positive safety culture. A strategy to promote this learning is designing and implementing a close call reporting system that is:

- Easy to use and requires minimal effort to create a report
- One where employees are confident that the report will not be used to punish themselves or others

[242] https://www.cast-safety.org/apex/f?p=102:1:18549911403111::NO::P1_X:organization

[243] Mullen, Jane & Kelloway, Kevin. (2010). Safety leadership: A longitudinal study of the effects of transformational leadership on safety outcomes. Journal of Occupational and Organizational Psychology. 82. 253 - 272. 10.1348/096317908X325313.

- Will result in review and meaningful change.

As an example of a reporting system, in the aviation industry the Aviation Safety Reporting System (ASRS) receives, processes and analyzes voluntarily submitted incident reports from pilots, air traffic controllers, dispatchers, cabin crew, maintenance technicians, and others.[244] Reports submitted to ASRS may describe both unsafe occurrences and hazardous situations. Information is gathered from these reports and disseminated to stakeholders. The reporting system is voluntary, confidential, and non-punitive and purpose is to improve the aviation system.

While this example of ASRS is at an industry-level scale, the concept and principles can be applied and customized for an individual company.

A.5.3 Safety Improvement "Beta Test"

Whether within an industry, a company, or an individual team, one way to get started with a collaborative safety improvement process is with a "Beta Test" for one safety problem. Supported by committed safety leadership, that creates an environment where there is trust in open and honest communication with assurances of no punitive actions for sharing of information:

- Select a safety problem that has been stubbornly resistant to improvement
- Create collaborative corrective action group, with representation from all who are involved in the system or subsystem
- Develop and implement cost-effective safety enhancements.
- Track implementation and continuously monitor the effectiveness of the safety mitigations.

Implementing a "Beta Test" can have a number of potential positive outcomes. Of utmost importance, an effective safety improvement that is implemented will lower risks to the public and employees. In addition, the process of implementing one collaborative safety improvement can provide an assessment of the safety culture and help an organization understand and address weaknesses in its' safety culture. Since safety issues often are a result of interdependent systems, the safety improvement process could provide learning that may be used to address other possible safety improvements in other systems or subsystems. And finally, a successful "Beta Test," where the process is collaborative and demonstrates an effective solution to improve safety, can build momentum for the organization to continue efforts to identify and solve other safety problems.

A.5.4 Time Out for Safety

Employees that promptly and openly identify safety concerns, without fear of retaliation, is an indicator of a positive safety culture.

Occupational Safety and Health Administration (OSHA) regulations give employees the right to refuse work if they feel it exposes themselves to a dangerous condition, and protects them against discrimination. In addition, gas companies also may have internal policies that encourage employees to stop work if they feel it is unsafe.

While important, these regulations and company policies are often narrowly limited to occupational or personal safety concerns, not system safety issues. Even if applied more broadly, the effectiveness of these practices can be hampered by not having a clear mechanism to stop a job.

[244] https://asrs.arc.nasa.gov/overview/summary.html

A strategy that has been successful in industries with safety critical facilities is the Time Out For Safety technique developed on BP Amoco's Andrew Platform.[245] Employees 'call a Time Out for Safety' by making a T sign with their hands, and can be accompanied by saying "Time-Out," to stop any operation if they are uncertain about anything or have safety concerns. This could, and should, include employees that have any uncertainty or concerns about system safety. Some benefits of the Time-Out for Safety include:

- The signal is a clear and simple mechanism to communicate that a concern exists, and it's meaning is readily understood. It doesn't require a high burden of proof on the person calling the Time-Out, and can be used if there is just some uncertainty. In effect, it's a Time-Out to stop and think.
- The signal can be used in noisy environments where it can be difficult to hear colleagues.
- The signal is visible and transparent to everyone present during work being performed. This makes everyone who is present accountable to support stopping the work.
- The signal is an opportunity for leaders (supervisors, managers, etc.) to demonstrate safety leadership by taking the Time-Out seriously, listening to the concerns, taking appropriate actions, and by doing so, encourage the practice.
- The signal is broadly applicable in situations within the organization where actions or decisions are being taken that could affect system safety, and is not limited to field work. For example, a Time-Out for Safety could be called during the engineering design phase of a project. A Time-Out for Safety could be called in a management meeting when a decision is being made about allocation of resources or budget.

[245] Fleming, Mark & Lardner, Ronny. (2001). Behavior modification programs establishing best practice. Offshore Technology Report 2000/048. Prepared by The Keil Centre for the UK Health and Safety Executive. ISBN 0 7176 1920 6.

Table A-2: Safety Culture Frameworks

AGA	INGAA	PHMSA	API RP 1173	CER/C-NLOPB/CNSOPB
Positive Safety Culture Indicators				
Commitment by Management A positive safety culture begins with the organization's top leaders. Management must emphasize and demonstrate that the safety of employees, customers, the public and our pipeline systems is a value that is paramount. All decisions must take into account the importance of safety. For example, production, cost, and schedule goals should be developed, communicated and implemented in a manner that demonstrates that employee, customer, public and pipeline safety is an overriding priority.	**Consistent, strategic leadership in which leaders demonstrate an uncompromised commitment to safety** Executives and managers at all levels constantly and consistently send the message that the organization is fully committed to safety in the broadest sense, for employees, customers and the public … and that accidents are both preventable and unacceptable.	**Leadership is clearly committed to safety** **Decisions demonstrate safety is prioritized over competing demands**	**Embraces safety (personnel, public, and asset) as a core value** **Assures everyone understands the organization's goals** **Allocates adequate resources to assure individuals can successfully accomplish their PSMS responsibilities**	**Committed Safety Leadership** Safety is an organizational value demonstrated by a genuine leadership commitment and expressed by providing adequate resources, systems, and rewards to serve this end.
Identify Hazards A positive safety culture expects its employees and those providing services to identify hazards and act on them. Any potential situations that could affect employee, customer, public, or pipeline safety should be promptly identified, fully evaluated and appropriately addressed. Identified hazards and near miss incidents should also be shared across the organization so that others may learn of a possible hazard.		**There is a safety conscious work environment**		**Resiliency** The capability to respond effectively to changing demands in order to manage potential or emerging risk.

AGA	INGAA	PHMSA	API RP 1173	CER/C-NLOPB/CNSOPB
Manage Risks A positive safety culture expects employees to understand the inherent risks presented by their activities serving customers and operating natural gas assets. These risks must be effectively managed through appropriate programs and management systems designed to safeguard the public as well as employees and contractors.	**The organization manages risk systematically against a framework provided by leadership** The organization has sustainable, disciplined management processes to control risk and continuously improve performance.		**Fosters systematic consideration of risk, including what can go wrong**	
Plan the Work, Work the Plan A positive safety culture encourages employees and those providing services to take the time to assess a job site and the work to identify the steps that must be performed to achieve the desired result safely, and then implements that plan in fulfilling any work activity.	**Process and results guide operational performance** Business practices consistently guided and executed according to clear definition and direction, evolved from thoughtful analysis.		**Inspires, enables, and nurtures change when necessary**	
Promote a Learning Environment A positive safety culture encourages employees and those providing services to take the time to assess a job site and the work to identify the steps that must be performed to achieve the desired result safely, and then implements that plan in fulfilling any work activity.	**Continuous organizational learning, internally and externally, from adverse and positive events** The organization shares learnings from adverse and positive events, from observations, errors, near misses, incidents, benchmarking, and activities in trade and public interest organizations and meetings. Lessons are captured and effectively shared.	**Organization practices continuous learning**	**Promotes a questioning and learning environment** **Encourages two-way conversations about learnings and commits to apply them throughout the organization**	**Vigilance** Organizational preoccupation with failure and the willingness and ability to draw the right conclusions from all available information.

AGA	INGAA	PHMSA	API RP 1173	CER/C-NLOPB/CNSOPB
Speak Up A positive safety culture also means that every individual communicates safety concerns without fear of retaliation. Open and honest communications across all levels of an organization, and to all key stakeholders, are necessary for a positive safety culture.	**A mutually trusting organization in which a culture of openness and trust engages the workforce and safety is understood as a shared responsibility** Employees trust their management to "walk the talk" and to back them on identification and resolution of safety issues; management trusts their employees and empowers them to "do the right thing."	**Open and effective communication across the organization** **Mutual trust is fostered between employees and the organization** **Organization is fair and consistent in responding to safety concerns**	**Fosters mutual trust at all levels, with open and honest communication** **Reinforces positive behaviors and why they are important** **Encourages non-punitive reporting and assures timely response to reported issues**	**Empowerment and Accountability** Accountabilities and responsibilities for safety are clearly established and documented at all levels of the organization. Ownership for safety outcomes is present at all levels and functional areas of the organization.
Personal Accountability A positive safety culture is one in which each individual takes responsibility and accountability for safety in their day to day work activities. This means individuals should focus on what more "I" can do to ensure that we, and our fellow employees, are complying with all safety standards applicable to any particular task. Working safely and keeping our pipeline systems, customers and the public safe means committing to the safety culture for ourselves, our family, our friends, our companies and our community.		**Employees feel personally responsible for safety** **Reporting systems and accountability are clearly defined**	**Encourages employee engagement and ownership**	

AGA	INGAA	PHMSA	API RP 1173	CER/C-NLOPB/CNSOPB
	Workforce investment is an ongoing management focus Processes to enhance the effectiveness of employee performance are embedded in the strategic plans of the organization.	**Training and resources are available to support safety**		
Negative Safety Culture Indicators				
			Complacency **Overconfidence**	**Complacency** Occurs when there is a widely held belief that all possible hazards are controlled and the organization has forgotten to be afraid resulting in reduced attention to risk.
			Normalization of Deviance	**Normalization of Deviance** Occurs when it becomes generally acceptable to deviate from safety systems, procedures, and processes.
				Tolerance of Inadequate Systems and Resources Occurs when it becomes acceptable to work with inadequate systems and resources, which often occurs when the organization tries to do too much with too little.
				Production Pressure Occurs when there is an imbalance between production and safety.
			Fear of Reprisal	

Appendix B Gas Company Specific Snapshot Assessments

This appendix contains individual Gas-Company Snapshots. Recognizing this Assessment records observations about the then-current state of the Gas Companies, the Panel developed Snapshots instead of a scorecard or a dashboard, which are often used by businesses to track and report on a company's strategic or tactical performance.

Each Snapshot contains a system overview, information about the field visits the Panel conducted to observe the execution of the construction and maintenance work, the Panel's observations on strengths and opportunities, and bullet points derived from a review of a company's written procedures and programs and each of the Gas Company presentations to the Panel.

Each Gas Company was provided the opportunity to review its own Snapshot prior to completion of this Final Report. A description of the Snapshot Review Process, and the comments provided by the Gas Companies in response to the Snapshots, are set forth in Appendix C.

B.1 Berkshire Gas Company - BER

B.1.1 System Overview

The Berkshire Gas Company (Berkshire) system serves about 40,000 customers in Berkshire, Franklin, and Hampshire counties in western Massachusetts. About 11% of the main and 8% of the services are leak prone materials. About 39% of the main and 18% of the services are pre-code vintage.

Table B-1: Berkshire System per 2018 PHMSA Data

	Total System Miles/Services	Leak Prone	% of System	Pre-70's vintage	% of System
Mains	760.9	82.3	10.8%	295.4	38.8%
Services	32,247	2,612[246]	8.1%	5,643	17.5%

About 20% of the meters are inside sets. And there are 16 district regulator stations, mainly serving low-pressure systems.

The systems are dependent upon Tennessee Gas Pipeline (TGP) for supply. Berkshire also owns LNG and propane air facilities, which account for about 15% of its peak day needs. They currently have a moratorium on new connections on their eastern section due to lack of supply.

Berkshire has a small presence in Massachusetts, but they are part of a much larger company.[247]

Berkshire reported having no over-pressure events in the last five years.

B.1.2 Construction and Maintenance Work (Execution)

The Panel visited 14 sites and observed construction and maintenance work including leak repairs, installation of new main as part of GSEP, a new service installation, a propane facility, and a locate and mark site. More details are provided in Appendix B.1.6.

B.1.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.1.5, the Panel observed the following, which was specifically related to Berkshire:

- Strengths:
    - Generally good relations between union and contractor crews;
    - Good use of electronic means (e.g., iPads, laptops) to access data in the field;[248]

[246] The number of copper services that Berkshire includes in its GSEP programs are not included in this number but would not have a material impact on the percentages in Table B-1.

[247] Berkshire Gas is part of AVANGRID, Inc., which is a sustainable energy company with $32 billion in assets and operations in 24 US states, owns eight electric and natural gas utilities – with an $8.3 billion rate base serving 3.1 million customers. Avangrid is owned by Iberdrola, which is a large multi-national energy company focused on renewable energy.

[248] The application is proprietary to Berkshire Gas. Even with corporate backing, proprietary software can be difficult to sustain over long periods unless there is a solid corporate commitment to maintaining the software.

- Effectively uses strong, competent contractor crews on complex jobs (Best Practice);[249]
- Utilizes inspectors (company employees) that are truly independent (checker versus doer), and are actively engaged observing work tasks and interacting with personnel;
- Requires all personnel to wear basic personal protective equipment (PPE) including hard hats, steel-toed boots, safety vests, and safety glasses and gloves on job sites, regardless of task being performed at the site;
- Held effective tailgate/job briefings on the job site before work began and complex tasks undertaken;
- Utilizes both a construction supervisor and a company inspector to monitor construction; and
- Local employees appear to have intimate knowledge of system.

- Opportunities:
  - Revisit procedures for backfill to ensure inappropriate means of compression are not being used (e.g., equipment track). See photographs in Appendix B.1.6;
  - Add more independent inspectors to improve the ratio of inspectors on job sites. The current inspector ratio of 1:8 does not provide sufficient opportunity for the inspector to provide effective oversight or guidance;
  - Inspectors should be Operator Qualified on most, if not all, tasks for broader situational awareness;
  - Consider new risks arising as a result of transitioning to a bigger company;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking;
  - Ensure crews have the right-sized backhoes and other equipment for the work being performed;
  - Address budget concerns that may be impacting the availability of resources to enhance pipeline safety;
  - Conduct an emergency preparedness drill as soon as feasible. Preferably, this is a field mock drill involving third parties and governmental agencies. Alternatively, and at minimum, conduct a mock tabletop drill. Make such drills a routine practice; and
  - Revisit corporate requirements for a competitive bid for a PE (competency should take precedence over direct cost of PE).

Berkshire's contractors performing complex jobs were very competent. In fact, one of the top three work sites visited by the Panel was run by a strong contractor crew lead, who performed a main replacement along a road adjacent to a river. See photographs in Appendix B.1.6. Good labor

[249] The Panel observed a crew that had one of the top three crew chiefs and crews the Panel observed at over 150 sites. As discussed in Section 9.1.5 and Footnote 114, the Panel received outstanding job briefings with excellent hazard identification at this location.

relations between unions and contractors made for efficient hand-off of work in the western operating area. Some challenges with certain individuals concerning labor relations may be present in the eastern operating areas.

B.1.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Berkshire system is set forth in Table B-2, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-2: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Berkshire	33.33	1.67	24.31	1.95
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Berkshire's system and renewal programs based on this leak analysis are as follows:

- Overall leak ratios are generally downward trend; the main leak ratio is comparatively high;
- Carry over backlog is dropping over time; and
- Given the age of the system, Berkshire should continue on its current renewal pace to stay ahead of overall system deterioration, unless leak ratios begin to climb.

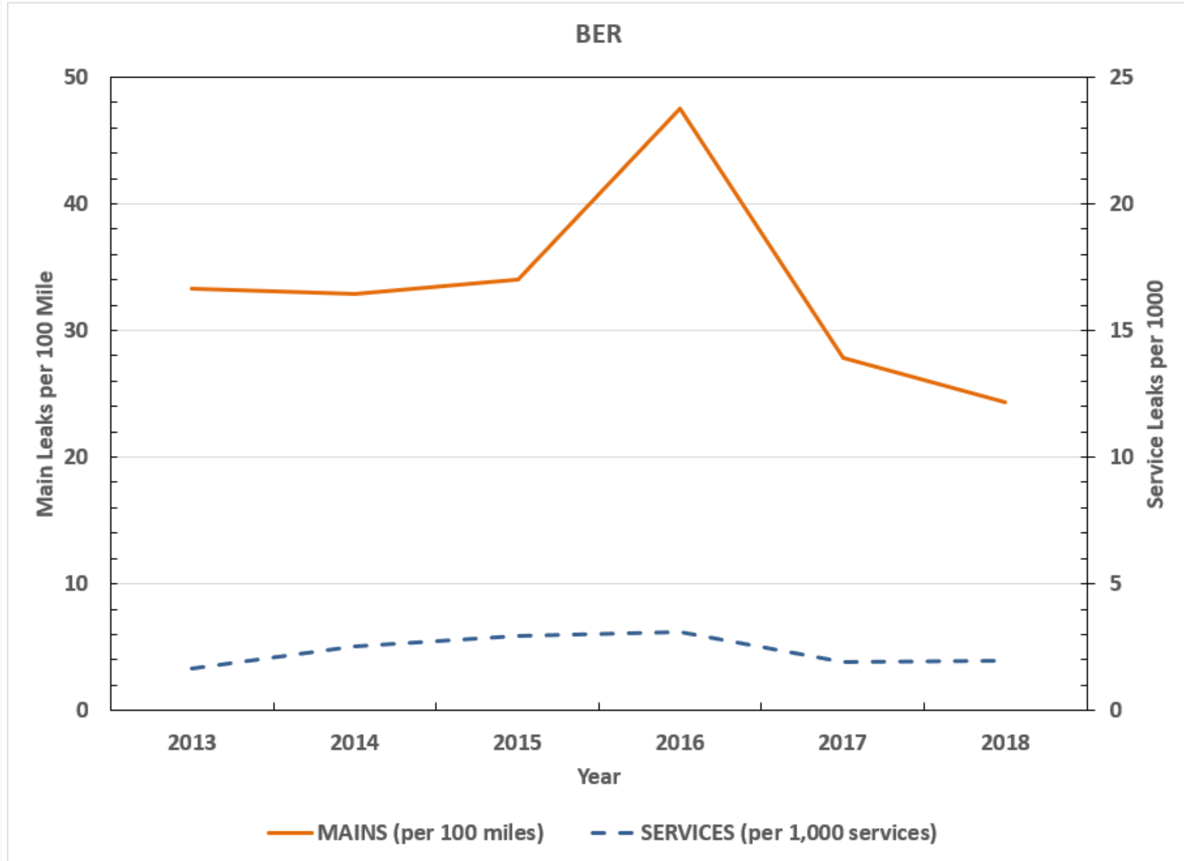


Figure B-1: Berkshire Leak Ratio (Mains and Services)

B.1.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
   a. The *O&M Manual* is relatively short with little detail and contains references to other manuals. Primarily code-focused, with no deficiencies to minimum requirements noted. Beyond code on regulator rebuild (5-year mandatory);
   b. The *O&M Manual* references *consideration* for special surveys as needed. Given the length of renewal programs, consider spelling out additional surveys, events, or both that would require special surveys;
   c. The *O&M Manual* includes a list of equipment for response trucks. It is good practice to clarify what is needed and to perform routine checks to ensure trucks are prepared to respond;
   d. Consider adding drawings/diagrams for typical maintenance work. Ensure higher risk activities are included (some drawings included for construction – see the Construction Practices topic in Item 2);

   e. Berkshire appears to have recently implemented a new system for some maintenance records. Consider a quality management program around records (maintenance and asset); and

   f. Limited information on Dig Safe practices. Consider adding clarity and process around miss locates, late tickets, conversations with excavators and metrics beyond hits per 1,000 locates. Consider a quality management program around an overall program.

2. Construction Practices:

   a. Appear to follow minimum requirements with no noted deficiencies;

   b. Tie-in work performed by internal team;

   c. Specify limited repair and construction materials – provides clarity for team;

   d. Good set of drawings/diagrams for typical installations. Review to ensure higher risk activities are included; and

   e. Did not see references to written procedures, specifically for more complex tasks. Consider when written procedures might be needed (construction and O&M activities) and develop robust, clear process to ensure safe execution.

3. Distribution Integrity Management Program:

   a. The DIMP does not appear to be actively managed and does not appear to have been revised since initial plan development in 2011;

   b. SME-centric threat identification and risk assessment. Consider a more data-driven approach;

   c. Performance measures not up-to-date in DIMP, which does not adhere to Appendix F in the DIMP plan. There is evidence in the documents that performance measures were submitted to PHMSA up to 2017. Consider a more systematic approach when reviewing and updating the plan regularly;

   d. Organizational responsibility not clearly documented; and

   e. Linkage of risk mitigation plans to specific risk results are not clearly documented.

4. Risk Management Program:

   a. Personal safety focused – starting to consider process safety;

   b. Believes GSEP could be increasing risk profile as some companies may not be prepared for that level of work;

   c. Records are a key part of a robust risk management program. Berkshire has moved towards more electronic and integrated records but this effort is in its infancy. As above, consider a quality management program around records;

   d. Consider low probability/high consequence events, and company mitigation and response.

5. Incident and Crisis Management:

   a. Lessons from Merrimack Valley – considering additional over-pressure protection on system; and

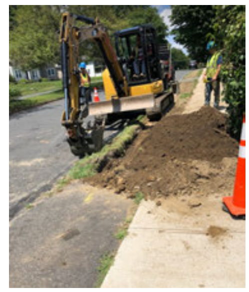
   b. No noted routine drills or exercises.

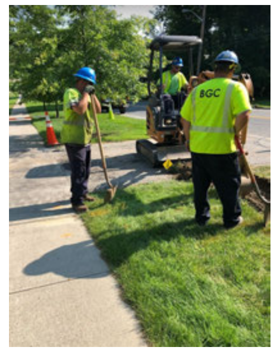
6. Management Systems:
    a. Not currently using a safety management system. Will participate in NGA process.

B.1.6 Field Visit Summary

Table B-3: Field Visit Summary

BER No.	Description	Date	Photograph
BER-1	New service installation (HP), 2 homes, part of main replacement	7/29/19	
BER-2	Main installation and services to 2 homes	7/29/19	
BER-3	Street box raising for paving project	7/29/19	
BER-4	Mark and locate, dig safe ticket	7/29/19	

BER No.	Description	Date	Photograph
BER-5	CP rectifier	7/29/19	
BER-6	Backfilling 4-in main replacement	7/29/19	
BER-7	Remote Pressure Sensing Unit	7/29/19	
BER-8	LPG Facility, Gate Station	7/29/19	
BER-9	Underground Regulator Pit/ 8-in plastic main offset	7/30/19	

BER No.	Description	Date	Photograph
BER-10	12-in CI Replacement, Gr 3 Leak	7/30/19	
BER-11	½ IP Retirement	7/30/19	
BER-12	Main and Service Installation	7/30/19	
BER-13	Greenfield Propane Air Facility	7/30/19	
BER-14	Service Center and Regulators		

B.2 Blackstone Gas Company - BLA

B.2.1 System Overview

The Blackstone Gas Company (Blackstone) gas system serves Blackstone and portions of Bellingham and Wrentham, Massachusetts. Prior to its acquisition by Liberty Utilities on October 31, 2019, Blackstone was privately owned. In the mid-1990s, the company replaced its leak prone pipe with plastic. As shown in Table B-4, there is no leak prone materials or materials pre-code vintage in the system. Blackstone has a limited amount of steel pipe near its interconnect with Tennessee Gas Pipeline. Most of the Blackstone system operates at 45 psig, with only 1 low pressure district regulator station that feeds 12 homes.

Table B-4: Blackstone System per 2018 PHMSA Data

	Total System Miles/Number	Leak Prone Miles/Number	% of Total System	Pre-70's Vintage Miles/Number	% of Total System
Mains	55	0	0	0	0
Services	1,470	0	0	0	0

Blackstone reports no over-pressure events in system over last five years.

Blackstone believes most of its risks are related to third party damage. In addition, Blackstone has identified Plexico tap tees and Handly curb valves as leak prone, resulting in an increased number of below-ground leaks on services likely attributable to these appurtenances. As a result of upgrading to more sensitive leak detection equipment, Blackstone has discovered an increasing number of above-ground leaks on meter sets.

The system is supplied by a single interconnect with Tennessee Gas Pipeline (TGP). The steel pipe downstream of the interconnection is owned by Blackstone but protected/maintained by TGP. Recognizing the risks of having a single source of gas supply, Blackstone investigated, the following backup supply options:

- CNG skid - reported that DPU was not supportive of this approach;
- Interconnect with Columbia Gas (CGM) that did not work out; and
- Interconnection with Algonquin Gas Transmission (AGT) – cost was too high ($5 million).

Blackstone has a staff of nine employees, of which five are field staff. They use consultants and outside experts as needed. They also use two construction contractors for larger projects, but report they are carefully monitored/overseen by the Senior Vice-President, Operations, who spends much of his time in the field.

B.2.2 Construction and Maintenance Work (Execution)

The Panel visited 5 field sites and observed construction and maintenance work including commercial meter set installation, new service line installation, a regulator station and the main supply interconnection with TGP. More details are provided in Appendix B.2.6.

B.2.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.2.6, the Panel the Panel observed the following,[250] which was specifically related to Blackstone:

- Strengths
  - Communication is straight forward in this small company;
  - Employees have an intimate knowledge of the system, work that has been done and local challenges/issues;
  - Prior leadership has worked on the system prior to purchasing it;
  - System is primarily modern plastic and all assets were installed in 1980 or later;
  - Maintains excellent records of installed assets;
  - Conducted a mock emergency drill with local authorities in November 2019; and
  - Used non-mechanical means for excavations.
- Opportunities
  - Organization is dependent on key personnel so should succession planning may become an issue in the future;
  - Consider improving documentation around a number of programs to improve knowledge retention and future transitions;
  - Key programs are based on third-party experts acting as subject matter experts (DIMP as an example) and appear to be prepared as a compliance activity rather than true evaluation of risk. Consider developing in-house expertise;
  - All records are manual and paper based and located at main office. Consider at a minimum backup (scan) of all records at another location. Ideally, move to electronic records/mapping over time;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking; and
  - Use PPE for all personnel at all worksites.

Blackstone benefits from its size, system composition, and the knowledge and competence of its dedicated long-standing Senior Vice-President of Operations.

B.2.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

[250] These observations were made prior to Liberty Utilities acquiring Blackstone in October 2019. The acquisition is likely to bring its own set of new benefits, challenges and opportunities.

The leak ratio of the Blackstone system is set forth in Table B-5, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-5: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Blackstone	0.0	10.84	0.0	21.77
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Blackstone's system and renewal programs based on this leak analysis are as follows:

- Blackstone reports no main leaks over the time period reviewed. This is consistent with a newer plastic system.
- Service leaks are increasing and are reported by Blackstone as all above ground meter leaks.

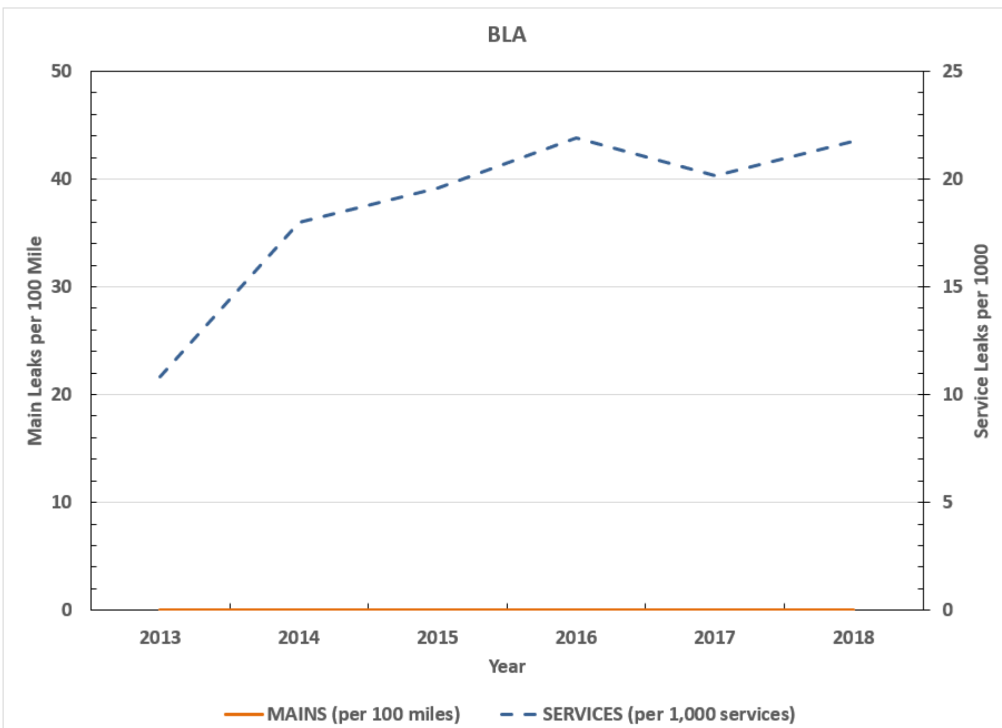


Figure B-2: Blackstone Leak Ratio (Mains and Services)

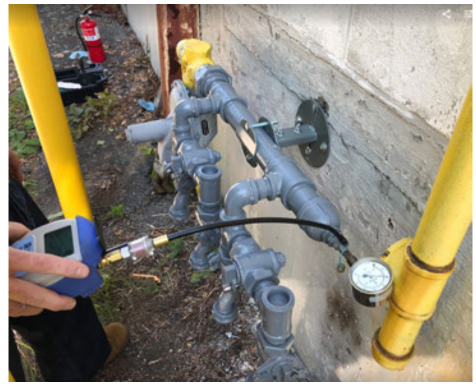
B.2.5 Program Review

1. Operations and Maintenance.
    a. The *O&M Manual* is organized with sections well marked. Primarily code focused. No deficiencies to minimum requirements noted.
    b. Consider using some diagrams/drawings for common tasks and activities. Review to ensure higher risk activities are included for clarity.
    c. See records below under risk management. Consider a quality management program around records.
    d. Consider clarifying when written procedures are required, add clarity around what is included, how to execute, etc.
    e. Consider more clarity around Dig Safe and expectations. Small community improves overall communication overall. Documentation clarifies expectation if key staff leave.
2. Construction Practices.
    a. Appear to follow minimum requirements with no noted deficiencies.
    b. As stated in O&M – consider using drawings/diagrams for typical installations. Review to ensure higher risk activities are included.
3. Distribution Integrity Management Program.
    a. DIMP does not appear to be actively managed.
    b. SME centric threat identification and risk assessment. Consider a more data driven approach.
    c. Not all documentation was included – difficult to tell how complete program is or if routinely reviewed and updated.
4. Risk Management Program.
    a. Very SME driven. Aggressive about replacing all leak prone fittings.
    b. Records are a key part of a robust risk management program. Most records are paper. Consider a quality management program for records.
5. Incident and Crisis Management.
    a. Feel they can respond to typical events on system (leaks)
    b. Do not run emergency drills. Consider routine drills – not only for routine events (leaks) but on other events – use industry happenings for ideas.
6. Management Systems.
    a. Interested in learning more and how it will impact operations

B.2.6 Field Visit Summary

Table B-6: Field Visit Summary

Location No.	Description	Date	Photograph
BLA-1	Field Office, System Overview, Planning	9/19/19	
BLA-2	Regulator Station	9/19/19	
BLA-3	Take Station	9/19/19	

Location No.	Description	Date	Photograph
BLA-4	Meter Set Replacement – Commercial	9/19/19	
BLA-5	New Service Installation	9/19/19	
BLA-6	Prior Replacement due to Hwy Project Bridge Replacement	9/19/19	

B.3 Columbia Gas of Massachusetts – CGM

B.3.1 System Overview

Columbia Gas of Massachusetts (CGM)[251] is part of NiSource (an investor-owned utility) and provides service to customers in 3 operating areas within the state (Springfield, Brockton, and Lawrence areas). As shown in Table B-7, about 13% each of the main mileage and services are characterized as leak prone pipe. Over 44% of the main and almost 16% of the services are pre-code vintage.

The system also includes 28 low-pressure service areas, which have no regulation protection at the house or EFVs on the service laterals – these low-pressure systems are protected by the over-pressure protection at the district regulator station. They have about 66,000 inside meters, the majority of which will be moved outside as part of the GSEP program.

Table B-7: Columbia System per 2018 PHMSA Data[252]

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-70's Vintage Miles/Number	% of System
Mains	4,989.5	623.3	12.5%	2,220.8	44.5%
Services	273,847	34,613	12.6%	42,571	15.6%

Natural gas is delivered to CGMs systems via two gas transmission companies: Algonquin Gas Transmission (AGT) and Tennessee Gas Pipeline (TGP). TGP is the only transmission company supplying gas to the Springfield and the Lawrence operating areas. TGP and AGT supply gas to the Brockton operating area. There are four LNG plants that are self-reported as "aging." The Panel did not assess the split on meeting peak load as between pipeline capacity and LNG plant.

CGM reported a number of over-pressure events during the time period requested. Other than the tragedy in the Merrimack Valley Region in September 2018, the majority of low-pressure system overages were minor excursions.

Many of the NiSource companies operate under the same O&M Manual. As such, certain learnings from across the organization are relevant to CGM. Columbia Gas of Ohio experienced a significant over-pressure event in Zanesville, Ohio in May 2019.[253] Columbia Gas of Massachusetts and Columbia Gas of Ohio are sister companies. In this incident, hundreds of customers were out-of-service for days, electricity was shut-off, and an emergency incident command center was set up to address the issues resulting from over-pressurization.[254] Despite the deleterious impacts of this

251 Bay State Gas Company d/b/a Columbia Gas of Massachusetts.

252 Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown, it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

253 As discussed in Fn. 16 of the *Final Report*, Columbia Gas of Massachusetts and Columbia Gas of Ohio are sister companies. They share a parent company and operate under the same *O&M Manual*. The Panel collected information about the organization's response to the Zanesville incident to better understand Columbia Gas of Massachusetts' processes concerning investigating incidents, learning from incidents, and reporting incidents to PHMSA.

254 See public reporting on the gas over-pressurization event on a distribution system in Zanesville, Ohio on a gas distribution system operated by Columbia Gas of Ohio: https://www.zanesvilletimesrecorder.com/story/news/2019/05/09/columbia-gas-shutting-off-service-south-side-zanesville/1156699001/

event, Columbia Gas of Ohio determined it was not a significant event in the eyes of the operator[255] for which a PHMSA incident report should be filed.[256]

Columbia Gas of Pennsylvania also experienced a significant event on a low-pressure system in Washington County, PA. Work was being performed on an ongoing project in the area when a home on a different street exploded. Columbia reported that a necessary pressure regulator was never added to the home during the process of upgrading from a low- to a higher-pressure system. When the pressure was raised in the newer higher pressure system, the gas filled the house and ignited. The explosion destroyed the house and five people were injured, including three firefighters and the homeowner. With the consequences meeting the necessary PHMSA threshold of damages to require a PHMSA incident report to be filed, the company did so.[257]

B.3.2 Construction and Maintenance Work (Execution)

The Panel visited 39 works sites and observed construction and maintenance work including review/remediation of abandoned service lines, leak repairs, new services, installed and ties-in of a plastic line. More details are provided in Appendix B.3.6.

1. Because of the DPU work stoppage and concerns that arose around the abandoned assets following the Merrimack Valley incident, the Panel observed 33 sites at which Columbia was inspecting and verifying the abandonment was completed and documented correctly. More details are provided in Appendix B.3.6.
2. The Panel visited 6 sites to observe construction and maintenance work including installation of new main as part of GSEP, installation of a new service line, and a response to Grade 1 leak. More details are provided in Appendix B.3.6.

B.3.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.3.6, the Panel observed the following, which was specifically related to Columbia Gas of Massachusetts:

- Strengths:
  - New training facility in 2017 to provide training for employees;
  - A number of strong effective Company and contractor crew leads;
  - The *O&M Manual* explicitly includes documenting conversations between excavators and company staff in the Dig Safe Program, which appears to be beyond the positive identification requirement from DPU when no company buried assets are present in the area; and
  - Developing a company inspector program with the intent of having company inspectors present on job sites at the ratio of 1:1.

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[255] PHMSA requires reporting of incidents within a certain time frame. An incident is defined as (1) a release of gas (and other hazardous materials) that results in (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; or (iii) Unintentional estimated gas loss of three million cubic feet or more; or (2) an emergency shutdown of an LNG facility or an underground natural gas storage facility, or (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria in (1) or (2). 49 CFR §191.3 (3).

[256] Columbia Gas of Ohio informed the Public Utility Commission of Ohio.

[257] See PHMSA Report ID: 20190095.

- Opportunities:
  - Evaluate how to become more of a learning organization, including how to utilize learnings from affiliates;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking, and not accepting accountability for an individual's role;
  - Enhance quality control of company provided inspectors, review training, and clarify expectations for Inspectors onsite;[258]
  - Improve quality control of engineering process, especially to ensure that professional engineers have all necessary information (and visit the field, as necessary);[259]
  - Conduct a root cause analysis of the Allen Street Tie In to specifically consider the:
    - Allen Street Tie-In Plan (Versions 1-7) to understand the reasons and practices for each revision, and understand the potential gaps between the records and the information relied upon by the PE;
    - Role and qualifications of the inspector;
    - Earlier line strike that occurred; and
    - Process, methods, and limits to overcome misaligned pipe ends at tie-in locations.
  - Re-visit the construction procedures related to mis-alignment of pipe to provide clear guidance on methods and limits for pipe alignment practices;
  - Enhance tracking of critical gas events, like over-pressurizations on low-pressure systems; [260]
  - Conduct more robust RCAs as means to learn from events;[261]
  - Develop and implement a plan to lower the number of over-pressure events;[262]
  - Review requirements for documentation related to traceability of steel pipe being installed (e.g., MTR and test records for all pipe being installed);

[258] At one work site, the company supplied a detailed checklist to the crew, but rather than checking off the items as each step was completed, the inspector indicated he would check off all of the items at the end of the day, thereby defeating the purpose of the checklist. In addition, he briefed the crew on a purge plan that the inspector had reason to know, via an email the night before that he acknowledged reading, was in the process of being modified by engineering.

[259] At the same work site, the purge procedure and PE-stamped drawings (Version 6) being used by the crew to start the day, were inaccurate and missing critical buried infrastructure for the purge being set up to occur that day or the next. Review of the prior versions indicated some PE-stamped drawings being corrected on the same day. This suggests the engineer stamping the drawings was not in possession of sufficient information to accurately prepare the drawing.

[260] During the Snapshot Review Process, Columbia indicated it has a tracking system of critical gas events. The Panel did not confirm the existence of the tracking system.

[261] The Panel observed opportunities to learn and communicate from incidents. See discussion in Section 9.2, and footnotes 117 and 147.

[262] As discussed in Section 9.5, the three large Gas Companies (which includes Eversource) collectively experienced just under 40 over-pressure events on their low-pressure systems and over 85 over-pressure events on their medium- and high-pressure systems (with the vast majority being slight variances above MAOP) since 2013.

- ○ Ensure check lists are being completed, step by step, at the time of the work being completed (in progress);
- ○ Improve training on ICS. Perform emergency drills regularly, including black swan events, to improve knowledge and execution;
- ○ Ensure that use of spotters for backhoes while excavating;
- ○ Ensure that guidelines are developed and/or followed regarding the requirement for Project Restart Memos, specifically designed for projects with disrupted work flow;
- ○ DIMP generally used more data, rather than the relying solely on the opinions of its SMEs, and considered external information about the potential risks to their systems; however, the organizational view of the program as, basically, a leak management program, keeps it from being grouped as one of the exceptions to treating the DIMP as a compliance requirement;[263] and
- ○ Use discovered leaks to inform selection of leak prone pipe replacements.

CGM's strength are the many dedicated, talented, committed crew chiefs the Panel encountered throughout this Assessment. In the interactions with management, however, the Panel consistently observed a concerted effort to assert that the Company's performance of the work was done right. This viewpoint contrasts with the basic tenets of becoming a learning organization in which asking questions is valued (i.e., *What do I see? How can we be better? What are we missing?*). This lack of openness to learning and looking for what may have been missed is especially striking in the aftermath of the recent incidents at Columbia.[264]

One set of field site visits epitomized the strengths and opportunities in this organization. There, the Panel observed:

- The only lesson learned by the field crews about an earlier line strike in the area was that the crew who struck the line would no longer be working for Columbia Gas;[265]
- A PE-stamped set of drawings and step-by-step procedure that failed to include 300-feet of pipe that would be involved in the purge. Also, the incorrect procedure was used to brief the crew on the work to be performed;[266]
- A company inspector who not only failed to use the checklist as intended while work progressed, but also briefed the crew using a Version 6 document that the inspector had reason to know, via an email the night before that he acknowledged reading, was in the process of being modified by engineering. When asked to explain the situation, the inspector asserted it was not his responsibility and that he was only doing what he was told;

[263] See discussion in Section 5.3.

[264] This includes the tragic incident in the Merrimack Valley, and incidents at Columbia Gas of Ohio and Columbia Gas of Pennsylvania (see Appendix B.3.1).

[265] See discussion in Section 9.2.

[266] In response to IR #8, issued by the Panel on November 7, 2019, Columbia provided the earlier versions. When reviewing the prior six versions, it became evident that – between Revision 5 and Revision 6 – all of the prior tie-in locations in this complex project were deleted. This likely provides an explanation as to how the 300 feet of pipe, that needed to be part of the purge plan, were deleted from Version 6; the same version used to brief the crew. Some revisions were made on the same day to address errors that had been inadvertently included in the immediately prior version.

- A field crew chief who identified the missing 300 feet of pipe that would be affected during the purge process refused to sign off on the plan without a revision to correct the missing assets;
- Efforts undertaken by the inspector to have engineering deliver a PE-stamped plan (Version 7) that would include the previously-missing 300 feet of pipe, while the crew prepped the site on a very busy street;
- Insistence that the complex misalignment facing the crew was just *the way it was always done* demonstrating both a determination to get the work done under the circumstances presented and a lack of critical thinking about the potential impacts of the changed circumstances presented to the crew; and
- When presented by the concerns of the Panel, an insistence by management that the work performed was safe despite the Panel's concerns about the adequacy of the investigative analysis and/or implementation of any corrective actions, and without any explanation of whether such actions were under consideration. While a calculation was provided to demonstrate that the process was acceptable, it did not consider all of the available information.

Each of these observations provide an opportunity for learning and improving the organization.

B.3.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Columbia system is set forth in Table B-8, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-8: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Columbia Gas MA	29.72	11.17	30.40	5.53
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Columbia's system and renewal programs based on this leak analysis are as follows:

- Overall leak ratio trend is downward, with a recent uptick in main ratios;
- Ratios are comparatively high;
- Causes include corrosion, joint failure, natural force damage and other – supporting continuing strong renewal programs for GSEP and pre-70's vintage assets;
- Analyze why progress in reducing leaks through GSEP appears have reversed course in 2017; and
- Monitor leak ratios and consider pipe replacement selection to ensure remediation remains ahead of general system deterioration.

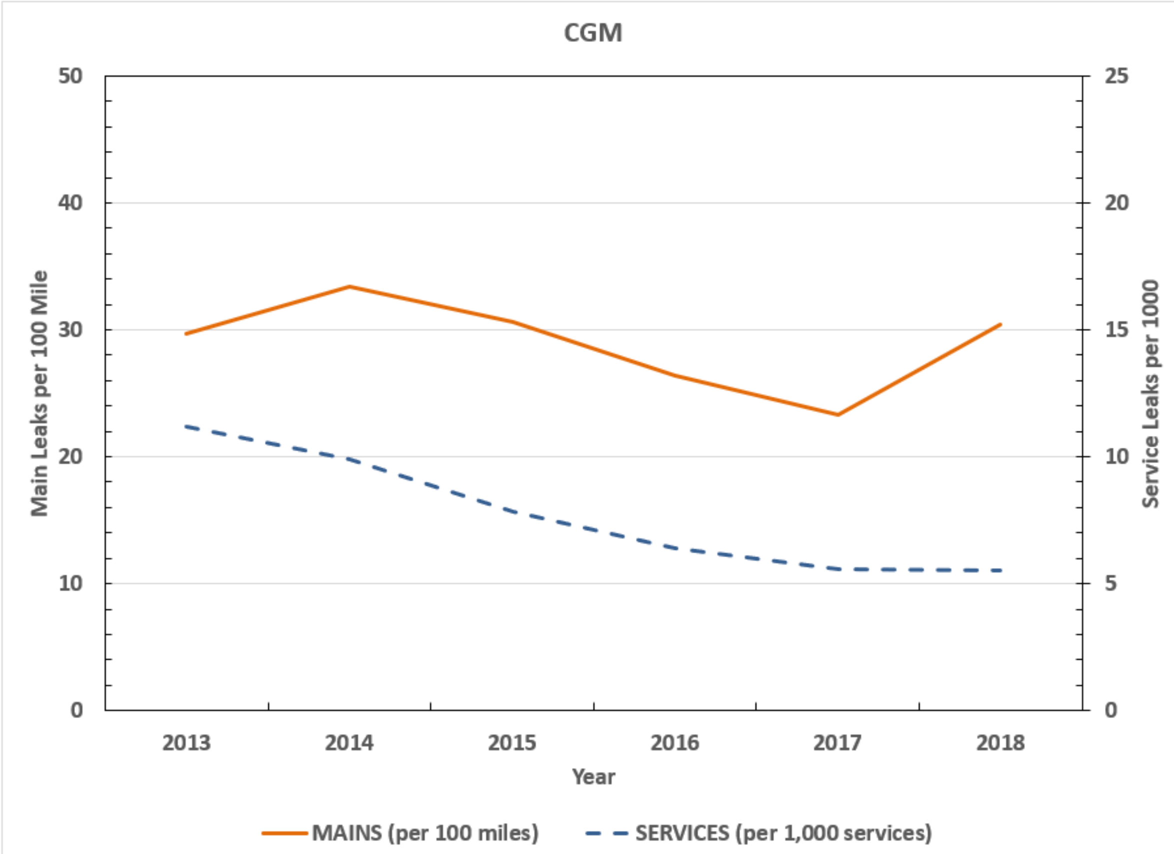


Figure B-3: Columbia Leak Ratio (Mains and Services)

B.3.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. There are a lot of drawings/diagrams of typical installations and practices, clearly identifying expectations.
    b. Responsibilities are clearly delineated in the *O&M Manual*, including which department is responsible for execution, which records to collect, etc.
    c. Not all higher risk activities have drawings/diagrams to help provide clarity and reduce risk.
    d. Procedures in the O&M manuals are generic and it is not always clear when unique, written procedures are required nor who is responsible to develop and execute.
    e. The *O&M Manual* is primarily code focused with no deficiencies noted against minimum requirements. Typical processes and procedures do not appear to incorporate company risk and integrity management priorities.
    f. While record requirements are outlined, there does not appear to be a quality management program around records.

g. The *O&M Manual* is very thorough, which makes it large and potentially overwhelming. It is available in electronic searchable format, which helps ameliorate its size.

h. The *O&M Manual* explicitly includes documenting conversations between excavators and company staff (Dig Safe Program). This is a best practice and appears to go beyond the recently adopted DPU regulation requiring gas companies to positively respond to excavators to indicate the company has no underground facilities within the safety zone.

i. Consider clarifying/setting policy for regulator station tear down as opposed to "as needed upon inspection."

2. Construction Practices:

   a. A number of typical installation drawings/diagrams are included, which is very helpful for employees and contractors. However, it is not clear when there is a unique installation who writes the procedure and how that procedure is executed.

   b. Written procedures are required for all main tie-ins.

3. Distribution Integrity Management Program.

   a. Records are key to a robust integrity management program. While record requirements are outlined in the *O&M Manual* for various maintenance and construction activities, there does not appear to be a quality management program (data quality, data management) around records;

   b. DIMP appears to be actively managed;

   c. Threat identification is more comprehensive and considers some external information;

   d. Calculated risk assessment at the segment level;

   e. Risk model includes pipes and regulator stations;

   f. Program is reviewed annually, which exceeds minimum requirements; and

   g. Link between risk mitigation plans and specific risk results for lower threshold risks could be more clearly defined.

4. Risk Management Program:

   a. The CGM management team believes GSEP is moving at an appropriate pace, with about 80% of the work planned to be complete within 15 years. The Panel questions if the right pipe is being replaced given the increasing leak ratios discussed in Appendix B.3.5;

   b. The LNG plant is aging and adds operational and reliability risk to the system;

   c. The current SCADA system provides monitoring with limited control capability in portions of the system; and

   d. The CGM management team did not appear to think about risk in a holistic manner, nor did it appear to consider company and community risk tolerance it integrates into overall processes and systems.

5. Incident and Crisis Management:

   a. Emergency plan generally written for compliance;

   b. Limited emergency exercises. No full-scale exercises noted;

c. Just starting to learn about root cause analysis – how to, follow up, etc.; and

d. Includes provision requiring investigation of each PHMSA reportable and with development of lessons learned. This appears to be a limited process that could be enhanced with a review of effectiveness of changes implemented to address lessons learned. As noted in Appendix B.3.1, the determination of concerning what constitutes a "significant event" in the eyes of the operator does not include items the Panel (and likely the public) would consider significant. CGM may wish to recalibrate reporting activity to be more forthcoming.

6. Management Systems:

a. Some experience with SMS in VA (corporate);

b. Some learning outside industry in process (Westinghouse Nuclear); and

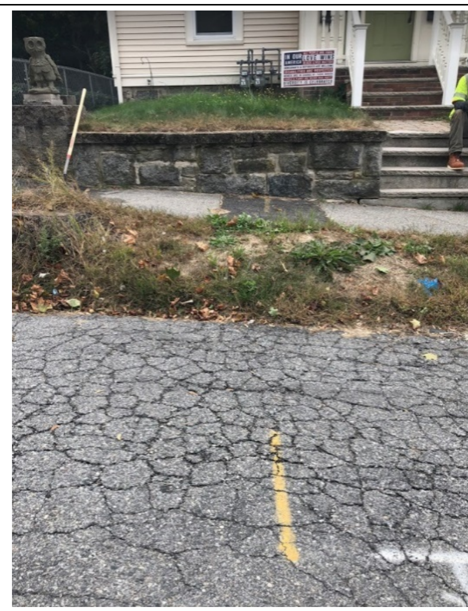
c. Infancy stages.

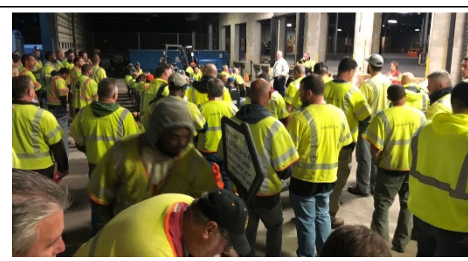
B.3.6 Field Visit Summary

Table B-9: Field Visit Summary

Location No.	Description	Date	Photograph
CGM-1	Assessment of Abandoned Service	9/19/19	
CGM-2	Assessment of Abandoned Service	9/19/19	
CGM-3		9/19/19	No photograph, cancelled

Location No.	Description	Date	Photograph
CGM-4	Assessment of Abandoned Service	9/19/19	
CGM-5	Assessment of Abandoned Service	9/19/19	
CGM-6	District Regulator Station	9/19/19	

Location No.	Description	Date	Photograph
CGM-7	Assessment of Abandoned Service	10/7/19	
CGM-8	Assessment of Abandoned Service	10/7/19	
CGM-9	Assessment of Abandoned Service	10/7/19	No photograph

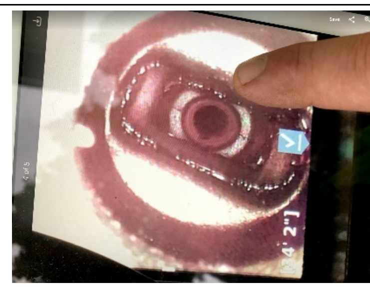
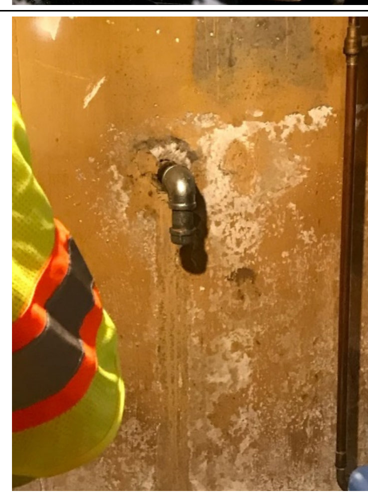
Location No.	Description	Date	Photograph
CGM-10	Assessment of Abandoned Service	10/7/19	
CGM-11	Assessment of Abandoned Service	10/7/19	
CGM-12	Morning Tailgate, Assessment of Abandoned Service	10/7/19	

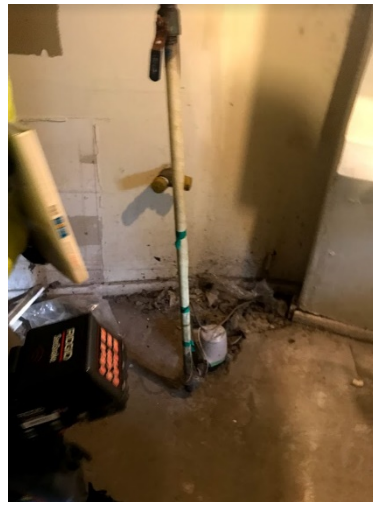
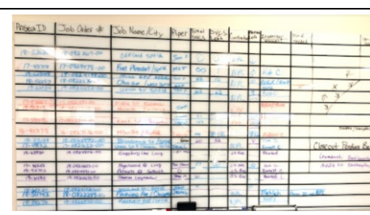
Location No.	Description	Date	Photograph
CGM-13	Assessment of Abandoned Service	10/7/19	
CGM-14	Assessment of Abandoned Service	10/7/19	
CGM-15	Assessment of Abandoned Service	10/7/19	

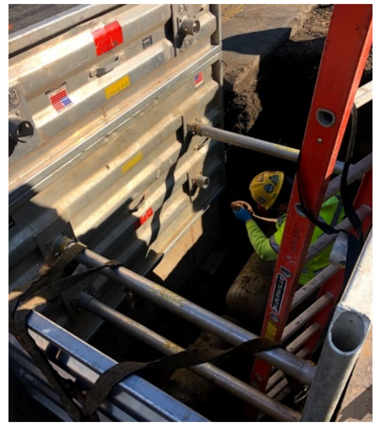
Location No.	Description	Date	Photograph
CGM-16	Assessment of Abandoned Service	10/7/19	
CGM-17	Assessment of Abandoned Service	10/7/19	
CGM-18	Assessment of Abandoned Service	10/7/19	

Location No.	Description	Date	Photograph
CGM-19	Assessment of Abandoned Service	10/7/19	
CGM-20	Assessment of Abandoned Service	10/10/19	
CGM-21	Assessment of Abandoned Service	10/10/19	

Location No.	Description	Date	Photograph
CGM-22	Assessment of Abandoned Service	10/10/19	
CGM-23	Assessment of Abandoned Service	10/10/19	
CGM-24	Assessment of Abandoned Service	10/10/19	
CGM-25	Assessment of Abandoned Service		No photograph

Location No.	Description	Date	Photograph
CGM-26	Assessment of Abandoned Service	10/10/19	
CGM-27	Assessment of Abandoned Service	10/10/19	
CGM-28	Assessment of Abandoned Service	10/10/19	
CGM-29	Assessment of Abandoned Service	10/11/19	

Location No.	Description	Date	Photograph
CGM-30	Assessment of Abandoned Service	10/11/19	
CGM-31	Assessment of Abandoned Service	10/11/19	
CGM-32	Assessment of Abandoned Service	10/11/19	
CGM-33	Assessment of Abandoned Service	10/11/19	No photograph. Job was finished
CGM-34	Springfield Operations Center	11/6/19	

Location No.	Description	Date	Photograph
CGM-35	Allen Street Tie-In – East end	11/6/19	
CGM-36	Service install	11/6/19	
CGM-37	Service install	11/6/19	

Location No.	Description	Date	Photograph
CGM-38	Allen Street Tie-in - West End	11/7/19	
CGM-39	Gr 1 Leak, where prior sewer work was evident	11/7/19	

B.4 Eversource Energy - EVE

B.4.1 System Overview

Eversource Energy[267] (Eversource) serves over 50 towns in Central, Eastern, and Southeastern Massachusetts and is part of a larger Investor-owned utility with operations in other Northeast States. As shown in Table B-10, 29% of mains and 14% of services are leak prone pipe. Over 90% of leaks on mains come from the 29% of main that is leak prone material. About 35% of the mains and 21% of the services are pre-code vintage.

The system also contains about 1,000 miles of Aldyl-A, of which about 300 miles is pre-1984 resin, a known problematic pipe.

Table B-10: Eversource System per 2018 PHMSA Data

	Total System Miles/Services	Leak Prone Miles/Services	% of System	Pre-70's Miles/Services	% of System
Mains	3,292	955	29%	1,149	34.9%
Services	204,947	28,492	14%	42,402	20.7%

There are about 58,300 inside meters, from low pressure to 60 psig. There are also 114 district regulator stations in Massachusetts that feed and protect low-pressure systems.

Eversource reported 14 over-pressure events on low-pressure systems during the time period under review. They state that improved processes and SCADA have likely increased the frequency of identifying over-pressure events. They did not provide any details on the events for review.

The various systems are fed from Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) as well as two LNG plants. The LNG plants cover about 42% of the peak day load.

B.4.2 Construction and Maintenance Work (Execution)

The Panel visited 16 sites and observed construction and maintenance work including service install, main install, leak repairs, and regulatory pit install. More details are provided in Appendix B.4.6.

B.4.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.4.6, the Panel observed the following, which was specifically related to Eversource:

- Strengths:
    - Leadership team appeared to be strong and focused on safety – employee, public and system – and welcoming input and embracing the opportunity to learn;
    - Use of vacuum truck to excavate in areas with complex buried infrastructure (Best Practice);
    - Use of classification of worker skill set based on experience (A, B, C, D) with crews mixed with experience levels (Best Practice);

[267] NSTAR Gas Company d/b/a Eversource Energy.

- Good communication between field crews and field supervisors;
- Requires all personnel wear basic personal protective equipment (PPE) including hard hats, steel-toed boots, safety vests, safety glasses, and gloves when on a job site, regardless of task being performed at the site;
- Using hourly wages instead of a price per foot or unit price for highly complex replacement jobs;[268]
- Assigning strong, competent contractor construction crews to the more complex jobs (Best Practice);[269]
- Holding effective tailgate/job briefings on complex job sites before work begins and complex tasks are undertaken (Best Practice);[270]
- Crews carry a card using a QR code to display tasks for which individual is Operator Qualified to perform (Best Practice);
- Taking the time for a re-mark when marks were not clear;
- Use of a “clear” flag to show someone has been there to locate and mark (Best Practice) (See Figure B-6);
- Using electronic means (e.g., iPads or tablets) to display and collect data in the field;
- Positioning truck and heavy equipment at job sites to maximize protection of workers from traffic;
- Company uses safety stand-downs. This was observed after the line strike and at the work site where safety concerns were raised;
- Going beyond compliance with more robust DIMPs, appears to utilize their DIMPs as a vehicle for developing a better understanding and mitigating risks associated with its gas systems;[271]
- Industry leading emergency response program:
  - Clearly defined roles and responsibilities (Best Practice);
  - Routinely practice emergency drills (Best Practice);

[268] As discussed in Section 8.2.3, the Panel observed an Eversource job in which the contractor at a job near MIT excavated less than 20 to 30 feet per day in a complex area of buried infrastructure (e.g., steam line) using a vacuum truck.

[269] One crew observed by the Panel was one of the top three crew chiefs and crews the Panel observed in the over 150 sites.

[270] As discussed in Section 9.1.5, Footnote 119, the Panel received outstanding job briefings with excellent hazard identification at this location.

[271] As discussed in Section 5.3, the DIMPs that go beyond compliance demonstrate continued learning and evolution of the program. Among other characteristics, a more mature DIMP increasingly relies more on data, becoming less reliant on the opinions of its SMEs, demonstrates a strong link between the plan and decision making on which projects to undertake, has a clear organizational responsibility for the plans, with a clear connection to how the DIMPs interact with the company’s risk management approach. By its very nature, opportunities to continue to improve the DIMP exist.

    - Assign emergency response roles when hiring personnel and conducting emergency response training as part of on-boarding new employees; and
    - Using vests with roles printed on the back for personnel to wear when entering the Incident Command Center, making it easier for everyone in the room to know who is performing which role. (Best Practice).
  - Conducting a live action mock emergency drill in October 2019 that included regulatory agencies and outside entities;
  - Use of "Underground leak classification criteria" card by crews for consistent grading of leaks. See photograph in Appendix B.4.7. (Best Practice);
  - Strong competent Gas Control with approach that appropriately considers the nuances between the systems in Connecticut and Massachusetts that require the system to be operated completely separately;
  - Leak ratio trend shows they are replacing the right pipe at the right pace. (Best Practice);[272]
  - Already began shift to process safety/hazard identification; and
  - Already working on SMS – self reported level 2 on API scale.
- Opportunities:
  - Review and improve excavation practices;
  - Improve pipe fitter scheduling;
  - Add independent, engaged inspectors to achieve a ratio closer to 1:1 or 1:2 inspectors per job site;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking;
  - Increase the pace of replacing leak prone pipe to reduce risk, provided it can be done safely;
  - Track critical gas events, like over-pressurizations on low pressure systems, and conduct root cause analysis as means to learn from events;[273]
  - Develop and implement a plan to lower the number of over-pressure events;[274]
  - Better assess work position of equipment during excavations to protect against potential pipe damage (e.g., dig site setup); and
  - Evaluate barriers to moving more meters outside.[275]

[272] As noted in Section 8.2.3.2, Eversource stands out for the drop in discovered leaks between 2013-2018. Although the pace of replacement is behind other Gas Companies, the results of the leak ratio analysis indicate Eversource has prioritized replacing the right pipe to achieve such a significant reduction in its leak rates.

[273] As noted in Section 9.5, Eversource did not provide the Panel with information about the circumstances or cause of its over-pressure events. In the Snapshot Review Process, Eversource reports it did not believe the response to the IR called for information about the circumstances, and subsequently provided the information to the Panel. Moreover, as noted in Section 3.2.2, Eversource also declined to provide the Panel with over-pressurization information sought from affiliated companies operating outside of Massachusetts and under an O&M similar to the one used by Eversource in Massachusetts.

[274] As discussed in Section 9.5, the three large Gas Companies (which includes Eversource) collectively experienced just under 40 over-pressure events on their low-pressure systems and over 85 over-pressure events on their medium- and high-pressure systems (with the vast majority being slight variances above MAOP) since 2013.

[275] Eversource's procedure requires meters to be moved outside as part of its replacement programs. It also allows an exception to this rule, with director approval. Nonetheless, the Panel observed meters left inside in circumstances where it appeared like a move outside was feasible.

Eversource is a large company with a complex system. It benefits from strong leadership that appears open to learning, the presence of technical expertise, corporate planning and availability of resources. They appear to have many improvements underway but have more work to do to bring their good ideas to full fruition. The downward trend of the leak ratio indicates this Gas Company replaced the right pipe to reduce leaks. But, as noted below, Eversource does not appear to be on pace to meet the 20-year replacement goal.

Preparedness for emergency response was clearly at the front of mind for the company and resulted in what appears to be an industry-leading program.

The Panel also observed Eversource overcame the barriers to executing construction projects more readily than other larger gas companies.

The Panel observed several immediate safety hazards at two work sites which it asked Eversource to take to the DPU as part of the Panel's obligation under the Guidelines for Engagement. These included:

- A line strike – likely violation of use of mechanical means near live gas service; more importantly, missed opportunities to learn from line strike;
- Use of mechanical means to dig near line – with backhoe teeth marks next to pipe; and
- Ineffective crew chief – who did not hold a job brief. Then, when asked by the company escort on behalf of the Panel to hold one, attempted to gather the crew (who were unresponsive to his orders) to stop work for the briefing, and then hastily held one that presented no meaningful content.

Eversource called the DPU to report these observations and agreed to provide corrective actions within 30 days.[276] Gas Company leadership also called the Panel as part of a learning opportunity to discuss the observations.

As shown in Table 8 in Section 8.2.3.1 (see Table B-11 for relevant excerpt), if the pace of renewal in the future remains roughly the same as averaged over the past five years, it does not appear Eversource is on the pace to meet the 20-year timeframe for replacement of mains envisioned under GSEP.[277] This observation is based on five years, or 25% of the 20-year plan, elapsing without 25% of the work having been completed. At the current pace, the projected year of main replacement completion is 2045.

Table B-11: Excerpt from Table 8 (Based on 2013-2018 Pace)

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Service Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (Based upon Current Pace)
EVE	2652	16% reduction 1,133 to 955 (178)	27% reduction 39,077 to 28,492 (10,585)	2045

276 During the Snapshot Review Process, Eversource indicated that the DPU Division of Pipeline Safety advised them to fill out the usual paperwork used to report a line strike, which they did.

277 Like several other Gas Companies, Eversource indicated during the Snapshot Review Process that the pace of replacement over the last five years is not reflective of the future planned pace. Eversource reports it has been increasing the pace each year as trains and qualifies its workforce to enable it to safely increase the pace. Eversource has a plan to increase the pace in future years. They report they are currently on pace to meet the 20-year goal originally set under GSEP.

B.4.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Eversource system is set forth in Table B-12, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-12: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Eversource	47.18	4.59	22.33	2.24
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Eversource's system and renewal programs based on this leak analysis are as follows:

- Leak ratio for mains and services on downtrend trend, with the main leak ratio sharply lower;
- Causes are corrosion, natural force and other, which is consistent with the types of materials in the system; and
- Pace of renewal is staying ahead of overall system deterioration.

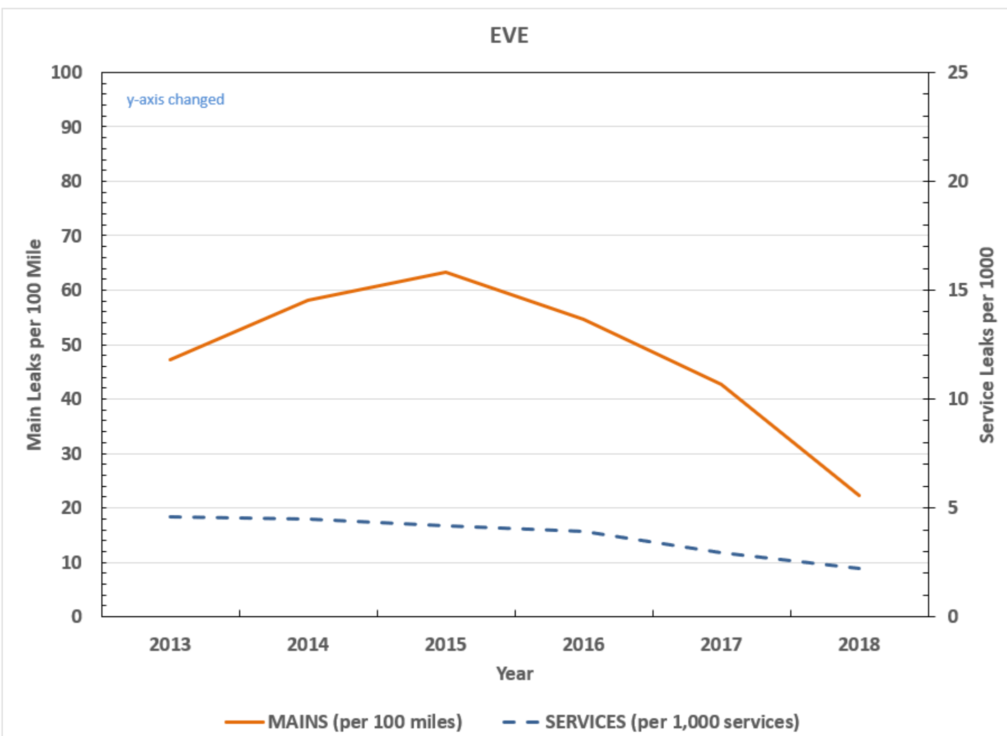


Figure B-4: Eversource Leak Ratio (Mains and Services)

B.4.5 Review of Written procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

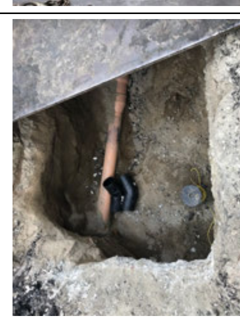
1. Operations and Maintenance:
    a. The *O&M Manual* is code focused with some additional information such as references to additional inspections and information if they have a higher risk line. No noted deficiencies to minimum requirements;
    b. The *O&M Manual* is large and well organized with a number of drawings/diagrams. Consider review of higher risk activities – do you have the right visuals for clarity for those activities?
    c. Record requirements in the *O&M Manual*. Did not see a quality management program around records;
    d. References to written procedures in some areas but did not see any specifics on when required, roles and responsibility, what does good look like, who executes (and how), etc.; and
    e. Consider clarifying procedures around late tickets, miss locates, rescheduling locates, etc. Also clarify documentation requirements.

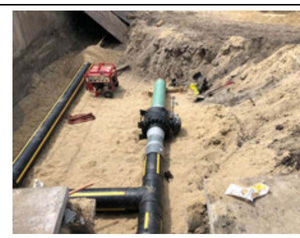
2. Construction Practices:
    a. Drawings/diagrams for typical installations included. Review to ensure all key and higher risk practices are included;
    b. Procedures in the *O&M Manual* are generally good and robust. Clarify when written procedures are required as well as who, how, etc.; and
    c. No noted deficiencies to minimum requirements.
3. Distribution Integrity Management Program:
    a. Good asset and integrity management plans rely on good records. Team recognized legacy records have gaps and are working to solve. (Eversource has been on GIS for about 20 years and has worked to keep those records clean and robust);
    b. DIMP appears to be actively managed;
    c. Threat identification is more comprehensive and considers some external sources;
    d. More detailed system knowledge;
    e. Risk assessments are more data driven, with some SME input;
    f. Risk results by asset type and town at a segment level within that location, but not risk prioritized at a segment level across the system (which would help with risk-prioritization across the entire system);
    g. Linkage of risk mitigation plans to specific risk results not documented; and
    h. While the reduction in leak rates demonstrated by Eversource is clearly evident, there are opportunities vis-a-vis more sophisticated analytics and predictive capabilities. The DIMP currently used appears to be based on the Northeast Gas Association DIMP template.

4. Risk Management Program:
    a. Appears to be considering risk more holistically;
    b. Understands records are a risk and working to improve;
    c. Understands that supply uncertainty adds risk – operationally as well as reliability;
    d. Considers unknown unknowns; and
    e. Believes GSEP is moving at appropriate pace and is providing planning stability (for the company as well as local communities and contractors).
5. Incident and Crisis Management:
    a. Employees have assigned roles in emergency plan;
    b. Continuing to evolve incident command, train employees, etc.;
    c. Perform annual emergency drills;
    d. Had 44 lessons learned from Merrimack Valley and are working to implement; and
    e. Recognizes communication (internally and externally) during an incident needs additional effort.
6. Management Systems:
    a. Interested in learning more;
    b. Self-assessment is level 2 on API scale; and
    c. Evaluating higher risk activities and teams working to identify potential hazards.

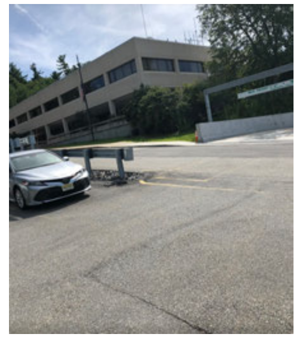
B.4.6 Field Visit Summary

Table B-13: Field Visit Summary

Location No.	Description	Date	Photograph
EVE-1	Main Relay	8/3/19	
EVE-2	Main Relay	8/3/19	

Location No.	Description	Date	Photograph
EVE-3	Service retirement	8/3/19	
EVE-4	Regulator Pit Installation	8/3/19	
EVE-5	Regulator Pit and tie over	8/3/19	
EVE-6	Service Installation	8/5/19	
EVE-7	Service Installation	8/5/19	

Location No.	Description	Date	Photograph
EVE-8	Main Extension – Builder install	8/5/19	
EVE-9	Service Install – New construction	8/5/19	
EVE-10	Service Install – new construction	8/5/19	
EVE-11	Service Cut off	8/5/19	

Location No.	Description	Date	Photograph
EVE-12	Southborough Service Center	8/5/19	
EVE-13	Service relay	8/6/19	
EVE-14	New service	8/6/19	
EVE-15	Main cut/cap, new service to IP	8/6/19	

Location No.	Description	Date	Photograph
EVE-16	New Construction	8/6/19	

B.4.7 Other Photographs

Leak Grading Card

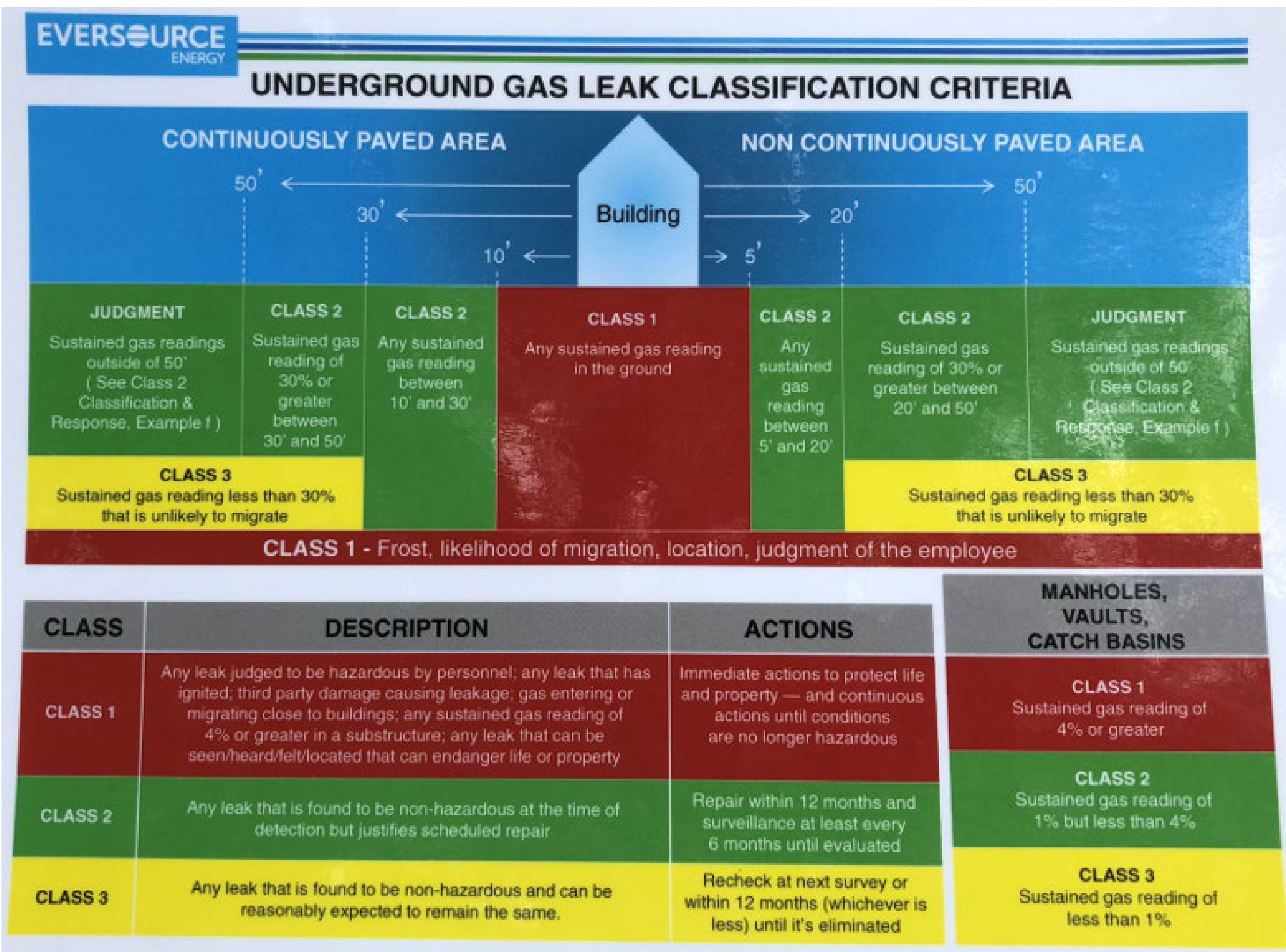


Figure B-5: Leak Grading Card

Figure B-6: Clear Flag

B.5 Holyoke Gas & Electric - HOL

B.5.1 System Overview

Holyoke Gas & Electric (Holyoke) serves customers in Holyoke and Southampton, Massachusetts. As shown in Table B-14, about 28% of the mains operate at low pressure, and 13% of its services are leak prone. About 41% of the system that was installed pre-1970.

Table B-14: Holyoke System per 2018 PHMSA Data[278]

	Total System Miles/Number	Leak Prone Miles/Number	% of Total System	Pre-1970s Miles/Number	% of Total System
Mains	185	52	28%	75	41%
Services	8,477	1,065	13%	1,522	19%

At the time of the field visit in mid-2019, Holyoke indicated 52 miles of cast iron remain with 80 miles of low-pressure pipe. Holyoke plans on keeping low-pressure plastic pipe in the system. They understand that low pressure can create additional over-pressure risks at the station. Holyoke also reported it has begun a more aggressive (10 year) service renewal program.

There are 18 district regulator stations, 12 of which serve the low-pressure system. The low-pressure system appears to be integrated, meaning that one station can be removed from service for maintenance without taking a section of the system out of service.

Holyoke provides in home appliance service to customers and uses that opportunity to also inspect and check out customer piping, check for inside leaks, etc.

Holyoke reports no over-pressurization events on its low-pressure system in the last five years. The last unplanned event of blowing gas was 3-4 years ago when non-restraining coupling blew off during hand-digging work at a location on Pearson Road.

The system is supplied by an interconnect with Tennessee Gas Pipeline (TGP), two interconnections with Columbia Gas, an interconnection with Westfield Gas & Electric,[279] and an LNG plant located near the TGP interconnect. There are also two emergency interconnects with Columbia Gas, located on another part of the system. One interconnect allows gas to flow both directions and one interconnect is from Columbia to Holyoke only. The LNG plant provides 40% of the peak day supply.

Holyoke has very little staff turnover. In the Fall of 2018, the Gas Superintendent left suddenly due to health reasons, highlighting the need for processes to pass on institutional knowledge to others. Subsequently, a new Gas Supervisor was appointed.

B.5.2 Construction and Maintenance Work Execution

The Panel visited 8 field sites and observed activities related to activities related to construction and maintenance work. More details are provided in Appendix B.5.6.

[278] Mains or services that were reported as “unknown” vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

[279] In the event of a force majeure, the reliability of supply to Holyoke from the interconnections with Columbia Gas and Westfield would depend upon those Gas Companies first having sufficient supply to meet its own customer demands and second, providing additional supply to Holyoke. See generally, Section 8.4.2.

B.5.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.5.6, the Panel observed the following, which was specifically related to Holyoke:

- Strengths:
    - Well-run organization with strong field execution practices;
    - Being a learning organization, interested in feedback on what is working and what could use improvement;
    - Frequent communication throughout the day between leadership, engineers, gas employees, and contractor crews in the field Benefits from smaller sized organization. (Best Practice);
    - Focus on opportunities to improve and learn from others (e.g., discussion at morning meeting about another company's failure; see something say something and don't see something expected, say something) (Best Practice);
    - Cadet program identifies and trains new employees early. Adopting this innovative approach to address workforce availability and knowledge transfer concerns entails identifying high school graduates to work in the Gas Company with paid internships during college years, and a paid job available at the end of college should the applicant wish to be hired. (Best Practice);
    - Crew chief keeps a notebook with drawings of each job; completes them at the end of the work before leaving job site; copies the page and gives it to office personnel to update the records. These notebook drawings appear to be very thorough. (Best Practice);
    - Generally good job briefs with thoughtful identification of site-specific hazards;
    - Using company employees as truly independent (checker versus doer) and actively engaged, and a knowledgeable inspector observing work tasks and interacting with personnel on a 1:1 ratio (Best Practice);
    - Required all Company personnel to wear basic personal protective equipment (PPE) including hard hats, steel-toed boots, safety vests, safety glasses and gloves when on a job site, regardless of task being performed at the site;
    - Positioning trucks and heavy equipment, including the backhoe, to protect workers from traffic (Best Practice);
    - Conducting a tabletop mock emergency drill with local officials in September 2019;
    - Excellent records of installed (legacy) assets (Best Practice); and
    - Using a brass hammer to reduce possibility of sparks in excavation(Best Practice).
- Opportunities:
    - Consider increasing the pace of replacing leak prone pipe, provided it can be done safely (see analysis below);
    - Develop more robust documentation for key processes and information to improve system knowledge and records. This helps manage knowledge transfer in key

positions/losing key information and it also ensures consistency for said key processes and information;

- Consider moving company inspectors between contractor crews to provide a better balance between benefits of being familiar with individual crew and continued need for vigilance;
- Ensure everyone on worksite is wearing appropriate PPE (including steel toed boots) and consider implementing consistent requirements for PPE between company and contractors;
- Provide tap records to crews regardless of whether performing "dirt work" or not;
- Continue to watch for paving over curb valves; and
- Continue to monitor overall progress using a leak ratio analysis and generally increase renewal if needed to stay ahead of system deterioration. In particular, while the overall leak ratio trend is currently down:
  - The high percentage of cast iron and the high leak ratio suggests system risk would benefit from a more aggressive cast iron main renewal program; and
  - The cause of leaks on services, the material inventory, and the service leak ratio, suggests a more aggressive service renewal program, such as the 10-year program Holyoke has referenced, would reduce system risk more quickly.

Holyoke benefits from its size, cohesive workforce, good communications and being a learning organization. It is a well-run organization with strong field execution practices and strong leadership.

While Holyoke is not covered by GSEP, if the pace of replacement in the future remains roughly the same pace as the last five years, [280] Holyoke would not complete its replacement of leak prone pipe until 2070.[281] For those companies with less than 100 miles of leak prone pipe remaining, including Holyoke, replacement of leak prone pipe within a much shorter time (e.g., five years) would appear feasible.[282]

The current pace of replacement is shown in Table 8 in Section 8.2.3.1 (see Table B-15 for relevant excerpt).

[280] Like several other Gas Companies, Holyoke indicated during the Snapshot Review Process that the pace of the last five years is not reflective of the future planned pace. Holyoke reports it has been focused on replacing bare steel pipe first and will shortly be shifting resources to replacing other leak-prone pipe such as cast iron. Under its current plans, Holyoke reports leak prone pipe replacement is planned to be completed by 2048.

[281] During the field visit, Holyoke management indicated it had decided to move to a 10-year replacement program after discussions with the Panel in early 2019.

[282] This assumes appropriate support from all Stakeholders to reduce risk and availability of appropriately trained resources to execute the work safely. During the Snapshot Review Process, Holyoke indicated it would face significant challenges to increase the pace to replace the existing leak-prone pipe within the next five years. This would require nearly a doubling of their existing gas distribution and engineering workforce, retaining qualified contractor labor, and obtaining necessary police detail.

Table B-15: Excerpt from Table 8 (Based on 2013-2018 Pace)

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Services Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (Based upon Current Pace)
HOL	7330	9% reduction 57 to 52 (5)	54% reduction 2,302 to 1,065 (1,237)	2070

B.5.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year. The leak ratio of the Holyoke system is set forth in Table B-16, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-16: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Holyoke	40.76	6.43	31.35	4.60
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Holyoke's system and renewal programs based on this leak analysis are as follows:

- The overall trend for main and services leaks is downward (see Figure B-7).
- The leak ratio numbers are relatively high compared to modern plastic and steel systems.
- The cause of the leaks on services are reported as corrosion and other – mechanical couplings. Both of these risks are time dependent and therefore will likely increase over time.

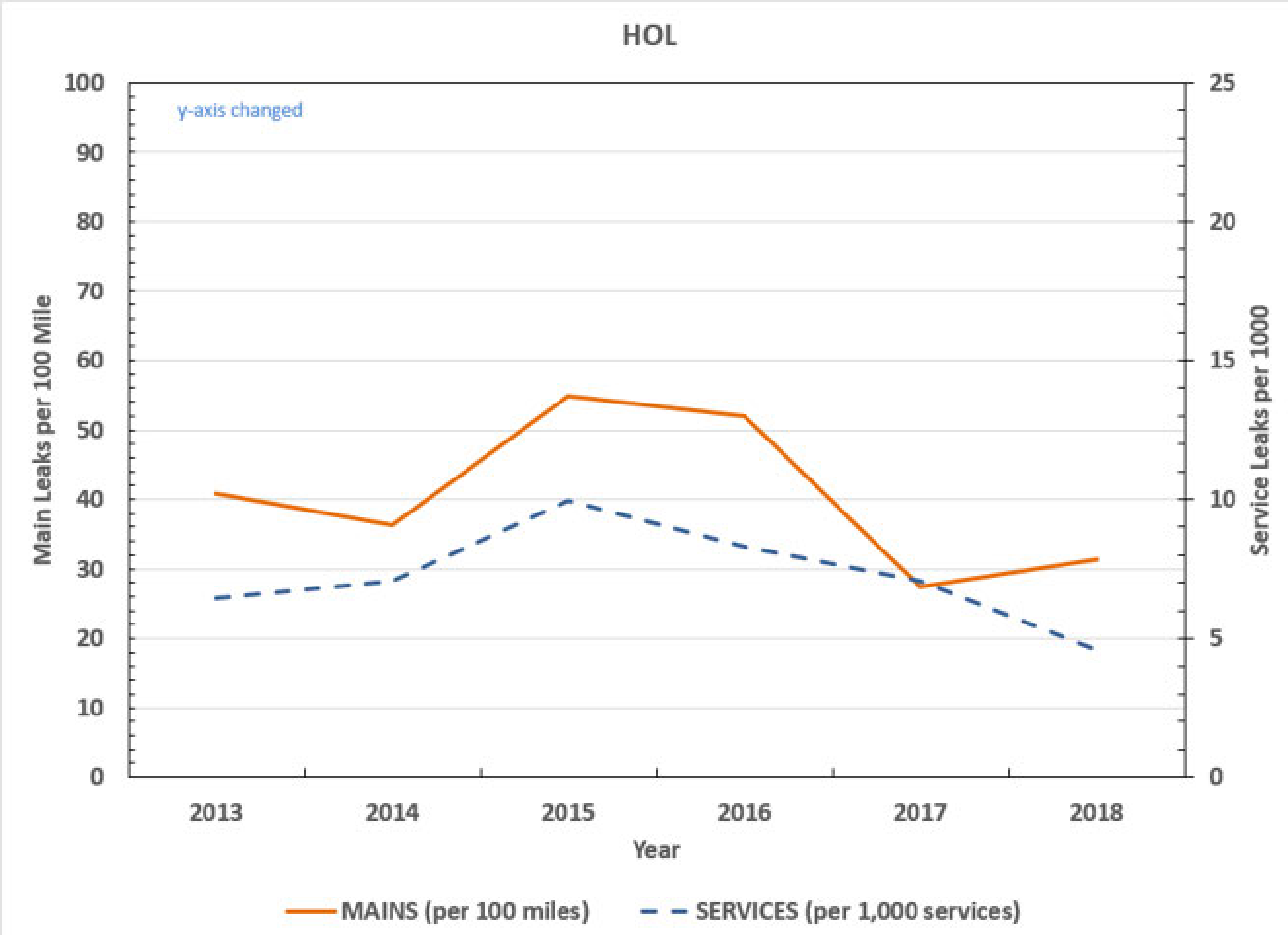


Figure B-7: Holyoke Leak Ratio (Mains and Services)

B.5.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. The *O&M Manual* is organized and easy to use, written in a less formal, regulatory way than the other O&M manuals. Primarily code focused, with no deficiencies to minimum requirements noted;
    b. The *O&M Manual* does not include diagrams/drawings for common tasks and activities. Consider adding for clarity for team;
    c. Written procedures are mentioned in the Uprating section of the *O&M Manual*, but no details provided. Consider developing a more robust policy around written procedures – when required, responsible parties, how to execute, etc. Seek out best practices from trade associations or other SMEs;

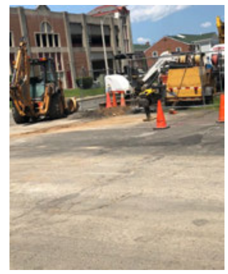
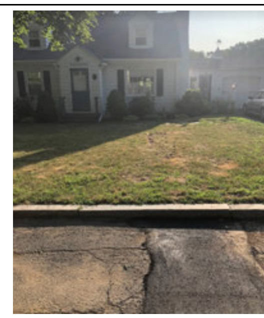
   d. Consider enhancing a quality management program around records; and
   e. Dig Safe was mentioned the *O&M Manual* but not with much details about expectations, procedures, etc. Consider a more thorough and robust policy including miss locates, late tickets, documenting conversations with excavators, investigations, lessons learned, etc.
2. Construction Practices:
   a. Appear to follow minimum requirements with no noted deficiencies;
   b. There are references to engineering providing work packets, but not clear when written procedures are required or how to develop, responsible parties, execution, etc. Consider more robust and clear process for written procedures (both construction and O&M activities); and
   c. Good set of drawings/diagrams for typical installations. Review to ensure higher risk activities are included.
3. Distribution Integrity Management Program:
   a. DIMP appears to be regularly reviewed and updated;
   b. Threat identification is more SME driven, but does consider some external information.[283] Consider moving to a more data driven process; and
   c. Linkage of risk mitigation plans to specific risk results is not clearly documented.
4. Risk Management Program:
   a. Focus is more on personal safety than risk management or public safety; and
   b. Records are a key part of a robust risk management program. Holyoke does not have a common repository for records but believes they are complete. Consider a more robust plan overall, including clearly identifying which records are to be kept, system of record, understanding current gaps and working to improve records, how they are used, etc.
5. Incident and Crisis Management:
   a. Holyoke engaged in an emergency drill in 2019 and is planning on participating in a second drill in the first quarter of 2020. They also discuss and learn from incidents. Consider performing drills and full-scale exercises regularly, which include local emergency first responders and officials.
6. Management Systems:
   a. Awaiting NGA process and will do what is required. Holyoke believes management systems provide benefit by providing for continuous improvement, including but not limited to, industry peer reviews, QA/QC programs and management of change processes.

B.5.6 Field Visit Summary

The Panel visited 8 sites and observed construction and maintenance work including leak repairs, installation of new main as part of GSEP, tie-in of service line and meter move out, and a locate and mark site. More details are provided in Table B-17.

[283] During the Snapshot Review Process, Holyoke reported that it tracks the cause of excavation damage when there is third party damage.

Table B-17: Field Visit Summary

Location No.	Description	Date	Photograph
HOL-1	Gas Leak Repair	8/1/19	
HOL-2	Main Install site preparation; test holes	8/1/19	
HOL-3	Mark-Locate for new riser	8/1/19	
HOL-4	Distribution Team Meeting	8/2/19	No photograph
HOL-5	Change Over, moved meter outside, to LP system; curb valve box paved over	8/2/19	
HOL-6	Swing ties to main valve	8/2/19	
HOL-7	Service Department Safety Meeting	8/2/19	No photograph

Location No.	Description	Date	Photograph
HOL-8	New service installation	8/2/19	

B.6 Liberty Utilities - LIB

B.6.1 System Overview

Liberty Utilities (New England Natural Gas Company) Corp[284] (Liberty) has about 56,500 customers in Fall River and surrounding communities in Southeast Massachusetts. The systems include 619 miles of main, of which 28% is leak prone pipe.[285] Additionally, about 27% of the services are leak prone pipe.

Table B-18: Liberty Utilities System per 2018 PHMSA Data[286]

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-70's Miles/Number	% of System
Mains	619.5	175.2	28.3%	266.6	43%
Services	36,828	9,926	27.1%	8,661	23.5%

There are 38 district regulator stations, with 16 feeding low-pressure systems. Six of the regulator stations have recently been replaced and 8 have had the sensing/control lines modified. About 10,000 meters are inside sets. Liberty operates an LNG facility in Fall River for peak-day support and recently upgraded the facility.

Liberty has 158 gas employees in Massachusetts, which is an increase of about 12% over the last few years.

Liberty reduced regulators to below the MAOP of the pipelines in aftermath of San Bruno event. This caused them to reduce overall system capacity by about 10%. It also demonstrates an openness to learning from the industry.

Liberty reports no over-pressure events in the last five years.

B.6.2 Construction and Maintenance Work Execution

The Panel visited 13 field sites and observed activities related to activities related to construction and maintenance work. More details are provided in Appendix B.6.6.

[284] Liberty Utilities Corporation, the direct parent of Liberty Utilities, is a utility holding company that provides regulated water, wastewater, natural gas, electric and propane/air utility company providing local utility management, service and support to small and mid-sized communities across the US. Through its subsidiaries, it provides natural gas to over 290,000 customers located in Georgia, Illinois, Iowa, Massachusetts, Missouri, New Hampshire, New York, and New Brunswick.

[285] Consistent with the definition in GSEP, leak prone pipe includes cast iron, bare unprotected steel, and coated unprotected steel.

[286] Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

B.6.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.6.6, the Panel observed the following, which was specifically related to Liberty:

- Strengths:
  - Robust leak survey that appears to be beyond minimum code requirements; and
  - Good use of effective inspectors (Best practice):
    - One inspector per site; and
    - Take notes and swing-ties on new installs.
  - Good use of non-mechanical excavation techniques (Best Practice):
    - Pot-holing with vacuum truck; and
    - Air knife to move soil away from pipe.
  - Performed site-specific assessments to identify location of new service and existing buried infrastructure such as gas, water and sewer. This information was then transmitted into the job packages with annotated photos for the construction crews;
  - Upgraded LNG facilities to prepare for peak shaving and potential supply shortages;
  - Mark new main/service after installation (and before paving) to account for lag in updating records;[287]
  - Good use of PPE (with all personnel wearing hard hats, steel-toed boots, safety vests, safety glasses, and gloves when on a job site, regardless of task being performed at the site);
  - Use of rock shield at bottom of the ditch before putting pipe in ditch (Best Practice);
  - Use of air knife in combination with a vacuum truck for safer excavations (Best Practice);and
  - GIS has been in place for over 20 years:
    - New mains are marked after install; and
    - New data is input into GIS system within 2-3 weeks of install.
- Opportunities:
  - Conduct better inspections of pipe during leak repairs and use risk-based analysis to replace pipe while excavation is open. See photograph in Appendix B.6.6;
  - Consider increasing the pace of replacing leak prone pipe to meet the 20-year timeframe envisioned under GSEP, provided it can be done safely;

[287] This was observed before the DPU issued DPU Final Order (Order Adopting Final Regulations in D.P.U. 19-43-A) on October 4, 2019 requiring companies to document their marking of newly installed lines (Final Regulations 220 CMR 99.06.(9).

- Revise system pressure tags on meters; as currently implemented they create an opportunity for confusion (1 out of 2 checked were incorrect); and
- Conduct an emergency preparedness drill as soon as feasible. Preferably, this is a field mock drill involving third parties and governmental agencies. Alternatively, and at minimum, conduct a mock tabletop drill. Make such drills a routine practice.

Liberty demonstrated solid construction practices in the field with use of several best practices. Crews observed were competent. Primarily used two construction companies for main replacement. Packaged 180+ service replacements for bid which was won by a third contractor. Good PPE use on all work sites. Good gas control center given the size of the company.

As shown in Table 8 in Section 8.2.3.1 (see Table B-19 for relevant excerpt), if the pace of renewal in the future remains roughly the same as averaged over the past five years, it appears Liberty is slightly behind the pace needed to meet the 20-year timeframe for replacement of mains envisioned under GSEP.[288] This observation is based on five years, or 25% of the 20-year plan, elapsing without 25% of the work having been completed. Projected year for completion of main replacement at current pace is 2034.

Table B-19: Excerpt from Table 8 (Based on 2013-2018 Pace)

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Service Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (Based upon Current Pace)
LIB	31770	23% reduction 229 to 175 (54)	28% reduction 13,711 to 9,926 (3,785)	2034

B.6.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Liberty Utilities system is set forth in Table B-20, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-20: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Liberty Utilities	53.39	1.32	47.12	1.28
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

[288] Like several other Gas Companies, Liberty indicated during the Snapshot Review Process that the pace of the last five years is not reflective of the future planned pace. Liberty reports it has been increasing the pace each year and are currently on pace to complete replacement of leak prone pipe by 2033 or 2034.

Observations about Liberty Utilities system and renewal programs based on this leak analysis are as follows:

- Overall trend on main leak ratio is slightly downward;
- Overall trend on service leak ratio is flat to slightly downward;
- Leak cause for main reported as corrosion, natural forces and other, which is typical with cast iron and unprotected steel;
- Leak cause for services is reported as corrosion and other, which is typical for unprotected steel services; and
- Consider increasing pace of renewal to stay ahead of overall system deterioration.

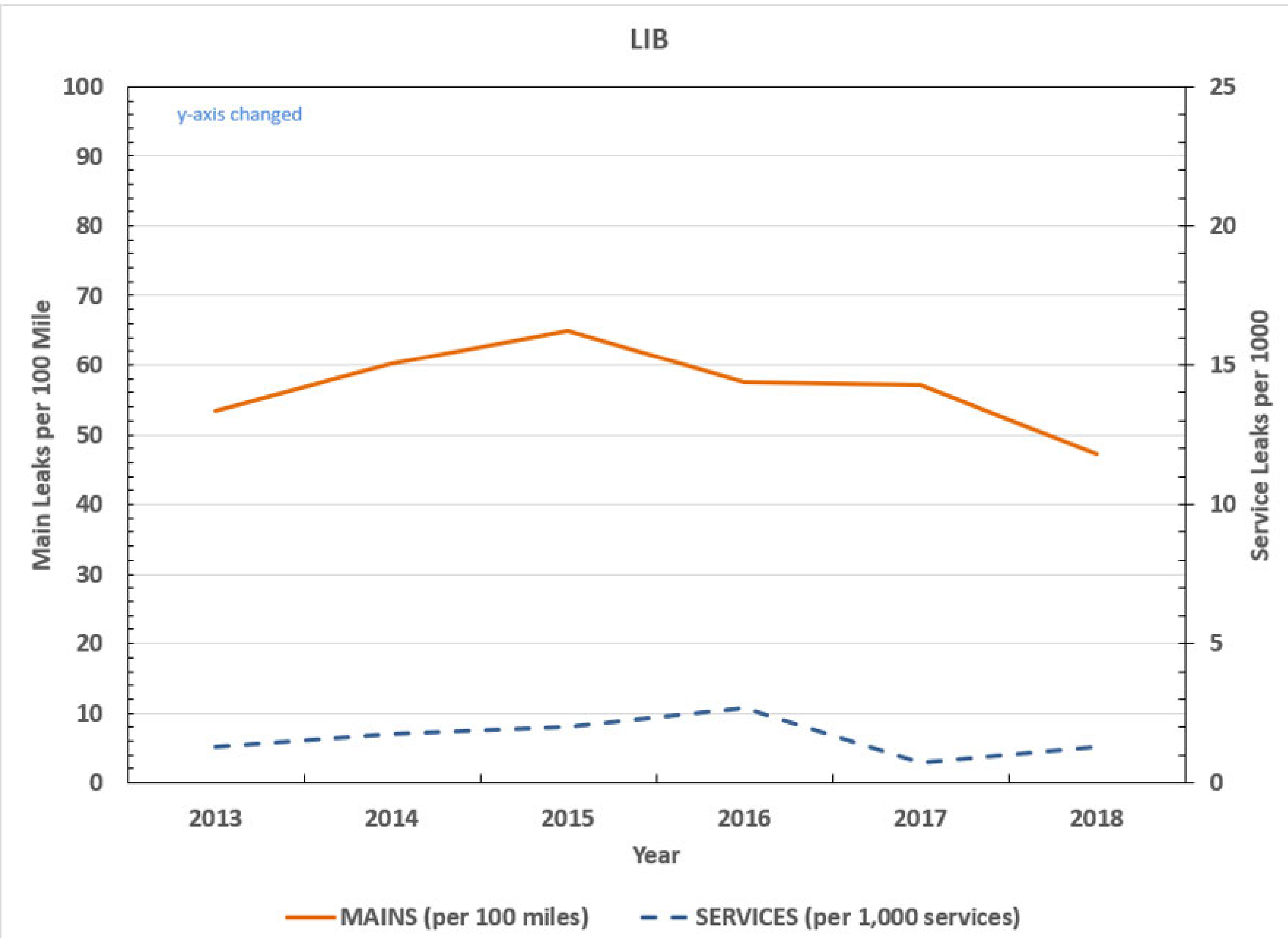


Figure B-8: Liberty Utilities Leak Ratio (Mains and Services)

B.6.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. The *O&M Manual* is well organized and easy to use. While primarily code focused, some best practices as well. No deficiencies to minimum requirements noted. Included a process to deviate from the *O&M Manual*, complete with documentation. The *O&M Manual* is available electronically;
    b. The *O&M Manual* includes some diagrams/drawings for common tasks and activities. Review to ensure higher risk activities are included for clarity;
    c. See records below under risk management. Consider a quality management program around records; and
    d. Small team reviews of the *O&M Manual*. If not doing so, consider including field representation on team to review manual.
2. Construction Practices:
    a. Appear to follow minimum requirements with no noted deficiencies;
    b. There are references to engineering providing work packets, but not clear when written procedures are required or how to develop, responsible parties, execution, etc. Consider more robust and clear process for written procedures (both construction and O&M activities); and
    c. Some drawings/diagrams for typical installations. Review to ensure higher risk activities are included.
3. Distribution Integrity Management Program:
    a. DIMP appears to be regularly reviewed and updated;
    b. Threat identification appears to be more SME driven than data driven. Consider moving to a more data centric approach;
    c. Risk assessments appear to be more SME driven. Consider moving to a more data centric approach;
    d. Calculated risk assessment (Excel-based);
    e. Organizational responsibility for DIMP not clearly documented;
    f. Linkage of risk mitigation plans to specific risk results is not clearly documented;
    g. Consider including facilities in risk ranking; and
    h. Complete program review appears to be done annually, exceeding minimum required intervals.
4. Risk Management Program:
    a. Records are a key part of a robust integrity management program. While Liberty states they have been on GIS for about 20 years, there did not appear to be a quality management program around records;
    b. Reconsidering additional over-pressure protection at district regulators;

c. GSEP is viewed as a positive program, providing planning certainty for Liberty, local communities and contractors;[289] and

d. Liberty reduced regulator pressure settings in aftermath of San Bruno, providing an extra safety margin. This lost them about 10% of system capacity but had no negative impact on customers that we could find.

5. Incident and Crisis Management:

a. Has run a tabletop event but no full scale; and

b. Recommend ICS training and implementation, regular emergency drills, inclusive of full-scale exercises. This should include coordination with local emergency first responders as well as local government agencies;

6. Management Systems:

a. Likes SMS and believes it will be helpful. Waiting for NGA process before beginning implementation; and

b. Some concern about staff accepting program, particularly no retribution. Historical experience suggests people will be reluctant to be transparent.

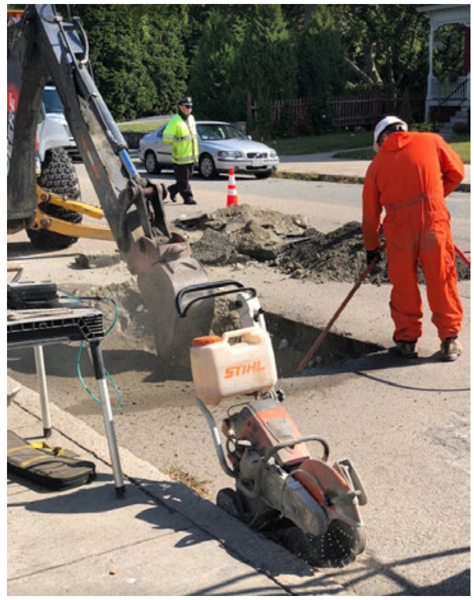
B.6.6 Field Visit Summary

Table B-21: Field Visit Summary

Location No.	Description	Date	Photograph
LIB-1	Main replacement	9/16/19	

[289] During the Snapshot Review Process, Liberty noted that it had been actively involved during the GSEP reconciliation filings at the DPU – advocating for increasing the rate of recovery permitted for Gas Companies from 1.5% to 3.0% to enable an increase in the recovery of costs for pipe replacement. As noted in Section 10.1.11, the DPU recognized the need for an increase in the cap for recovery to reduce risk and that Gas Companies could file for recovery up to 3.0% of revenues.

Location No.	Description	Date	Photograph
LIB-2	Main install	9/16/19	
LIB-3	District Regulator Station	9/16/19	

Location No.	Description	Date	Photograph
LIB-4	Leak Repair, Grade 2	9/16/19	
LIB-5	New service	9/16/19	

Location No.	Description	Date	Photograph
LIB-6	New service	9/16/19	
LIB-7	New low-pressure main	9/16/19	
LIB-8	Distribution Center	9/16/19	

Location No.	Description	Date	Photograph
LIB-9	Main install	9/17/19	
LIB-10	Service install (180 bundled)	9/17/19	
LIB-11	Service Center: Regulator station, LNG, Gas control, fabrication of piping	9/17/19	

Location No.	Description	Date	Photograph
LIB-12	Leak Repair, Grade 2	9/17/19	
LIB-13	Tie-in	9/17/19	

B.7 Middleborough Gas & Electric - MID

B.7.1 System Overview

The Middleborough Gas & Electric (Middleborough) natural gas distribution system serves Middleborough, Massachusetts. This is a municipal system and the general manager reports to a 5-person elected Commission. The system consists of approximately 107 miles of main and 4853 services. A little more less than 7% of the mains are leak prone pipe. About 24% of the mains are pre-code vintage. For services, about 4% are leak prone material and about 6% are pre-code vintage.

Table B-22: Middleborough System per 2018 PHMSA Data[290]

	Total System Miles/Services	Leak Prone Miles/Number	% of System	Pre-1970s Miles/Number	% of System
Mains	107.1	7.4	6.9%	23.6	22%
Services	4,853	177	3.6%	266	5.5%

There are 10 regulator stations, five of which serve the low-pressure system. There are 165 inside meter sets on the low-pressure system. Middleborough reports it is in the midst of moving indoor meters outside wherever feasible.

Middleborough reports no over-pressure events on low-pressure system. They had an event on their 60 psig system but it was an excursion of 61 psig and did not require remediation.

This is a small system, with 15 gas employees. They have had significant retirements over the last 6 years.

Natural gas supply comes from the Algonquin Pipeline. There are three interconnects with Columbia Gas for system pressure support during the peak demand system. Middleborough also operates an LNG plant for peak shaving. The LNG plant is a tank only (with vaporization facilities), so it is dependent upon trucks to refill. The LNG plant holds a 2 day supply (not a peak day).

B.7.2 Construction and Maintenance Work Execution

The Panel visited 7 field sites and observed activities related to activities related to construction and maintenance work. More details are provided in Appendix B.7.6.

[290] Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

B.7.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.7.6, the Panel observed the following, which was specifically related to Middleborough:

- Strengths:
  - Tight-knit small team in relatively small service area. This enables clear communication channels and has the benefit that people often remember the prior work they personally performed;
  - Performs frequent leak surveys and does not carry over any leaks – all discovered issues are repaired in the year found;
  - Repair Grade 2 leaks faster than required by regulation; based on assessment of potential consequences;
  - Appears to use risk and data frequently to make decisions;
  - Prohibit cell-phone on work site (distraction to workers) (Best Practice);
  - Had good legacy records (drawings on Mylar) and good records of recently installed assets;
  - Conducted a mock emergency tabletop drill with local officials in September 2019;
  - Good use of checklists on work sites; and
  - Mark and locate personnel often installed assets.
- Opportunities:
  - Increase safety practices around movement of steel plates;
  - Ensure every visitor to work site has appropriate PPE (including steel-toe boots);
  - Establish and routinely perform emergency response exercise (include Middleborough Commission in some drills as part of managing external stakeholders);
  - Work to improve documentation – around maintenance, records, etc. Very dependent upon institutional knowledge and key people, improving documentation lessens risk of losing key personnel;
  - Continue push to get records into electronic GIS;
  - Develop access to deeper set of technical experience and skills; and
  - Be aware of the pitfalls of operating with overconfidence.

Middleborough benefits from its size and cohesive workforce as well as a relatively small and simple system. Like other small companies, it is challenged by availability of fewer resources, a lack of deep technical expertise, and a lack of business support structures. Construction crews met the challenges presented by main installation. Senior management visited the work site, but this appeared to be a visit to connect with the Panel and not a routine practice to better understand the work and challenges in the field.

B.7.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Middleborough system is set forth in Table B-23, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-23: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Middleborough	5.84	7.53	2.81	2.68
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Middleborough's system and renewal programs based on this leak analysis are as follows:

- Leak ratio for main and services trending downward
- Majority of leak causes are age and time dependent, suggesting ongoing focus on older and leak prone assets appropriate

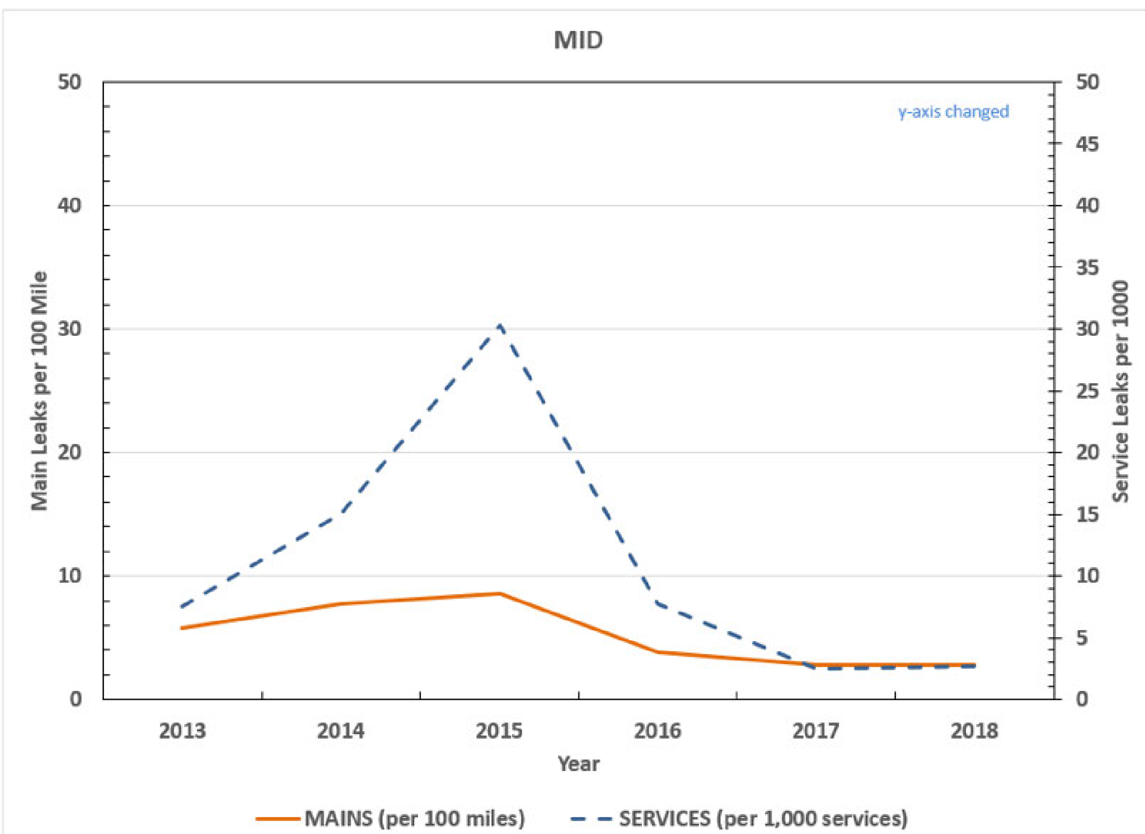


Figure B-9: Middleborough Leak Ratio (Mains and Services)

B.7.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. The *O&M Manual* is well organized and easy to use, not as legal/regulatory focused as others. Primarily code focused, with no deficiencies to minimum requirements noted;
    b. The *O&M Manual* includes some diagrams/drawings for common tasks and activities. Review to ensure higher risk activities are included for clarity (for both O&M and construction activities);
    c. All leaks are repaired/cleared every year. Good practice;
    d. Does do some pressure tests to higher pressures. While this was done to future replacement/renewal, it also provides an added safety margin on the system;
    e. Dig Safe meets minimum requirements but not a lot of detail. Consider a more robust policy, including late tickets, miss locates, documenting conversations with excavators, etc.; and
    f. See records below under risk management. Consider a quality management program around records.
2. Construction Practices:
    a. Appear to follow minimum requirements with no noted deficiencies; and
    b. There are references to engineering providing work plans, but not clear when written procedures are required or how to develop, responsible parties, execution, etc. Consider more robust and clear process for written procedures (both construction and O&M activities).
3. Distribution Integrity Management Program:
    a. DIMP appears to be regularly reviewed and updated;
    b. Threat identification is more SME driven. Consider moving to a more data driven approach;
    c. Risk assessments appear to be more SME driven, but they do have an Excel-based calculation;
    d. Linkage of risk mitigation plans to specific risk results is not clearly documented; and
    e. Organizational responsibility for DIMP is not clearly identified.
4. Risk Management Program:
    a. Should have remaining leak prone pipe replaced within 10 years at current pace. They have the resources to perform at this level but may want to consider accelerating the pace to reduce risk. Prioritization appears to be mainly on paving schedule;
    b. Records are a key part of a robust risk management program. Middleborough began work on GIS and is about 30% complete in 2019. Consider broader records program to support risk management;
    c. Do not view risk holistically nor consider unknowns;

5. Incident and Crisis Management:
    a. Participated in first drill (table top with local officials) in September. Consider making table top drills and full scale field exercises, to include local emergency first responders and officials, part of a more routine practice.
6. Management Systems:
    a. Will participate in NGA process.

B.7.6 Field Visit Summary

Table B-24: Field Visit Summary

Location No.	Description	Date	Photograph
MID-1	2 Vine	9/18/19	
MID-2	Main replacement, tie-in	9/18/19	

Location No.	Description	Date	Photograph
MID-3	Mark and Locate	9/18/19	
MID-4	Mark and Locate	9/18/19	
MID-5	Mark and Locate	9/18/19	

Location No.	Description	Date	Photograph
MID-6	Regulator Station	9/18/19	
MID-7	LNG Facility	9/18/19	

B.8 National Grid - NGC

B.8.1 System Overview

National Grid[291] is an Investor-owned utility with operations in a variety of states.[292] The systems in Massachusetts serve customers in 116 cities and towns.[293] As shown in Table B-25, about 28% of mains and almost 15% of services are leak prone[294] materials. The largest service area is Boston, and 41% of those mains are leak prone materials. About 40% of the mains and almost 34% of the services are pre-70's vintage.

Table B-25: National Grid System per 2018 PHMSA Data[295]

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-1970s Miles/Number	% of System
Mains	11,130.3	3,082.1	27.7%	4,430.9	39.8%
Services	761,382	110,281	14.6%	254,474	33.9%

National Grid uses district regulators to protect low-pressure systems, which account for about 350,000 of service lines (almost half). Company decided it is not practical to add over-pressure protection at the house and is reviewing tertiary OPP at the regulator stations.

National Grid reports 13 over-pressure events on low-pressure systems in the prior five years. The majority were installation error, one equipment failure and three instances of incorrectly sized regulators. Several of the events impacted a number of customers.

Systems are generally served by Tennessee Gas Pipeline (TGP), Algonquin Gas Transmission (AGT), and LNG peaking facilities. LNG appears to account for about 40% of peak day supply. The LNG facilities are older (40-50 years old).

B.8.2 Construction and Maintenance Work (Execution)

The Panel visited 28 sites and observed construction and maintenance work including leak repairs, installation of new mains as part of GSEP, new service install, and tie-in of service line. More details are provided in Appendix 6.c.

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291 Boston Gas Company and Colonial Gas Company (each d/b/a National Grid).

292 In the US, National Grid provides electricity and natural gas to over 3.4 million electric customers and 3.5 million gas customers. It is part of a larger corporate group that is owned by National Grid in the United Kingdom, where National Grid provides the national natural gas transmission network, along with managing electricity supply and transmission.

293 In the Snapshot Review Process, National Grid states it "operates the second oldest gas distribution company in the country."

294 Consistent with the definition in GSEP, leak prone pipe includes cast iron, bare unprotected steel, and coated unprotected steel.

295 Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

B.8.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix 6.c, the Panel observed the following, which was specifically related to National Grid:

- Strengths:
    - Strong asset management program and good system knowledge overall:
        - Recognized increase in service and main leak trends and reacted with additional capital investment (beyond GSEP); and
        - Analyzed available data to see trends – Boston contains most of leak prone materials and National Grid is analyzing and monitoring it separately.
    - Going beyond compliance with a more robust DIMP and appears to utilize its DIMPs as a vehicle for developing a better understanding and mitigating risks associated with its gas systems;[296]
        - The checklists used by National Grid's contractor crews, called Standard Operating Procedures (SOPs) by National Grid, were particularly well done, including good drawings representing good examples of site-specific work plans and checklists (Best Practice);[297]
    - Being a learning organization (e.g., National Grid showed itself to be a learning organization when it recognized a gap that existed in the aftermath of Merrimack Valley and developed an SOP for all work that interrupts gas flow);
    - Effectively use strong, competent contractor crews on complex jobs (Best Practice);[298]
    - Use of pre-fabricated distribution regulator stations (Best Practice);
    - Use of grading system (i.e., A, B, C, and D) to rate qualification of field technicians (Best Practice);
    - Carry a card using a QR code to display tasks for which individual is Operator Qualified to perform (Best Practice);

[296] As discussed in Section 5.3, the DIMPs that go beyond compliance demonstrate continued learning and evolution of the program. Among other characteristics, a more mature DIMP increasingly relies more on data, becoming less reliant on the opinions of its SMEs, demonstrates a strong link between the plan and decision making on which projects to undertake, has a clear organizational responsibility for the plans, with a clear connection to how the distribution integrity management plans interact with the company's risk management approach. By its very nature, opportunities to continue to improve the DIMP exist.

[297] For instance, the Panel observed one crew undertaking a replacement and tie-in of a dual-pit district regulator station in which the National Grid checklists were well defined, clear, and used by the crew. The procedure was several pages long with numerous steps and tasks on each page. Many of the tasks required the crew to call into Gas Control to obtain permission to proceed to the next step. The crew found this step particularly helpful in providing another layer of attention to the project steps. Each step required the crew chief's signature. Similar useful site-specific work procedures were used at other National Grid work sites.

[298] The crew observed by the Panel at NGC-18 was one of the top three crew chiefs and crews the Panel observed in the over 150 sites. As discussed in Section 9.1.5 and Footnote 119, the Panel received outstanding job briefings with excellent hazard identification at this location.

- ○ Have all personnel wear basic personal protective equipment (PPE) including hard hats, steel-toed boots, safety vests, safety glasses, and gloves when on a job site, regardless of task being performed at the site (Best Practice);
- ○ Require personnel to wear gas monitors on their hard hats while on work sites (Best Practice);
- ○ Involve gas control with complex site-specific procedures (e.g., verify field gage pressure) (Best Practice);
- ○ Clear procedure to avoid static electricity with purge procedures and follow requirements to avoid air-gas-static that could create a fire (Best Practice);
- ○ Mark new main/service after installation (and before paving) to account for lag in updating records (Best Practice); [299]
- ○ Position trucks and heavy equipment to protect workers from traffic (Best Practice);
- ○ Set clear expectations in procedures for regulatory maintenance, including when full tear down and soft goods replacement is required (Best Practice);
- ○ Effective response to a line strike that occurred by a third-party;
- ○ Robust and outstanding emergency response programs and practices. This includes:
  - – Standing up its own Incident Command Center immediately after the Merrimack Valley incident and anticipating the electric outage that occurred;
  - – Executing regular mock exercises/drills, inclusive of external partners (Best Practice). Including a tabletop exercise with local authorities on August 6, 2019; and
  - – Being led by a Vice-president of Emergency Response.
- ○ Contractor Best Practices observed at certain National Grid work sites:
  - – Use of lift plan while lifting steel pipe from truck onto site;
  - – Use of guidance safe stick when lifting steel plates at work sites;
  - – Hand digging all crossings before starting excavation of trench;
  - – Put cones near crossings for more visibility for excavator operator;
  - – Putting sand on the pavement to preserve skid steer tires and protect road pavement;
  - – Saw cut and remove the pavement all at once then put a thin layer of asphalt over cut area to be removed each day to accommodate that day’s work;
  - – Having crew on perform stretching exercises before engaging in physical work day; and
  - – Install cones near crossings to increase visibility of the excavator operator.
- ○ Good access to GIS records on laptops; and
- ○ Gas control center was well-managed and demonstrated a thorough understanding of needs and challenges.

[299] This was observed before the DPU issued DPU Final Order (Order Adopting Final Regulations in D.P.U. 19-43-A) on October 4, 2019 requiring companies to document their marking of newly installed lines (Final Regulations 220 CMR 99.06.(9).

- Opportunities:
  - Identify and address the various barriers to getting work accomplished (for example, at one worksite, a crew waited for police detail to start work yet at worksite a block away, police detail was present and confirmed by a call to headquarters that other police officers were available to work);
  - Prioritize addressing barriers where work has higher risk-profile (for example, work site without police detail was a Grade 2 leak repair on a busy street with pedestrian traffic in front of City Hall; work site where police detail was present was Grade 2 leak repair in front of individual home);
  - Add personnel redundancy to critical work activities, including work planning to minimize disruption from staff absences (absence of planner on sick leave created confusion and wasted time for work crews);
  - Consider whether extensive SOPs are adding sufficient benefit at less complex jobs;
  - Develop more robust process and better quality management around distribution records:
    - Street markings were different than drawings;
    - Records from 2001 install were inaccurate; and
    - Crews expect records to be inaccurate about 50% of the time.
  - Allow room for consideration of unknowns in thinking about operations, records and risks;
  - Increase use of independent, engaged inspectors with goal of reaching ratio of inspector to work site closer to 1:1 or 1:2;
  - Build robust process to ensure independence and competency of inspectors;
  - Track critical gas events, like over-pressurizations on low pressure systems, and conduct root cause analysis as means to learn from events;
  - Develop and implement plan to lower the number of over-pressure events;[300]
  - Consider adding and upgrading key assets to reduce the number of over-pressure events on low pressure systems;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking;
  - Continue work to improve labor /management relationships with certain individuals to focus on common goal of ensuring gas pipeline safety;

[300] As discussed. In Section 9.5, the three large Gas Companies (which includes National Grid) collectively experienced just under 40 over-pressure events on their low-pressure systems and over 85 over-pressure events on their medium- and high-pressure systems (with the vast majority being slight variances above MAOP) since 2013.

- Enhance job briefings to move beyond administrative process; work to improve hazard identification during job briefs, especially when SOPs are not in use; and
- Review Grade 2 processing to fix leaks more quickly and to ensure leaks are not getting lost in the system before being repaired.

National Grid is a large company with a complex system. It benefits from the presence technical expertise, corporate planning and availability of resources. It is challenged by the fact that approximately half of the remaining leak prone pipe (mains and services) in Massachusetts are in the Boston Gas Company system, which is part of National Grid Boston Gas. It is likely the vast majority of leak prone mains and services are located in the Greater Boston area where replacement work is particularly challenging.[301]

In addition, as discussed in B.8.4, the number of miles of mains with discovered leaks increased between 2013 and 2018. This suggests National Grid may not be replacing the right pipe at the right pace.

As shown in Table 8 in Section 8.2.3.1 (see Table B-26 for relevant excerpt), if the pace of renewal over the last five years remains roughly the same in the future, it does not appear National Grid is on pace to meet the 20-year timeframe for replacement of mains envisioned under GSEP. This observation is based on five years, or 25% of the 20-year plan, elapsing without 25% of the work having been completed. Projected year for completion of main replacement at current pace ranges from 2020 to 2052.

Table B-26: Excerpt from Table 8

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Service Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (Based upon Current Pace)
NGC		15% reduction 3,634 to 3,082 (552)	15% reduction 129,971 to 110,281 (19,690)	2046
BOS	*1640*	*13% reduction 3,230 to 2,806 (423)*	*14% reduction 114,663 to 98,291 (16,372)*	*2051*
ESS	*4547*	*13% reduction 103 to 90 (13)*	*15% reduction 4,965 to 4,204 (761)*	*2052*
COL	*11856*	*16% reduction 181 to 152 (29)*	*19% reduction 5,759 to 4,641 (1,118)*	*2045*
CAP	*2066*	*72% reduction 121 to 34 (87)*	*31% reduction 4,584 to 3,145 (1,439)*	*2020*

301 As discussed in Section 8.2.3.3, the Panel generally would expect projects to be prioritized based to target replacements in locations where the risk is highest. Generally, this is in cities, where there is an abundance of hard surfaces and high-density housing. Yet these are particularly difficult projects. In densely-populated locations, permitting and construction is most difficult and costs are likely to be high. They also likely correspond to areas in which the number of leaks are greater and the potential adverse impacts to the public is high.

National Grid is also challenged by multiple layers of approvals, silos of work, and many hand-offs between silos, all of which provide opportunity for missed communications. Moreover, the segmentation created attitudes on the work sites of only considering or addressing concerns within their sphere without ensuring communications about the issue to the appropriate team.

Historically, National Grid has been the subject of substantial oversight by the DPU. As discussed in Section 10.1.8, in the three years between 2016-2018, National Grid was the only company that had its DIMP audited by the DPU. Furthermore, it was audited 16 times within this period. National Grid also received 5 out of the 9 warning letters and 8 out of 13 of the NOPVs issued by the DPU during that time.[302]

National Grid's management raised concerns about the numerous barriers it faces in conducting construction during the presentations in Phase 1. The Panel observed the impacts of these barriers at almost every site visited. At one point, someone said "we are always waiting on something" and the Panel found that to be true. This creates discontinuities in workflow which ultimately increases risk. The presence and impact of these barriers seems to be more prevalent at National Grid than at any of the other Gas Companies. Whether National Grid is truly encountering more barriers or is less effective at addressing them is unclear.

The Panel observed a wide variety in the quality of the work performed over the 28 work sites visited.

B.8.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.[303]

Table B-27: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
National Grid	57.48	3.42	77.56	3.11
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

[302] None of the warning letters issued to National Grid refer to, or appear to have arisen from, the inspections. Only three of the NOPVs appear to reference the inspections.

[303] In the Snapshot Review Process, National Grid proposed a different method to calculate its leak ratio. It proposed using additional information available to it, but excluding those leaks of unknown location or cause that the Panel included. While NGC calculated lower leak rates, the overall trend was basically unchanged. To maintain consistency across these analyses, the Panel opted *not* to adopt the calculation proposed by NGC and *did not* modify the leak rates in Table B-27 using the NGC-proposed methodology. This discussion highlights the need for the DPU to develop consistent metrics and reporting requirements for the Gas Companies to permit consistent, accurate, and feasible comparisons as part of the effort to track changes in leak rates across Gas Companies.

Observations about National Grid's system and renewal programs based on this leak analysis are as follows:

- General trend on main leak ratio is flat to increasing and the overall ratio is comparatively high;
- General trend on service leaks is flat;
- Reported causes for main leaks are other, corrosion and natural force. This is typical of cast iron and unprotected steel systems;
- Reported causes for service leaks are corrosion and other, typical of the types of assets in the system; and
- Consider increased renewal for mains and services is to stay ahead of overall system deterioration.

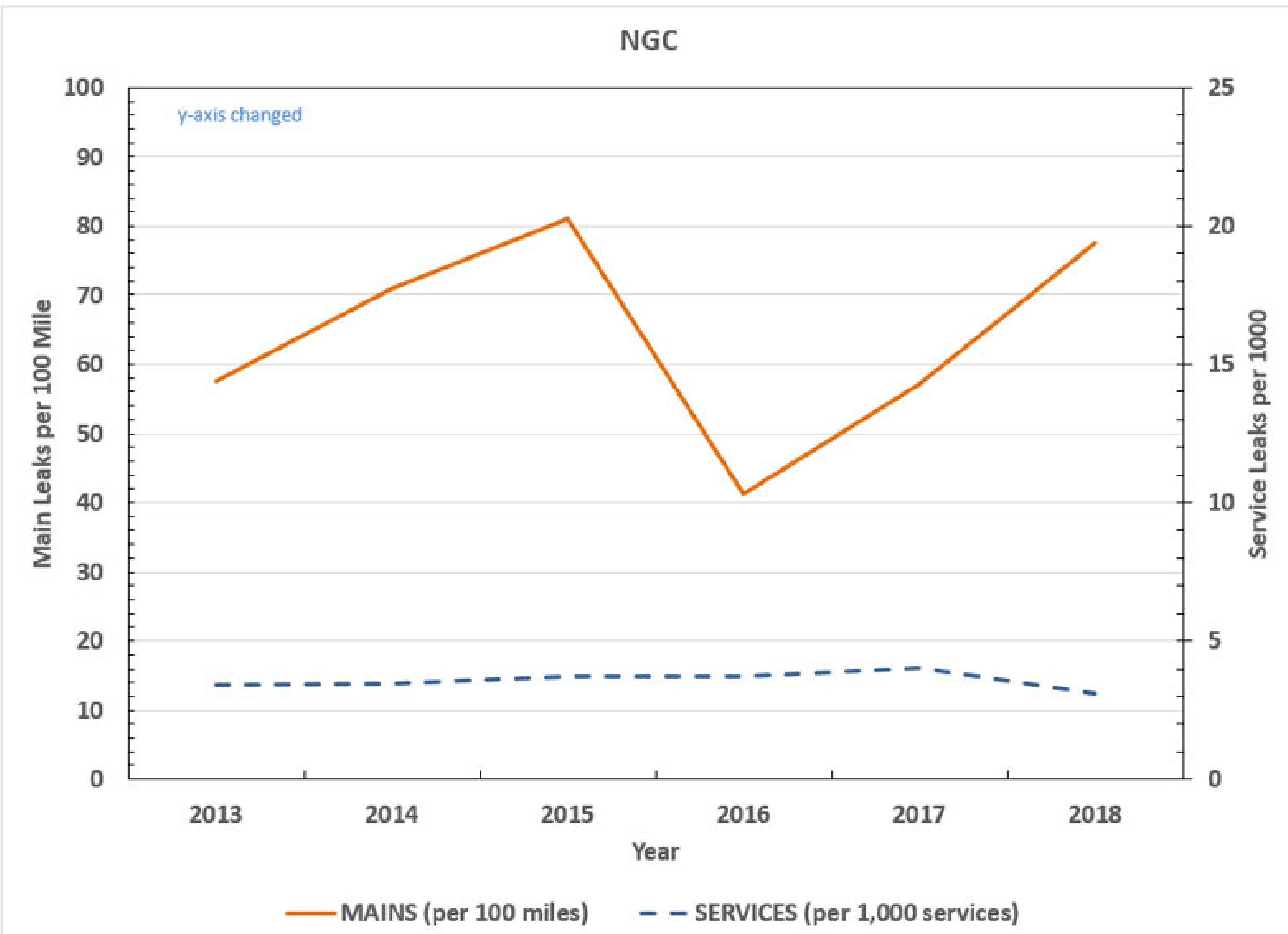


Figure B-10: **National Grid Leak Ratio (Mains and Services)**

B.8.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. A large *O&M Manual* can be overwhelming to some. Electronic version/searchability helps ameliorate size. Visual aids also make it more usable (stop, more info, etc.);
    b. Primarily regulatory code focused with some additional information (legacy records, sewer laterals as examples). No deficiencies noted against minimum requirements;
    c. There are a lot of drawings/diagrams of typical installations and practices, clearly identifying expectations. Not all higher risk activities have drawings/diagrams to help provide clarity and reduce risk;
    d. Procedures in the O&M manuals are generic and it is not always clear when unique, written procedures are required nor who is responsible to develop and execute;
    e. While record requirements are outlined, there does not appear to be a quality management program around records;
    f. Clear expectations for regulator maintenance, including when full tear down and soft goods replacement is required. This is a best practice; and
    g. Consider clarifying Dig Safe and excavation procedures around late tickets, miss locates, rescheduling locates, etc. Also clarify documentation requirements.
2. Construction Practices:
    a. A number of drawings/diagrams for typical installations. Review to ensure higher risk activities have typical diagrams and clear procedures (or require written procedures);
    b. No deficiencies to minimum requirements noted; and
    c. Various references to written procedures. However, there did not appear to be clarity around what is included in written procedures, responsible parties (develop, review, execute, etc.).
3. Distribution Integrity Management Program:
    a. DIMP appears to be actively managed;
    b. Threat identification is more comprehensive and includes some external information;
    c. Risk assessment is calculated and appears to be more data driven with some SME input;
    d. Risk results appear to be used to drive risk mitigation actions. However, these results are by region and not segmented to lower level;
    e. Additional performance measures beyond minimum appear to be in use;
    f. Linkage of risk mitigation plans to specific risk results is not clearly documented; and
    g. Facility risk plan mentioned but not provided/verified.
4. Risk Management Program:
    a. Appear to think about risk in a more holistic manner (understand system risk, mitigate, measure);

b. Appear to understand the difference between process and personal safety;
c. Appear to understand that supply risk increases overall safety risk; and
d. Believes GSEP is moving at appropriate pace and is providing planning stability (for the company as well as local communities and contractors).

5. Incident and Crisis Management:
   a. Performs at least 2 drills annually and includes outside parties;
   b. Organizational structure includes a VP for emergency planning (responsible for both gas and electric);
   c. Plan includes clear roles and responsibilities;
   d. Recognized more robust communication plan needed in aftermath of Merrimack;
   e. Local differences create need for emergency response plans unique to each area; and
   f. Root cause analysis considers the 10 elements of pipeline safety management (RP1173).

6. Management Systems:
   a. Began moving beyond compliance prior to 2010; and
   b. 2018 – began implementing RP1173.

c. Field Visit Summary

Table B-28: Field Visit Summary

Location No.	Description	Date	Photograph
NGC-1	NGC Service Center	9/26/19	

Location No.	Description	Date	Photograph
NGC-2	Main install	9/26/19	
NGC-3	Gr. 2 Leak Report	9/26/19	
NGC-4	Gr. 2 Leak Repair	9/26/19	

Location No.	Description	Date	Photograph
NGC-5	New Construction/ expansion	9/26/19	
NGC-6	District Regulator Station	9/26/19	
NGC-7	Cast-iron Encroachment	9/26/19	

Location No.	Description	Date	Photograph
NGC-8	Main install	9/26/19	
NGC-9	Gr. 2 Leak Repair	9/26/19	
NGC-10	New main construction	9/27/19	

Location No.	Description	Date	Photograph
NGC-11	Grade 2 Leak	9/27/19	
NGC-12	New service	9/27/19	
NGC-13			Gr. 1 Leak call, didn't
NGC-14	Line Strike	9/27/19	

Location No.	Description	Date	Photograph
NGC-15	Grade 2 Leak, Cast Iron Tee	9/27/19	
NGC-16	Meter install	9/27/19	
NGC-17	NGC Service Center and Gas Control	9/27/19	
NGC-18	New main construction, expansion	9/28/19	

Location No.	Description	Date	Photograph
NGC-19	Service replacement	9/28/19	
NGC-20	New service	9/28/19	
NGC-21	New service,	9/28/19	

Location No.	Description	Date	Photograph
NGC-22	Bare steel replacement	9/28/19	
NGC-23	Service Center	9/20/19	
NGC-24	Main replacement	9/20/19	

Location No.	Description	Date	Photograph
NGC-25	Regulator pit installation	9/20/19	
NGC-26	New development construction	9/20/19	

Location No.	Description	Date	Photograph
NGC-27	Service Replacement	9/20/19	
NGC-28	Main replacement	9/20/19	

B.8.6 Other Photographs

Figure B-11: Safe Stick for Guiding Steel Plates

B.9 Unitil - UNI

B.9.1 System Overview

Unitil[304] operates in two communities and surrounding areas in Massachusetts. However, they are part of a larger corporation and can call on those resources as needed.[305]

System consists of 246 miles of main and 11,000 services. Leak prone pipe is about 18% of system and accounts for about 74% of leaks. There is some Aldyl-A with no history of leakage.

Table B-29: Unitil System per 2018 PHMSA Data[306]

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-70's Miles/Number	% of System
Mains	273.3	50.1	18.3%	127.3	46.6%
Services	11,070	1,979	17.9%	2,957	26.7%

Unitil operates five district regulator stations with low-pressure systems and two small intermediate pressure (<30 psig) systems.

Systems are fed by Tennessee Gas Pipeline (TGP), a propane air plant and an LNG plant. There is little growth on the system. The LNG plant supplies 1% of peak day requirements.

B.9.2 Construction and Maintenance Work (Execution)

The Panel visited eight sites and observed construction and maintenance work including leak repairs, installation of new main as part of GSEP, tie-in of service line and meter move out, as well as a locate and mark site. More details are provided Appendix B.9.6.

B.9.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.3.6, the Panel observed the following, which was specifically related to Unitil:

- Strengths:
  - Going beyond compliance with more robust DIMP; appears to utilize DIMP as a vehicle for developing a better understanding and mitigating risks associated with its gas systems;[307]
  - Good historical records (with GIS system and paper);

[304] Unitil or Fitchburg Gas and Electric Light Company.

[305] Unitil is a public utility holding company with affiliates that include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc. Together, Unitil's operating utilities serve approximately 104,978 electric customers and 81,309 natural gas customers in Maine, Massachusetts, and New Hampshire.

[306] Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

[307] As discussed in Section 5.3, the DIMPs that go beyond compliance demonstrate continued learning and evolution of the program. Among other characteristics, a more mature DIMP increasingly relies more on data, becoming less reliant on the opinions of its SMEs, demonstrates a strong link between the plan and decision making on which projects to undertake, has a clear organizational responsibility for the plans, with a clear connection to how the distribution integrity management plans interact with the company's risk management approach. By its very nature, opportunities to continue to improve the DIMP exist.

  - Perform mark and locate for both gas and electric;
  - Maintain good legacy records;
  - Setting monitors at regulator stations below MAOP (Best Practice); and
  - Repair Grade 2 leaks faster than required by regulation based on potential consequences (ensuring all Grade 2 leaks are repaired within six months and Grade 3 leaks in two years or less).
- Opportunities:
  - Review abandonment process and procedures:
    - (i) To ensure personnel have appropriate operator qualifications for gas tasks;
    - (ii) To ensure location of plug outside of foundation; and
    - (ii) To identify the time lime for completion of abandonment after meters are removed from inside homes;
  - Ensure budget concerns do not adversely impact safety;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking;
  - Consider whether the use of an unvented sunshade over live gas work creates potential hazard by trapping gas if unexpected release;
  - Review work sequences when third-party plumber is involved at worksite;
  - Require all workers on site, including plumbers, to abide by PPE requirements; and
  - Conduct an emergency preparedness drill as soon as feasible. Preferably, this is a field mock drill involving third parties and governmental agencies. Alternatively, and at minimum, conduct a mock tabletop drill. Make such drills a routine practice.

B.9.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Unitil system is set forth in Table B-30, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-30: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Unitil	62.97	32.79	40.61	26.11
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Unitil's system and renewal programs based on this leak analysis are as follows:

- Leak ratios for mains and services are generally trending downward;
- Leak ratios for mains and services are comparatively high;
- Leak causes are reported as corrosion, natural forces and other for mains, which is typical for this type of system;
- Leak causes are reported as corrosion, equipment failure and other for services; and
- Recommend continuing pace of renewal and monitoring to keep up with overall system deterioration.

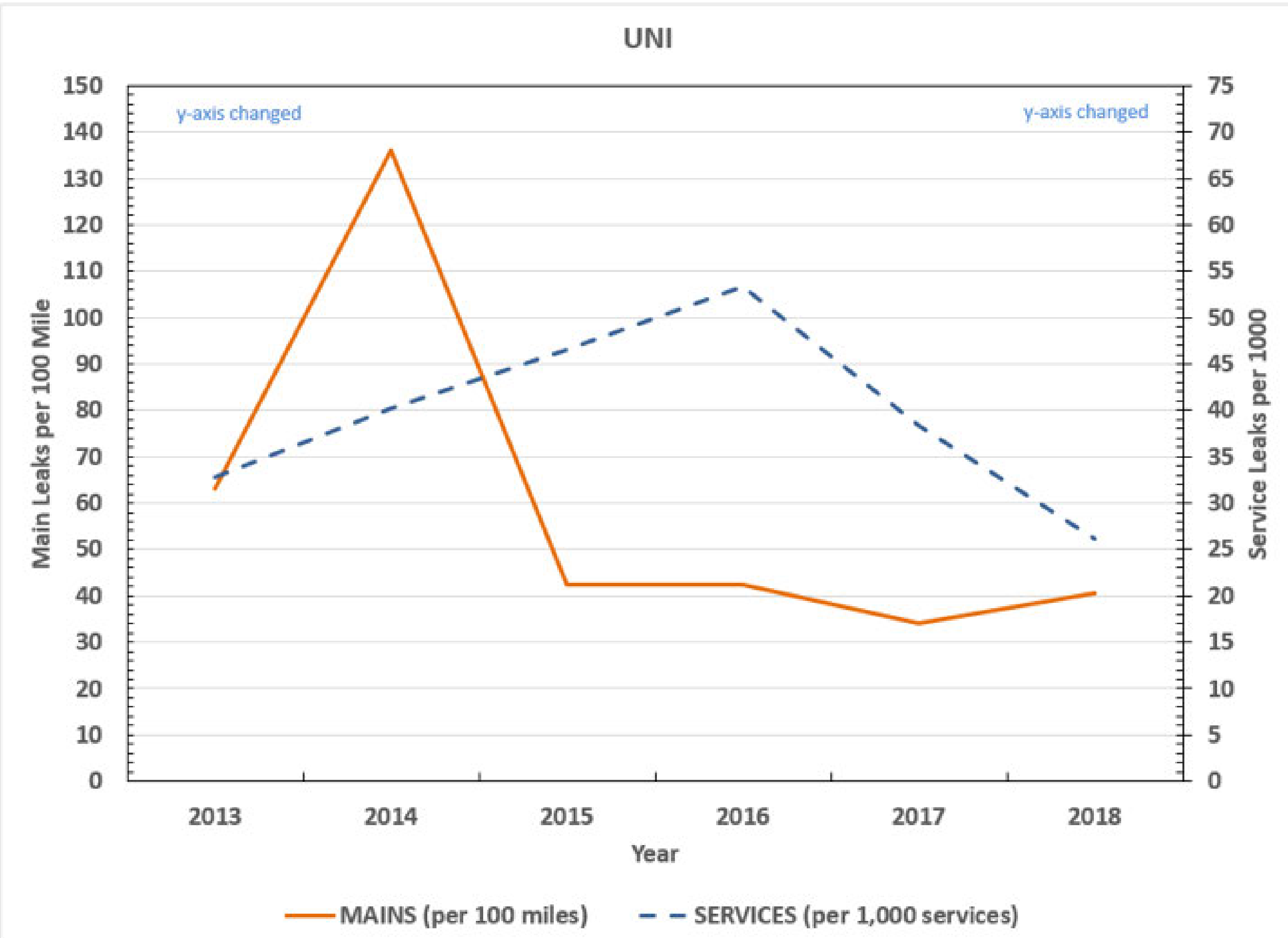


Figure B-12: **Unitil Leak Ratio (Mains and Services)**

B.9.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

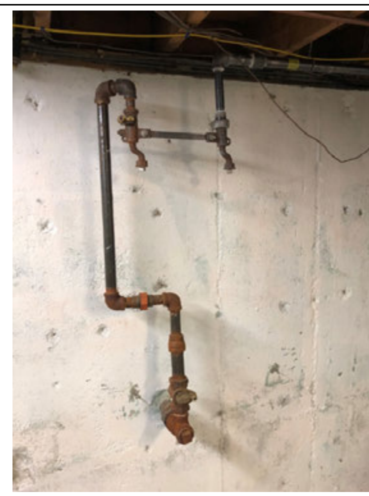
1. Operations and Maintenance:
   a. The *O&M Manual* is well organized and easy to use. While primarily code focused, some best practices noted below. No deficiencies to minimum requirements noted;
   b. The *O&M Manual* includes some diagrams/drawings for common tasks and activities. Review to ensure higher risk activities are included for clarity;
   c. Aggressive approach to leak repair, ensuring all grade 2 leaks are repaired within 6 months (requirement is 12 months). Also works to clear grade 3 leaks within 2 years – primarily by renewal (uses grade 3 leaks and aging to help prioritize renewal);
   d. Identifies higher risk excavators and uses standby to help mitigate risk to assets. This includes leak prone pipe in congested areas and repeat offenders. Fitchburg City government is on repeat offender list;
   e. Best practices set forth in O&M include: inspect valves every 5 years; set monitors below MAOP; guidance when to install SCADA, monitor inlet/outlet pressure at every station, aggressive leak repair; and
   f. See records below under risk management. Consider a quality management program around records.
2. Construction Practices:
   a. Appear to follow minimum requirements with no noted deficiencies;
   b. There are references to engineering providing work packets, but not clear when written procedures are required or how to develop, responsible parties, execution, etc. Consider more robust and clear process for written procedures (both construction and O&M activities); and
   c. Good set of drawings/diagrams for typical installations. Review to ensure higher risk activities are included.
3. Distribution Integrity Management Program:
   a. DIMP appears to be actively managed;
   b. Threat identification is more comprehensive and includes some external sources;
   c. Calculated risk assessment;
   d. Risk assessments appear to be more data driven with some SME input;
   e. Risk results appear to drive risk mitigation actions;
   f. Consider including facilities in risk ranking; and
   g. Consider more frequent program review on an annual basis (currently done at minimum required intervals).

4. Risk Management Program:
   a. Can increase renewal of leak prone pipes in Massachusetts - have resources to accomplish this. Currently limited by legislation. Since DPU has granted some waivers, consider evaluating if local communities will work with you to increase renewal rate and faster plan;
   b. Appears to be removing district regulator stations as they convert low pressure to regular distribution pressures. Evaluate if you want to eliminate all of them – they are useful tools to manage the size of an outage when lines are hit or otherwise break; and
   c. Records are a key part of a robust risk management program. Unitil recognizes the value of records and began improving records in 2010. Mains are in GIS but services are not. Continuing to improve asset knowledge (new and legacy).
5. Incident and Crisis Management:
   a. New employees get IC training and assigned an ER role for which they are trained, generally follow tech experience, reviews other ER plans for lessons learned;
   b. Conducts 2 full scale mock drills each year plus additional tabletops;
   c. Has an outage management system outside firewall so can access it: create packages of customer names based on which valves closed. Ready to be printed and handed out;
   d. Get real practice by helping Electric side respond to outages; and
   e. Lessons from Merrimack Valley – didn't consider how to manage impact to customers (hotels, heaters, etc.).
6. Management Systems:
   a. Risk management systems are some of the more robust, and some of the items speak to safety management; and
   b. No clear plans to implement.

B.9.6 Field Visit Summary

Table B-31: Field Visit Summary

Location No.	Description	Date	Photograph
UNI-1	Contractor, new main	10/11/19	

Location No.	Description	Date	Photograph
UNI-2	Main construction	10/11/19	
UNI-3	Customer re-connect, meter removed 3 years earlier	10/11/19	
UNI-4	Locate and mark	10/11/19	

Location No.	Description	Date	Photograph
UNI-5	Main replacement, rock ledge	10/11/19	
UNI-6	Service replacement, rock wall	10/11/19	
UNI-7	Main Construction	10/11/19	

Location No.	Description	Date	Photograph
UNI-8	Take Station, TGP	10/11/19	

B.10 Wakefield Municipal Gas & Light - WAK

B.10.1 System Overview

The Wakefield Municipal Gas & Light (Wakefield) system serves the Wakefield area and is a municipal system. The system includes almost 27% leak prone mains as well as almost 17% leak prone services. About 27% of the main and 17% of the services are pre-70's vintage.

Table B-32: Wakefield System per 2018 PHMSA Data[308]

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-70's Miles/Number	% of System
Mains	88.1	23.4	26.6%	24.1	27.4%
Services	5,033	835	16.7%	873	17.3%

There is a minor amount of Aldyl-A plastic in the system. There are 6 regulator stations feeding the main distribution system.

Wakefield reports it experienced no over-pressure events in the time period under review.

The system is fed from one interconnect with Tennessee Gas Pipeline (TGP) and three interconnects with National Grid. Typically, there is only one National Grid interconnect that is active at a time.

B.10.2 Field Visits of Construction and Maintenance Work (Execution)

The Panel visited 7 sites and observed construction and maintenance work including main installation, tie-in of service line and meter move out, as well as a locate and mark site. More details are provided in Appendix B.10.6.

B.10.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.10.6, the Panel observed the following, which was specifically related to Wakefield:

- Strengths:
  - Small team aids in communications among team members;
  - Adopt innovative approaches to address workforce availability and knowledge transfer concerns (Best Practice);
  - Conduct a tabletop emergency drill with local officials on September 26, 2019;
  - Active participation in industry associations to access broader perspectives and best practices from other companies (Best Practice);

[308] Mains or services that were reported as "unknown" vintage are considered in the pre-1970 cohort. Generally, when an operator reports the vintage as unknown it is due to a lack of a complete record on that asset. This suggests the asset was likely manufactured and installed prior to 1970 when Federal regulations requiring records were put into place.

  - Notification of municipal water departments before excavating to confirm water lines are marked; and
  - Positively confirm with excavator, following an 8-1-1 call, that the Gas Company has confirmed no gas lines are present in the area (Best Practice);[309]
- Opportunities:
  - Improve validation of information provided to the field and rely less on the tribal knowledge about asset location (which may be creating overconfidence and less reliance on records);
  - Conduct an RCA of the errors in locating and marking assets observed by the Panel. For example, the mis-mark of assets and the failure to mark existing service before excavating for new service;
  - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking, and the tendency to dismiss the need to look for errors or issues in similarly-situated circumstances;[310]
  - In cases where construction deviates from the construction plan, ensure that the records and physical abandonment is properly completed;
  - Develop and use site-specific procedures for critical tasks, including purges;
  - Ensure use of gauges on systems to measure pressure impacts on live mains during purges;
  - Make a habit of using appropriate PPE on work sites (while PPE was being used whether it was regular use was unclear); and
  - Increase care in managing the street at work site. Good street care indicates to the public the care undertaken by a construction crew and reflects respect for the community in which the construction is occurring. For example, a backhoe bucket on a mainline replacement project exceeded the width of saw cuts – creating uneven asphalt removal along entire trench line. The site was left overnight without filling in soil to match asphalt.

[309] As discussed in Section 10.1.9, positive contact between the Gas Company and the excavator has been adopted in Massachusetts by the DPU. See Final Order 19-43_10-4-19 (the Order) modifying 220 CMR 99.00, which adds a new provision requiring companies that receive notification of an excavation from the Dig Safe Center to affirmatively inform the excavator or otherwise indicate if they have no underground facilities within the safety zone.

[310] For example, when the third-party engineering drawings are found to be inaccurate at one project location, re-examine drawings for upcoming portions of the project to determine if other inaccuracies are present – instead of assuming that all other drawings are accurate.

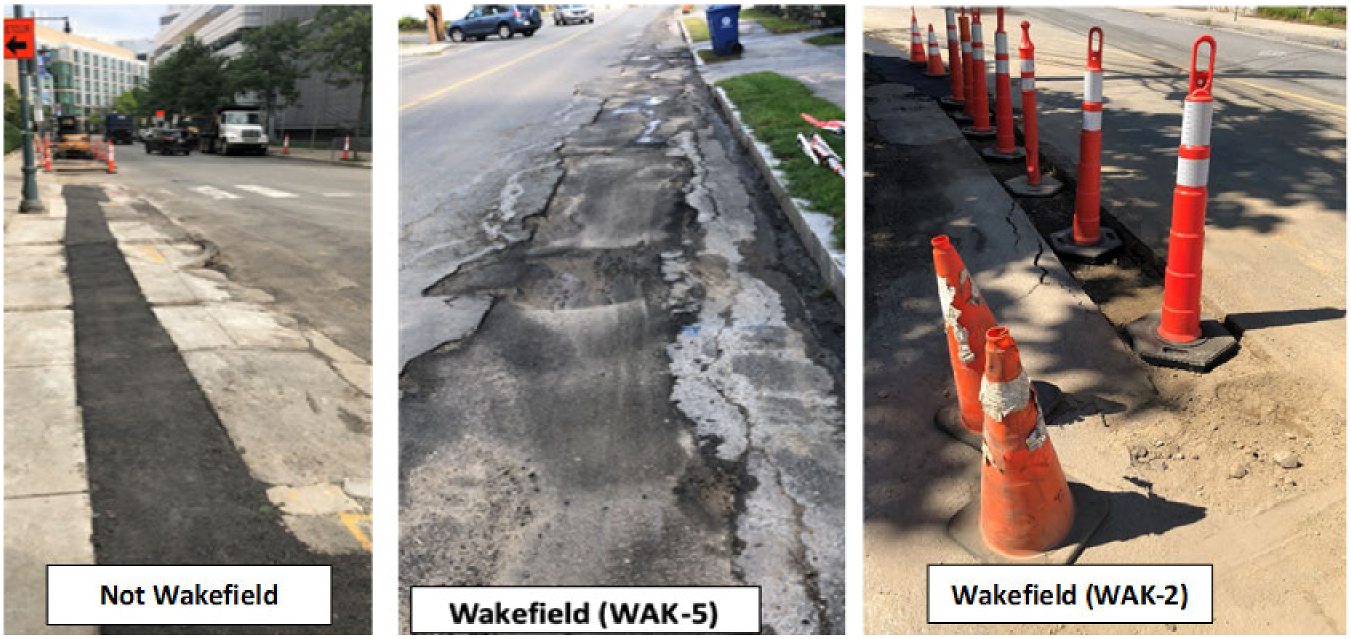


Figure B-13: **Wakefield**

The Panel observed several safety concerns during its field visit to Wakefield. These included:

- Failure to mark the location of the existing service line before excavating to install new line; and
- A mark and locate error on a mainline replacement project (in which an erroneous engineering drawing was being used by a contractor, despite the underlying record being accurate).

In addition, field personnel indicated during discussions with the Panel that pressure gauges were not used during purges. Although management later suggested personnel were confused during the discussion, the answers to some of the Panel's questions about purging practices, and about locating and marking services, suggested a basic lack of knowledge of certain operational issues. The confusion about the use of gauges during purging also serves as an example of why developing step-by-step procedures describing the appropriate sequence and steps for purging would be beneficial, especially for work not undertaken on a daily basis.

Contrary to being a learning organization that is open to feedback, however, management at Wakefield signaled that the Panel's observations were unlikely to result in internal reflection or change. For example, in discussing the mark and locate error in the engineering drawing, the Panel asked if Wakefield would undertake a review of other marks made based upon the engineering drawing with the error, and was told there was no need to do so. This approach contrasts with the basic tenets of becoming a learning organization in which asking questions is valued (i.e., *How did the error occur? Where else might there be an error? How can we be better? What are we missing?*).

As part of the Panel's obligations under the Guidelines for Engagement, the Panel asked Wakefield to call the DPU to report the Dig Safe violation. Wakefield did this on August 29, 2019. Based on management's response to the Panel's feedback, the Panel remains concerned about the apparent lack of recognition by management of the breadth and depth of the concerns that were raised.

Wakefield mentioned they were fined $40,000 by the DPU in a matter that arose 4-5 years ago and the matter remains pending with the DPU's Division of Pipeline Safety.

B.10.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Wakefield system is set forth in Table B-33, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-33: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Wakefield	75.18	4.07	56.82	4.57
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Wakefield's system and renewal programs based on this leak analysis are as follows:

- General trend for main leak ratio is downward. However, the ratio is comparatively high;
- General trend for services leak ratio is flat to increasing;
- The main reported cause of leaks for mains and services is corrosion, which is likely driven by the unprotected steel in the system (majority of leak prone mains and services);
- Continue the strong main renewal program and monitor; and
- Consider increasing the service renewal program to get ahead of general deterioration.

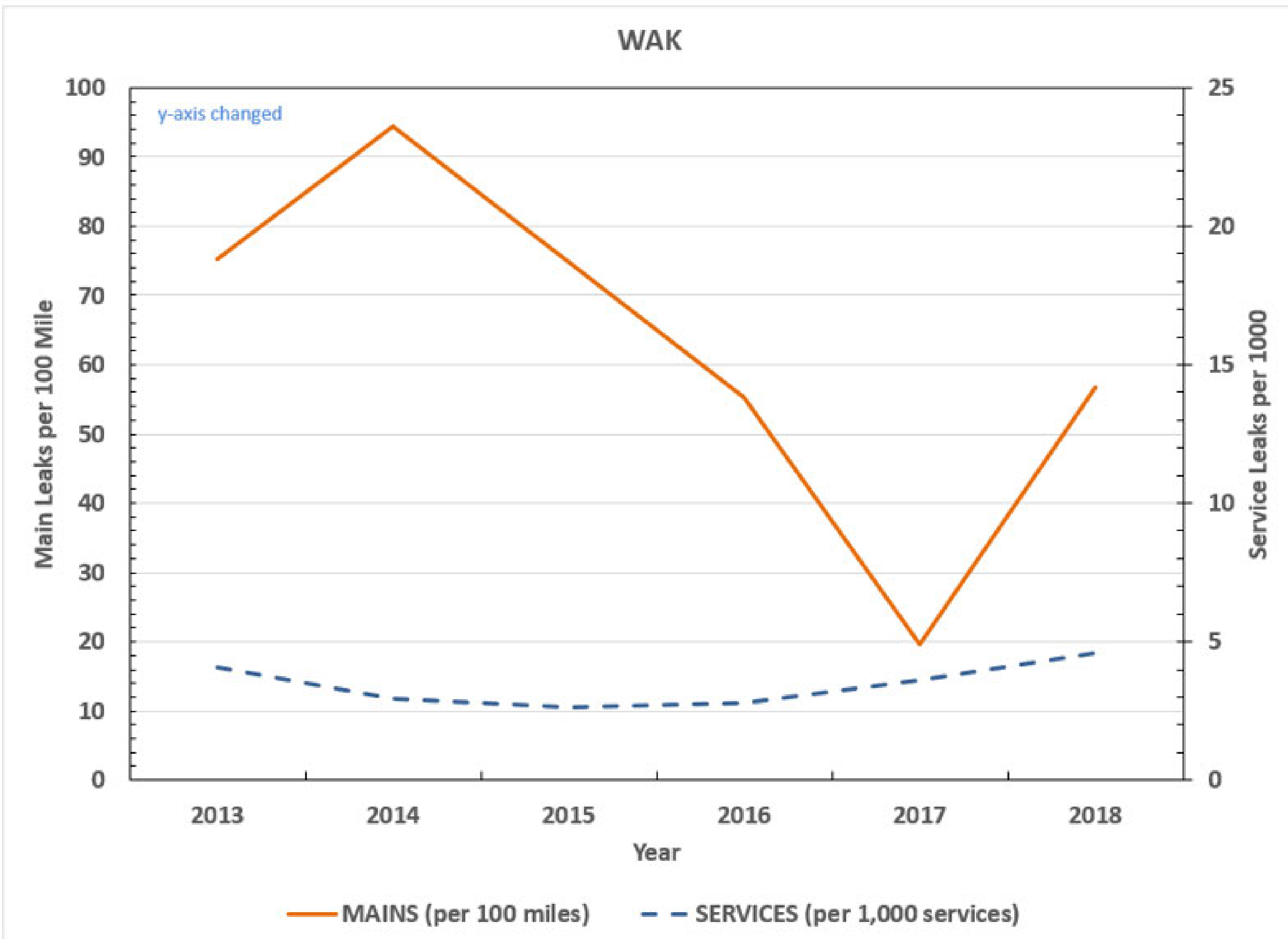


Figure B-14: **Wakefield Leak Ratio (Mains and Services)**

B.10.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. The *O&M Manual* is well organized and contains little detail. It is primarily code focused, with no deficiencies to minimum requirements noted;
    b. District regulator stations all have the same design and equipment, making operation and maintenance simple and straight forward;
    c. No drawings or diagrams of typical activities or installations. Consider adding for clarity;
    d. See records below under risk management. Consider a quality management program around records; and

e. Dig Safe Program is clear and requires taking pictures of marks, etc. Wakefield notifies water department (not a member of Dig Safe) to ensure water lines are marked. Also positively confirms with excavator if no gas or electric is present – this is a best practice. Consider clear expectations around miss locates, documenting communication with excavators, late locates, etc.

2. Construction Practices:
   a. Appear to follow minimum requirements with no noted deficiencies; and
   b. No references to written procedures, when used, who develops and executes, etc. Consider more robust and clear process for written procedures (both construction and O&M activities).
3. Distribution Integrity Management Program:
   a. DIMP appears to be regularly reviewed and updated;
   b. Threat identification is more SME driven but does include some external information. Consider moving to a more data driven program;
   c. Risk assessment is more SME driven. Consider moving to a more data driven program. Use of model but doesn't seem to drive decisions;
   d. Organizational responsibility for DIMP not documented;
   e. Linkage of risk mitigation plans to specific risk results is not clearly documented; and
   f. Consider including facilities in risk ranking.
4. Risk Management Program:
   a. Replacing cast iron and will start next on bare steel. Anticipate completion in about nine years;
   b. Does not consider risk holistically;
   c. Records are a key part of a robust risk management program. Began moving to GIS three years ago and believe it is now mature. Consider a quality management program around records; and
   d. Do not participate in industry trade groups – have SMEs they are comfortable with and use when needed. Consider more active participation in NGA to access broader perspectives and best practices.
5. Incident and Crisis Management:
   a. Lessons from Merrimack Valley – checked pressures at regulator stations; and
   b. Have run tabletops within organization but do not believe any were gas focused. Strong belief internally that their small size will allow them to handle an emergency. Consider regular tabletop and full-scale exercises that are gas focused. Include local first responders and local government officials.
6. Management Systems:
   a. Participating in NGA process.

B.10.6 Field Visit Summary

Table B-34: Field Visit Summary

Location No.	Description	Date	Photograph
WAK-1	Wakefield Office	9/29-30/19	
WAK-2	Main replacement per GSEP	9/29-30/19	
WAK-3	Prior Main Replacement	9/29-30/19	

Location No.	Description	Date	Photograph
WAK-4	Prior Main Replacement; mismarked sewer resulted in subsequently abandoned 80' of new main	9/29-30/19	
WAK-5	Service Replacement, mark and locate issue	9/29-30/19	
WAK-6	Take station, LNG Staging	9/29-30/19	
WAK-7	New Service	9/29-30/19	No Picture.
WAK-8	Gas Operations, Service Center, meeting with Management	9.30/19	No Picture.

B.11 Westfield Gas & Electric Light - WES

B.11.1 System Overview

Westfield Gas & Electric Light (Westfield) is a municipal system that serves Westfield in Massachusetts. As shown Table B-35, about 15% of mains and about 11% of services are leak prone pipe. About 22% of the mains and about 11% of the services are pre-code vintage.

Table B-35: Westfield System per 2018 PHMSA Data

	Total System Miles/Number	Leak Prone Miles/Number	% of System	Pre-1970s Miles/Number	% of System
Mains	211.7	32.5	15.4%	47.3	22.3%
Services	8,628	928	10.7%	906	10.5%

There are about 577 inside meter sets, all on the low-pressure system. Westfield reports no over-pressure events during the period under review.

The system is fed by a single source of supply from Tennessee Gas Pipeline (TGP), and it is basically the end of the pipeline. As such it faces gas potential safety risks related to supply shortages.

B.11.2 Field Visits Related to Construction and Maintenance Work (Execution)

The Panel visited 8 sites and observed construction and maintenance work including installation of new main as part of GSEP, installation of district regulator station, tie-in of new service line and meter move out, as well as a locate and mark sites. More details are provided in Appendix B.11.6.

B.11.3 General Observations

In addition to the general observations provided in Section 9 and the items discussed in Appendix B.11.6, the Panel observed the following, which was specifically related to Westfield:

- Strengths:
    - Stopped work after identifying fabrication in the opposite direction than depicted on the PE-stamped drawings and sought instruction from PE.
- Opportunities:
    - Ensure personnel at work sites are wearing appropriate PPE;
    - Improve excavation practices around live gas lines;
    - Consider the role of overconfidence as a barrier to becoming more of a learning organization. For example, the Panel observed in the field the belief that it was acceptable to do the work *the way it has always been done* rather than engaging in critical thinking, the tendency to dismiss the need to look for errors or issues in similarly-situated circumstances, and not accepting accountability for an individual's role (cite); and
    - Consider potential hazards when excavating along utility poles.

Westfield's management of the combined electric and gas company would benefit from more focus on gas safety practices and development of accountability structures.

Work sites and practices present many opportunities for improvement these include:

- Ban smoking on job sites;
- Require hard hats and steel toe boots for workers, contractors, and company supervisors;
- Keep worksite clear of hazards (trips, exposed nails, securing site appropriately at the end of the work day);
- Create appropriate egress from excavations (e.g., regulator pit installation);
- Improve traffic signage to provide adequate warning to drivers approaching worksite;
- Require spotter for backhoe operators while excavating;
- Consider location of utility poles adjacent to trench both when marking new trench;
- Seek input from portion of company in charge of electric services to obtain evaluation of the need for support for utility poles before excavating; and
- Institute company controls of the contractor behaviors on site.

The contractor provided misleading information when responding to the Panel's inquiries about if and when a job brief was held prior to work beginning and was not helpful in providing an understanding of what occurred.

The Panel observed several immediate safety hazards which it asked Westfield to take to the DPU as part of the Panel's obligation under the Guidelines for Engagement. These included:

- Dig Safe Violations (mechanical excavation up to and around live service lines and within the Company's tolerance zone);
- PPE (basic disregard for basic PPE requirements by contractor and company employees);
- Tailgate briefings (providing misleading information about job briefings when none occurred);
- Absence of work site leadership (in which neither the contractor nor company employees believed themselves to be responsible or accountable for safe excavations; and
- Excavating directly adjacent to utility poles without additional support, or consideration of the need for additional utility pole support, when excavating directly up to several adjacent utility poles.

Contrary to being a learning organization open to feedback, senior management at Westfield was quite defensive and generally signaled that the Panel's observations were unwelcome. Some of the discussion with the Panel about what PPE might be required on a job site and discussions about the excavation practices also suggested a basic lack of knowledge of certain construction execution issues.

During the discussion, the Panel learned Westfield had hired a third-party quality assurance company to conduct a safety culture review and received a 98% positive score for safety culture. Given the observations by the Panel, this safety culture assessment clearly provided management with a false sense that things are being done safely and in the way that the company's leadership thinks it is getting done.

Westfield sent a letter dated August 6, 2019, to the DPU reporting these deficiencies and the corrective actions they planned to take to address them. The Panel found the proposed corrective actions to be inadequate. Moreover, the Panel remains concerned about the apparent lack of recognition by management of the breadth and depth of the concerns that were raised. These observations provide opportunities for Westfield to increase its willingness to learn.

While Westfield is not covered by GSEP, if the pace of renewal over the last five years remains roughly the same in the future, Westfield would complete its replacement of leak prone pipe by 2039.

For companies with less than 100 miles of leak prone pipe remaining, including Westfield, replacement of leak prone pipe within a much shorter time (e.g., five years) could be feasible.[311] The Panel, however, does not recommend that Westfield increase its pace until it can satisfactorily demonstrate to the DPU or an independent third-party that it can safely execute projects.

The current pace of replacement is shown in Table 8 in Section 8.2.3.1 (see Table B-36 for relevant excerpt).

Table B-36: Excerpt from Table 8

Gas Company	PHMSA ID	Mains Leak Prone Difference 2013 to 2018	Services Leak Prone Difference 2013 to 2018	Projected Year of Main Replacement Completion (Based upon Current Pace)
WES	22511	19% reduction 40 to 32 (8)	36% reduction **1,454 to 928 (526)**	2039

B.11.4 Leak Analysis

A high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration. This ratio should be viewed as a trend over time since there are a number of variables that can impact the number of leaks discovered in any one year.

The leak ratio of the Westfield system is set forth in Table B-37, along with the comparisons to the average national leak ratio and the Representative Gas Company leak ratio.

Table B-37: Leak Ratios for Mains and Services (2013 and 2018)

Company	2013		2018	
	Main	Services	Main	Services
Westfield	23.69	1.32	19.38	4.06
Average National Ratio	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Observations about Westfield's system and renewal programs based on this leak analysis are as follows:

- General trend of main leak ratio is flat to downward, with a sharp increase over the last 2 years;
- General trend of service leak ratio is upward;

[311] This assumes appropriate support from all Stakeholders and availability of appropriately trained resources to execute the work safely.

- Both leak ratios are comparatively high;
- The main causes of leaks for mains and services are classified as other. Westfield reports that the increase in service leaks is due to incorrect installation of a fitting. Monitor leak ratio to ensure that is all that is driving this ratio upward; and
- Consider increasing cast iron renewal program to stay ahead of general system deterioration.

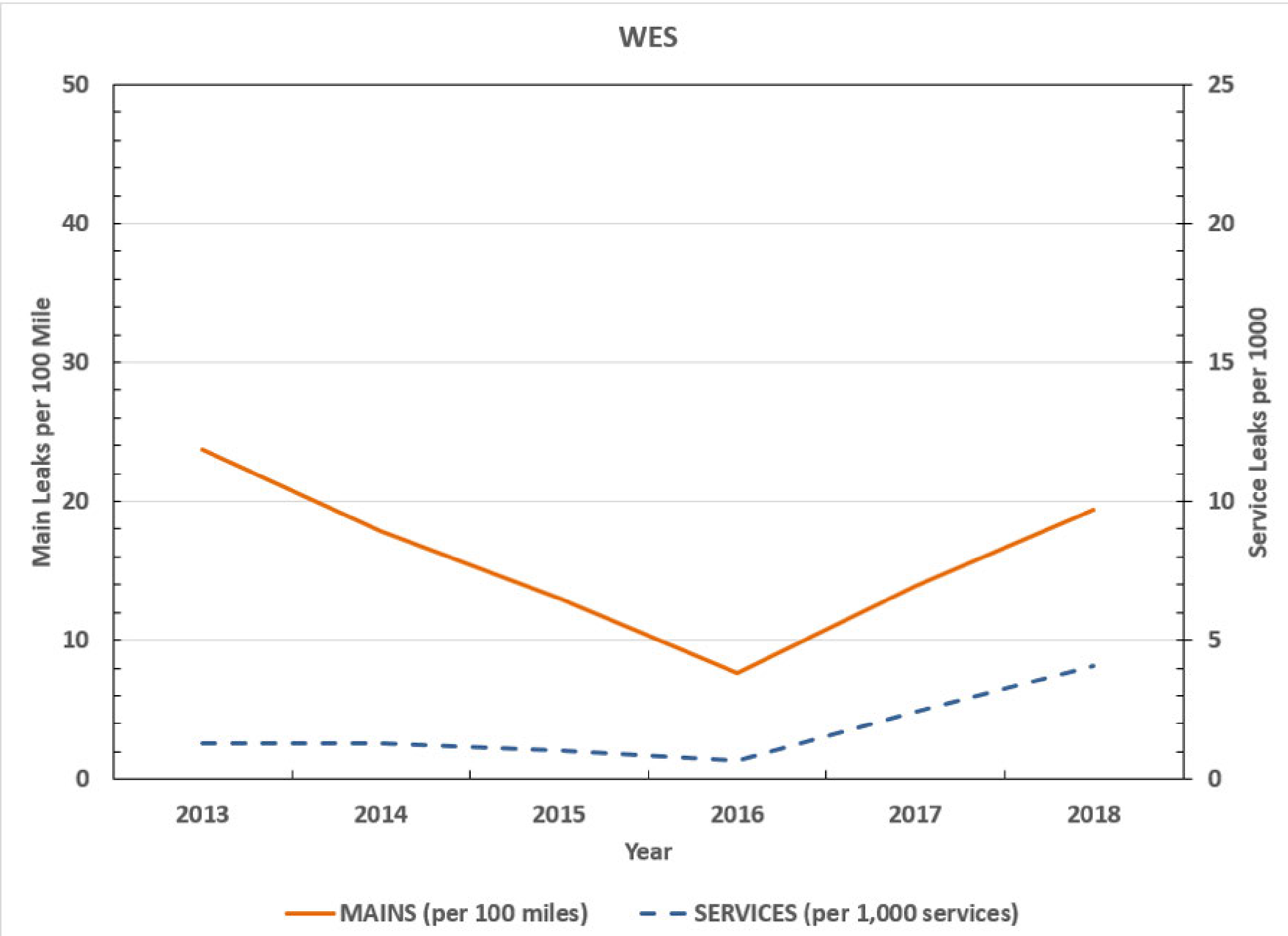


Figure B-15: Westfield Leak Ratio (Mains and Services)

B.11.5 Review of Written Procedures and Program

The Panel reviewed certain procedures and programs and highlighted the following observations:

1. Operations and Maintenance:
    a. The *O&M Manual* is organized and easy to use. It is short compared to other O&M manuals. It is primarily code focused, with no deficiencies to minimum requirements noted;
    b. Pressure testing appears to be beyond minimum requirements. Good practice;
    c. The *O&M Manual* does not include diagrams/drawings for common tasks and activities. Consider adding for clarity for team. Ensure higher risk activities are included;

   d. The *O&M Manual* mentions engineering work packets but it is not clear when or if written procedures are required for some activities. Consider adding requirement for certain activities, and clarify what is required, review, who executes and how, etc.; and
   e. See records below under risk management. Consider a quality management program around records.
2. Construction Practices:
   a. Appear to follow minimum requirements with no noted deficiencies; and
   b. Consider quality management program around construction practices.
3. Distribution Integrity Management Program:
   a. DIMP appears not to be actively managed and reviewed;
   b. Threat identification appears to be more SME driven;
   c. Calculated risk assessment using external model. It would appear SME input critical;
   d. Last revision appears to be in 2014. Some system information is not up to date in plan. Consider more frequent program review;
   e. Consider including facilities in risk ranking; and
   f. Linkage of risk mitigation plans to specific risk results no clearly documented.
4. Risk Management Program:
   a. Does not appear to view risk holistically;
   b. Money tends to drive many work decisions;
   c. Appear to be reactive to day to day issues rather than monitoring longer term system issues;
   d. Do not appear to use data to understand risks on system;
   e. Records are a key part of a robust risk management program. Consider a quality management program around records; and
   f. Appears to depend on DPU for compliance.
5. Incident and Crisis Management:
   a. No regular drills or exercises. Consider routine drills and exercises, including local first responders and government officials; and
   b. Lessons from Merrimack Valley – did look at sensing lines.
6. Management Systems:
   a. Will participate in NGA process.

B.11.6 Field Visit Summary

Table B-38: Field Visit Site Summary

Location No.	Description	Date	Photograph
WES-1	GSEP Main Replacement (4-inch)	7/31/19	
WES-2	Low-pressure regulator pit Installation; PE stamped drawings	7/31/19	
WES-3	New Service installation (HP)	7/31 /19	
WES-4	Contractor Facility (attempt to attend tailgate meeting)	8/1/19	No photograph taken
WES-5	Gas Operations Center; meeting with management	8/2/19	No photograph taken, meeting

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Appendix C Gas Company and Stakeholder Comments

This appendix contains comments from the Gas Companies and other organizations as part of the Snapshot Review Process, which the Panel undertook in early January 2020.

As part of that process, each Gas Company was provided with a copy of its Snapshot contained in Appendix B and a copy of Tables 1-10 contained in the body of this Final Report. The Panel also provided a summary of source data for the tables. Each Gas Company was asked to review their own Snapshot to identify factual errors that needed correction, if any. Each Gas Company was invited to discuss the draft Snapshot prior to it being finalized. Each was also offered the opportunity to provide up to two pages of comments on the contents of the Snapshots.

Additionally, the Panel provided a similar opportunity to certain organizations. Each was provided with those excerpts that were specifically relevant to each entity and were invited to review the excerpt, identify any errors, and to participate in a telephone conference with Panel to discuss those excerpts. This review opportunity was extended to the Massachusetts Department of Public Utilities, the AG Office, and the labor members of the Community Stakeholder Group. They were provided Section 10.1, Section 10.2, and Section 9.1.11, respectively. Each was offered the opportunity to provide up to two pages of comments about the contents of the Snapshots.

The comments generated by this Snapshot Review Process are contained herein.

C.1 Berkshire Gas Company

No commentary provided.

C.2 Blackstone Gas Company

Blackstone Gas Company

61 Main Street Blackstone, Ma.
01504

508-883-9516

January 15, 2020

To: **Patrick Vieth, Dynamic Risk**

From: Stephen R. Jolicoeur, Blackstone Gas Co.

Cc: Elizabeth Herdes

Cheryl Campbell

Re: **Statewide Assessment of Gas Pipeline Safety**

Commonwealth of Massachusetts

Review of Gas Company Snapshots

As you know, Blackstone Gas Company is under an Agreement to be sold to Liberty Utilities pending approval from the Department of Public Utilities. The tentative date of the sale is July 2020. We believe that this merger will benefit Blackstone's work force with additional resources.

During recent discussions with Liberty management, Blackstone has learned that the DIMP, O&M and Emergency Response Plan will be updated after the acquisition. In addition, there are plans to revamp and update the mapping and records systems.

Liberty is reviewing their options and or the possibilities of a second feed to the Blackstone's system, which will enhance our reliability.

There will also be upgrades to the automated meter reading system.

Blackstone employees will become associated with Liberty's Training and Operator Qualification programs.

Blackstone Gas Company has made a concerted effort to use PPE in all of its current daily operations.

The Dynamic Risk Statewide Assessment has brought to our attention our weaknesses and strengths. Going forward this assessment can only better our knowledge of our systems and strengthen our relationship with our customers.

Blackstone Gas Company would like to thank the Dynamic Risk staff for their honest observations and input throughout this process. Wishing you all the best.

Sincerely,

Stephen R. Jolicoeur

Stephen R. Jolicoeur

Senior V. Pres. of Operations

Blackstone Gas Company

C.3 Columbia Gas of Massachusetts

Columbia Gas of Massachusetts
A NiSource Company

Comments of Columbia Gas of Massachusetts

Columbia Gas of Massachusetts (CGM or the Company) appreciates the opportunity to address the Panel's observations relating to gas operations in the Company's Massachusetts service territory. CGM recognizes the importance of the Panel's work following the tragic over-pressurization in the Merrimack Valley in 2018 and is committed to the improvement of public safety as its highest priority. CGM greatly appreciates the opportunity to work constructively and frankly with the Panel as it conducted its work.

CGM also appreciates the Panel's observations of the Company's new, state-of-art training facility, talented crew leaders, and above and beyond Dig Safe compliance and inspector staffing. These aspects of CGM's operations are key to providing safe service to customers, as is the hard work and dedication of employees.

Some of the observations made by the Panel call for further improvement. CGM works hard to embrace continual learning and adaption and values this feedback. CGM has made a concerted effort since the Merrimack Valley event to learn from the incident and to fully institutionalize a higher-level focus on public safety. The Company has numerous efforts underway to address areas identified by the Panel, and the Panel's observations will strengthen those ongoing efforts. Primary areas of learning and ongoing improvement are as follows:

Safety Management System (SMS)
In the aftermath of the 2018 Merrimack Valley incident, NiSource accelerated the implementation of a comprehensive approach to managing safety across all of its operating companies, which is referred to as the Safety Management System (SMS). The SMS approach encourages critical thinking and continuous improvement of policies and procedures. SMS will provide CGM with an approach for rigorously identifying and managing risk, assuring the effective operation of key processes and promoting a learning environment.

The rollout of SMS represents not just a change in process at CGM, but a more holistic approach to enhancing the Company's safety culture. The SMS approach is intended to overcome any sentiment of complacency or resistance to change (in the field or elsewhere in the CGM organization), by encouraging employees at all levels to challenge the status quo and suggest improvements. All levels of employees (management through field employees) are trained to raise questions at any stage of a project when safety risks are identified, so that steps are taken to prevent harm from occurring. CGM has also established a Corrective Action Program that encourages all employees and contractors to identify any concerns with equipment, work methods, or issues regarding health and safety. CGM is realistic about the fact that these changes take time, but the ultimate result will be a heightened safety culture at every level.

Other Safety Improvements
Specific, safety-enhancing projects and commitments including the following:

- *LP Regulator Station Documentation:* CGM has completed locating, marking and mapping of control (regulator-sensing) lines at all low-pressure regulator runs on the CGM system.

- *Regulator Station Design/Over-Pressure Protection*: CGM initiated and completed an engineering design review of low-pressure regulator stations to determine how best to install additional over-pressure protection systems and other safety features. CGM has completed the installation of automatic pressure-control equipment on its low-pressure systems in Massachusetts. These devices operate like circuit-breakers. When the device senses operating pressure that is too high or too low, the device shuts down the flow of gas to the system, regardless of the cause. These devices operate independently of other pressure control devices and will automatically shut down the system to prevent over-pressurization.
- *Remote Monitoring*: CGM has committed to installing additional remote monitoring devices on its low-pressure systems to expand the ability of the gas control center to receive pressure alarms on a real-time basis. In the event a system is shut down by an automatic pressure control device (as described above), the remote monitors will enable quicker response times to restore service to customers. In 2020, the Company expects to complete the installation of these remote monitoring devices at all low-pressure stations.
- *Infrastructure Modernization*: CGM is continuing to modernize its system by replacing cast-iron and bare-steel pipes with more modern materials. The Company is currently ahead of its goal to have all cast-iron and bare-steel pipe replaced by 2034.
- *Professional Engineers*: Across CGM, all relevant construction documents and plans for construction work for complex projects are sealed by a professional engineer prior to commencing construction work, consistent with the recently-enacted Massachusetts statute.
- *Tie In and Tapping Procedures:* CGM has made critical enhancements to its tie-in and tapping procedures involving risk assessments; checklists for key stakeholder review of tie-in plans; contingency plans; identification/monitoring of impacted regulator stations; clear roles and responsibilities for tasks during the tie-in procedure; sign-off at each principal step of the tie-in procedure signifying completion; and documentation of pressure-gauge readings during the procedure. Initial training and implementation of these procedures is complete.
- *Capital Projects Review*: CGM has revised its procedure for stakeholder review of design capital projects, which will include an enhanced Constructability Review process to assist the project engineer with identifying the stakeholders required to participate in the review and to otherwise be consulted during project planning.
- *Management of Change*: CGM has supplemented its Management of Change (MOC) procedures to detail steps to enhance safety on construction projects, for example, during changes in company and contractor personnel.
- *Damage Prevention*: CGM has implemented enhanced damage prevention practices around low-pressure regulator stations, including field inspection and monitoring excavators working for third parties. When excavation work is being conducted in close proximity to regulator stations, a CGM employee will be present.

CGM has reviewed the Panel's observations in detail and is committed to incorporating this input into its efforts to learn, improve and reach a higher level of service to customers. The Company recognizes that an operating culture characterized by a commitment to continual learning and safety improvement, along with process and infrastructure changes to reinforce the safety of the system, will benefit customers and all other stakeholders over the long term.

Meggan Birmingham
Director, Safety Complaince & Risk Managemant – Columbia Gas of Massachusetts

C.4 Eversource Energy (NSTAR Gas Company)

EVERSOURCE
ENERGY

William J. Akley
President Gas Operations
107 Selden Street
Berlin, CT 06037
William.akley@eversource.com

Patrick Vieth
Executive Vice President
Dynamic Risk Assessment Systems, Inc.
Waterway Plaza Two, Suite 250
10001 Woodloch Forest Drive
The Woodlands, TX 77380

Re: Review of Gas Company Snapshots

Dear Patrick,

We are grateful for the work your team has performed as part of the Statewide Assessment of Gas Pipeline Safety for the Commonwealth of Massachusetts. Here at Eversource Energy, we live a commitment to "Safety First and Always," and so quickly took note of and appreciated your team's absolute and tireless focus on safety in both process and results.

This process—including the interactions and discussions throughout—has proven to be a valuable source of learning and continuous improvement for Eversource Energy. Further, our Gas Company Snapshot provides us with many good recommendations that we will follow up with action. We will also assess the results for other companies to determine additional opportunities for learning and improvement, e.g., by reviewing best practices identified at other companies. Finally, we will use our noted areas of strength to recognize our employees who have worked to further those practices and our overall commitment to safety.

As per our follow up conference call, Eversource Energy is committed to an accelerated replacement program that achieves the target 20-year timeline. We are proud of the results of our program to date, which has significantly reduced leak rates in our system, as noted in our Gas Company Snapshot.

In conclusion, we believe this effort has already begun to benefit Eversource Energy, its customers, and the Commonwealth. We appreciate the opportunity to participate, and we look forward to the next phase of the Assessment.

Sincerely,

C.5 Holyoke Gas & Electric

Commissioners:
Francis J. Hoey, III
Robert H. Griffin
James A. Sutter
Manager:
James M. Lavelle

EMPOWERING YOUR WORLD

To: Patrick Veith, Dynamic Rick

From: Brian Roy, Holyoke Gas & Electric

Date: January 16, 2020

Subject: Statewide Assessment of Gas Pipeline Safety – Holyoke Snapshot Corrections

CC: James M. Lavelle, HG&E; Cheryl Campbell, Dynamic Risk; Elizabeth Herdes, Dynamic Risk

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In response to the communication received on January 2, 2020, regarding the "Review of Gas Company Snapshots", Holyoke Gas & Electric hereby submits its comments in response to the observations presented.

Observations:

- Holyoke eliminated its only section of cast iron gas main to operate at elevated pressure in 2019. Cast iron gas mains are now only on the low-pressure distribution system.
- Acceleration of asset replacement is currently limited by available resources (recognized by note 270 on page B-49). While financing may be obtained through bonding or reserved via capital planning, required qualified labor resources are limited. Even at the current pace of replacements, resources are not sufficient at times to meet needs. If acceleration is mandated, the qualified workforce will still be limited for years until adequate experience is gained. Additionally, in-house labor needs will increase. For example, for Holyoke to begin a 5-year accelerated leak prone main replacement plan, the in-house workforce would need to be doubled at a minimum just to have adequate resources for managing, planning, inspecting and properly recording as-built and as-found information. This does not take into account the availability of required outside contractors that would need to be qualified and readily available.
- Following up on recommendations provided by Dynamic Risk, Holyoke conducted an emergency drill in 2019 and is planning to participate in a second drill during Q1 2020.

C.6 Liberty Utilities (New England Natural Gas Company)

Liberty Utilities (New England Natural Gas Company) Corp. ("Liberty" or the "Company") appreciates Dynamic Risk's diligence throughout this process and the constructive feedback it provided in the company-specific Snapshot. The Company is taking action on the opportunities identified therein and looks forward to working with the Department of Public Utilities ("Department"), the Department's Pipeline Safety Division, the Massachusetts' Office of the Attorney General and affected stakeholders to implement Dynamic Risk's recommendations, while continuing to provide safe and reliable service to our customers.

C.7 Middleborough Gas & Electric

No commentary provided.

C.8 National Grid

Statewide Assessment of Gas Pipeline Safety

Comments of National Grid

January 15, 2020

In November 2018, the Massachusetts Department of Public Utilities selected and contracted with Dynamic Risk Systems, Inc ("DRA") to conduct an independent statewide examination of the safety of the Commonwealth's natural gas distribution system and DRA assembled an independent review panel (the "Panel") to conduct the examination. On January 2nd, National Grid received a snapshot of the Panel's observation of National Grid based on their assessment. We appreciate the opportunity to provide our perspective on the observations of the Panel and look forward to a continued dialogue with all interested stakeholders with regard to pipeline safety.

National Grid operates the second oldest gas distribution company in the country. Of National Grid's approximately 11,000 miles of gas main, over 3,000 miles or roughly 28 percent is cast iron and bare steel, which is more susceptible to leaks. Recent gas incidents in the region reinforce the need for constant vigilance and improvement in the area of gas safety, and National Grid is committed to taking a leadership position on this issue.

National Grid appreciates that the Panel recognized many of National Grid's strengths when it comes to pipeline safety including its observation that National Grid is a learning organization. As part of National Grid's commitment to continuous improvement on pipeline safety, in 2017 National Grid voluntarily adopted the American Petroleum institute's ("API") Recommended Practice 1173, which provides guidance to pipeline operators for developing and maintaining a pipeline safety management system and is a best practice. One of the important elements of a pipeline safety management system is to capture learnings from events such as those in the Merrimack Valley. After that incident, National Grid immediately reviewed a number of issues that were highlighted, and all of the recommendations highlighted to NiSource by the National Transportation Safety Board have either already been or are in the process of being incorporated into National Grid's pipeline safety improvement plans as part of our adoption of API 1173.

Notwithstanding the considerable number of strengths observed by the Panel, a number of opportunities for improvement were also observed. National Grid has begun its review of those opportunities and looks forward to developing action plans where needed to incorporate into our safety improvement plans. While further review will be required to fully address each of the observed opportunities some initial feedback on certain of the Panel's observations is provided below.

First, with regard to the Panel's observations around tracking critical gas events, National Grid has established a formal process for reporting and evaluating pipeline safety incidents with increasing levels of investigation and root cause analysis applied based upon the level of risk associated with the incident. Once root causes have been identified, corrective actions are developed to minimize the likelihood of the same or a similar pipeline safety incident occurring again. These corrective actions are tracked to completion, and assurance activities are conducted to ensure that these actions become business as usual. In particular, National Grid tracks and reports every exceedance of Maximum Allowable Operating Pressure in Gas Control (for both high- and low-pressure systems) and where it is found to be material conducts an incident analysis as described above. Considering the Panel's observations, the Company will undertake a review of its procedures to determine whether communication surrounding these events across the organization, including any lessons learned, can be improved upon.

Second, with regards to the Panel's observation to consider whether extensive standard operating procedures ("SOP") are adding sufficient benefit at less complex jobs, the Company has a long standing and accepted practice that SOPs are required on all work that interrupts the flow of gas regardless of the complexity of the job. We believe that reducing the standard would open the process up to confusion and would not be beneficial to maintaining safe work practices.

Third, the Company agrees with the Panel's observation regarding the benefits of increased use of independent inspectors. The appropriate ratio, whether it be 1:1 or 1:2 as suggested by the Panel or some other number, will need to be determined based upon the type of work, the proximity of the work locations to residential and commercial development (based on the density of the service area in which the work is being performed).

Fourth, the Company recognizes that there are opportunities around quality management of distribution records and notes that it has undertaken a comprehensive review of its gas management systems known as Gas Business Enablement, which includes, among other things, consolidating and updating existing GIS applications and developing future capability for electronic as-built creation in the field with validation by the Company's Maps and Records team.

Fifth, with regards to the Panel's observations around barriers to construction and the overall pace of pipeline replacement, the Company acknowledges and has recognized these challenges in its annual Gas System Enhancement Plan ("GSEP") filings. The GSEP is the Company's program to replace leak prone gas pipe ("LPP"). National Grid has identified certain milestones that it expects to achieve with regards to main replacement, both in relation to the miles of main and number of proactive services replaced. However, the Company's ability to achieve the identified milestones has been, and will continue to be, affected by several factors some of which are outside of its control. These factors include: weather conditions; high concentration of LPP in certain cities and towns; the level of cooperation shown by municipalities in which projects take place and associated municipal replacement projects and priorities; the availability of cost-effective labor to perform the replacements; availability of police details; the cost and availability of raw materials; prevailing conditions in capital markets; and the general business environment in which the Company operates. Moreover, infrastructure replacement activities are becoming more complex as the Company concentrates its efforts in more urban areas, such as the City of Boston and the City of Lowell. The Company will continue to monitor and evaluate ways to mitigate these barriers.

Finally, National Grid acknowledges the observations around its O&M procedures and will conduct a process review in light of the Panel's assessment to determine improvements.

C.9 Unitil (Fitchburg Gas and Electric Light Company)

January 15, 2020

Mr. Patrick Vieth
Dynamic Risk Assessment Systems, Inc.
Waterway Plaza Two, Suite 250
10001 Woodloch Forest Drive
The Woodlands, Texas 77380

Re: Company Perspective on the Safety Assessment Observations

Dear Mr. Vieth:

On behalf of Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil" or the "Company"), please accept this letter as Unitil's response to Dynamic Risk's January 2, 2020 invitation to share our perspective on the observations highlighted in the "Snapshot" section of the Safety Assessment Observations. As an initial matter, I want to thank Dynamic Risk for its professionalism and straight-forward approach throughout the process, which we believe has resulted in a wide-ranging and comprehensive analysis. Unitil has a deep commitment to public safety. We take great pride in our safety record, continually strive to improve our safety programs and training, and work hard at cultivating an exceptional safety culture. We appreciate the assessment team recognizing our robust DIMP program, over-pressure protection and leak management approach as best practices, and we are commited to addressing each of the identified additional opportunities for improvement and refinement. In fact, even before this Snapshot was issued, the Company had already implemented corrective measures to specific observations that were identified and communicated during the field assessment.

During the the Phase 2 field visits the assessment team identified a few observations that have already been acted upon. These include the following:

1. An Operator Qualification ("OQ") Task Review associated with service upgrades. As a result of this review the plumber no longer plugs and caps abandoned services at the basement wall. These activites are now being performed by the construction crew.

Christopher J. LeBlanc
Vice President, Gas Operations
leblanc@unitil.com

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2. The Company has procured and distributed 24” expander plug tools to all crews to ensure the expander plug is installed outside of the foundation wall.

3. Reviewed Unitil PPE requirments with all contractors, including plumbers perfroming work on non-jurisdictional facilities. Company inspectors are ensuring all contractors follow these requirements.

With the other opportunites identified in the Snapshot, the Company plans on establishing review teams to analyze and address each of these issues.

I again wish to emphasize the Company’s commitment to public safety, including the implementation of construction and maintenance programs with an emphasis on safety and continuous improvement.

Sincerely,

Christopher J. LeBlanc
Vice President, Gas Operations
Unitil Service Corp.

Christopher J. LeBlanc
Vice President, Gas Operations
leblanc@unitil.com

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C.10 Wakefield Municipal Gas & Light

Comments from Wakefield Municipal Gas and Light Department
Review of Gas Company Snapshot

Wakefield Municipal Gas and Light would like to thank Dynamic Risk for the time and effort that you put into this report. Wakefield has reviewed all strengths and opportunities discussed and agrees that there some areas of our work that need improvement immediately and other items that we can work over a longer period of time. We have been proactive in our own measures in a variety of ways. We are continually working to improve our reliance on records rather than tribal knowledge. As seen during the site visit, we use tablets to access all of our company records from any location. We have done additional trainings on this technology since your visit here and have seen more reliance over time. As with anything, change takes time but with our current staff, adoption has been smoother than expected. We are continuing to look at accelerating our replacement of leak prone bare steel and 2019 was our highest annual replacement total ever. We were also able to get our Level 2 leaks under 10 and Level 3 leaks down by 15% with a goal this year to have no Level 2 leaks at year end and have all Level 3 leaks above 50% to be eliminated. We are also looking to improve as a learning organization which something that will evolve over time but this work and or PSMS work is helping with this.

With regards to marking and locating, the following has been implemented to improve our focus on DigSafe.

- New Locating equipment purchased
- Training on locating practices, procedures and equipment
- Review of recent Dig Safe changes by the DPU
    - Changes with GIS / records process to support these requirements
- Substantial improvements have been made with WMGLD records access to support the dig safe process in the field
    - Enhanced information for field personnel via tablets
    - Additional training on the use of tablets when accessing information
- A Check list was created to provide focus for dig safe personnel

Our locators will be provided additional trainings to improve the quality of our locates. Over time, our prediction and hope is that with all of these additional measures, we will see continued improvements.

We are reviewing other opportunities mentioned in the report but just wanted to confirm our responsive actions thus far.

Peter Dion
General Manager
Wakefield Municipal Gas and Light

C.11 Westfield Gas & Electric Light

Commentary on:
Dynamic Risk - Statewide Assessment of Gas Pipeline Safety – Commonwealth of Massachusetts
Review of Gas Company Snapshots

Provided by Michael Lee – Westfield Gas + Electric
January 15, 2020

The Management of Westfield Gas + Electric has reviewed the Company Snapshot prepared by Dynamic Risk and is providing this commentary ahead of the Panel's final report.

B.11.3 - General Observations

Concerns were raised about WG+E's excavation practices. Westfield Gas + Electric has historically used the industry-approved pot-holing method as a means of locating facilities within the 18" safety zone. This process is currently under review by the MA Department of Public Utilities. We recognize that during the inspection, the process was not properly executed, and we have reinforced the need for a spotter when using mechanical means as well as seek other utilities' requirements for excavating around their facilities. Additionally, we are working to improve overall jobsite hazard mitigation.

Westfield Gas + Electric acknowledges the deficiencies in our tailboard jobsite briefing practice. Immediately following the field visits by Dynamic Risk, we implemented a new procedure and form for tailboard use. This form closes several gaps, including responsibility and accountability, minimum PPE, and work-zone safety, including traffic signs and barricades. We intend to meet with our third-party safety inspector ahead of the 2020 construction season to review our safety procedures and policies to ensure valid inspections. Additionally, WG+E has elected to increase in-field supervision for both safety and operational oversight. Also, we have implemented job-specific written procedures that require the approval of two supervisors, at a minimum, as well as on-site supervision of all main tie-ins and cut-offs, and three-part communication through the control room operator.

B.11.5 - Review of Written Procedures and Program

The Panel's review of the WG+E's O&M was primarily positive, with suggestion to expand on the library of drawings for common tasks. This recommendation will be adopted into the next O&M revisions.

Following the assessment, we did a thorough analysis of our DIMP model. We found that some of the weighting criteria did not accurately assess the risk in our system. We made the appropriate adjustments which now give the greatest consideration to leak prone pipe. Management has made the decision to not only eliminate leak prone pipe but to eliminate all low-pressure systems as well. Engineering and capital plans have been put in place to systematically remove the risk prone pipe and systems. Resources are in place to accomplish this within approximately 10 years while maintaining that all safety measures are in place and adhered to.

We acknowledge the importance of practical gas-related emergency drills. As such, we designed our 2019 annual disaster recovery table-top drill to include police, fire, dispatch, ambulance, DPU, and a local emergency planning committee representative. This event was led by our Business Continuity consultant and was coordinated with the three other municipal gas departments in the State. The event involved an over-pressurization event similar to what occurred in Merrimack Valley. We intend to expound upon this by organizing a field drill in the coming months.

Westfield Gas + Electric is actively working with the Northeast Gas Association and its consultant, Blacksmith Group, to develop a Safety Management System following the API RP1173 standard. This system will include a gap analysis specific for our organization as well as a Management of Change process. Through this process we wish to enhance our quality management efforts and programs for both records and construction practices to further address the concerns of the panel.

We appreciate the opportunity to speak to the concerns raised by the Panel. Westfield Gas + Electric also looks forward to working with the DPU and other operators to collaborate and adopt best practices that have been identified. While many opportunities raised by Dynamic Risk have been addressed, WG+E recognizes that the natural gas industry needs to continually improve to truly develop a safe and reliable product for the community. Moving forward, WG+E will remain transparent in its activities and procedures and welcomes open collaboration, particularly with the DPU and other outside stakeholders.

C.12 Massachusetts Department of Public Utilities

Public safety is the Department of Public Utilities' ("DPU's") top priority. DPU is the state agency delegated authority for pipeline safety by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA"). While DPU has consistently met federal standards, DPU's goal is to exceed those standards, ensuring that the Commonwealth's natural gas distribution system is as safe as possible.

DPU commissioned this report to secure an independent evaluation that examined the physical integrity and safety of the natural gas distribution system and the operation and maintenance policies and practices of all natural gas distribution companies operating within the Commonwealth. The independent evaluator has achieved that goal and provided valuable recommendations for all stakeholders, including DPU.

As described in more detail below, the phased nature of the reports has allowed DPU to already begin addressing the recommendations found in the final report. As the final report acknowledges, DPU has taken substantial action to improve pipeline safety since the first phase of the report issued last year. More specifically, DPU has dramatically increased staffing levels, expanded the Gas System Enhancement Plan ("GSEP"), promulgated multiple regulations, increased penalties for Dig Safe violators, and participated in numerous gas company emergency response drills. The final report identified some additional steps DPU could take to even further improve pipeline safety. As outlined below, DPU will integrate those recommendations into the policy and management practices that DPU has already implemented.

Staffing and Organizational Structure (10.1.1-10.1.6, 10.1.8, 10.1.10)

To expand DPU's oversight and as a result of our increased funding, DPU has been able to nearly triple the size of our pipeline safety division, making it DPU's largest division. DPU now has three times more public utility engineers ("PUEs") than it had in September 2018. This increased staffing will allow DPU to exceed PHMSA requirements and focus resources on areas that DPU believes require increased attention. While the report correctly notes that DPU meets all requirements of PHMSA's oversight program, our additional funding has enabled the pipeline safety division to take a broader look at pipeline safety than PHMSA requires through inspections.

DPU has also hired a new pipeline safety director and added additional positions to support the director's work, including an assistant director and an assistant general counsel. To improve efficiency and effectiveness, the new director has already started to change the approach to the geographical areas and gas companies that DPU oversees. DPU has hired PUEs located throughout Massachusetts and has stressed the importance of individual accountability and ownership for assigned areas of inspection. While DPU will ensure that it has appropriate oversight of each gas company, DPU will continue to dispatch resources to areas of greatest need or concern.

The new director is also in the process of establishing internal timelines to expedite the processing of enforcement actions. The improved timelines will allow DPU more flexibility when determining the most appropriate outcome for a particular incident. For example, if DPU finds a pattern of violations associated with a specific task, and the violations appear to be because of a lack of knowledge and not indifference or negligence, DPU may explore a resolution that is more educational in nature and less punitive. Conversely, if DPU has recommended learning opportunities or finds a pattern of deliberate or reckless activity, DPU will aggressively pursue the offenders and seek significant penalties to deter future behavior.

Record Keeping (10.1.7)

To improve record keeping, in addition to the new support staff, the pipeline safety director has reached out to pipeline safety programs in other states to discuss best practices and the data-management programs they have found effective. DPU will soon issue an RFP for data-management software to improve data tracking, data reporting, and recordkeeping. Additionally, DPU now posts on its website documents related to pipeline safety investigations.

DPU Targeting Repeat Offenders Under Dig Safe (10.1.9)

To reduce damage to gas pipelines by excavators, DPU issued regulations that significantly increased fines for Dig Safe violations related to gas pipeline infrastructure. Previously, the maximum initial fine that a company could face was $1,000 and repeat offenders could not be fined more than $10,000 per violation. Because these fines could be less than the cost of stopping work, some companies would risk the fine rather follow the Dig Safe requirements. The new regulations implemented a maximum fine of $200,000. With this considerably increased fine amount, Dig Safe violators face serious punishment that exceeds the cost of stopping work. Additionally, Governor Baker included in his FY2021 budget proposal sections that would remove municipal exemptions and increase Dig Safe fines for violations related to all types of infrastructure, not just gas pipelines. DPU has also listed persistent Dig Safe violators on its website, and DPU is coordinating with the Division of Professional Licensure ("DPL") to ensure information about Dig Safe violations is readily available to DPL.

DPU Action to Improve the Gas Safety Enhancement Program (10.1.11)

To reduce gas leaks, DPU made several significant changes to GSEP. DPU has expanded the scope of GSEP, allowing for the accelerated replacement of a potentially leak-prone, first generation plastic pipe, known as "Adyl-A" pipe. In addition, a DPU order doubled the amount of work the gas companies can include in their GSEP. Further, Governor Baker included in his FY2021 budget proposal sections that would require gas companies to focus GSEP plans on reducing leak rates and set interim targets for replacement work conducted under GSEP. DPU has also issued new gas leak regulations that set increased standards for the repair of gas leaks. These new regulations, for the first time, recognize the importance of repairing environmentally significant grade three leaks.

Additional Actions by DPU

In addition to the actions outlined above, DPU has implemented two previous recommendations regarding pipeline safety. First, as outlined by the National Transportation Safety Board's report regarding the use of professional engineers, DPU has implemented the Commonwealth's new professional engineer law. The statute requires all natural gas work that could pose a material risk to public safety be reviewed and approved by a certified professional engineer. All natural gas engineering plans and specifications must now bear the stamp of approval of a certified professional engineer when that work could pose a material risk to public safety, as determined by DPU.

Second, as identified by the first phase of the independent report, DPU has improved emergency response planning. DPU has conducted or participated in eleven emergency response drills exclusively with gas distribution companies throughout the state. DPU coordinated with MEMA prior to the design and implementation of the drills and will work with MEMA to conduct gas specific drills. DPU has also hired PUEs with experience conducting and developing emergency response exercises. Additionally, Governor Baker included in his FY2021 budget proposal sections that would increase the potential fines for violations related to a company's emergency response and the Massachusetts pipeline safety code. This legislation would set fine amounts at levels that are more appropriate for significant violations.

Conclusion

DPU believes that this report and its recommendations are a valuable tool for all stakeholders in the natural gas distribution system to improve public safety, DPU's top priority. DPU will continue to improve pipeline safety and will continue to take action to address the areas for improvement that the final report has identified. We look forward to working together with all stakeholders to ensure the highest degree of pipeline safety in the Commonwealth.

C.13 Massachusetts Office of the Attorney General

<u>Dynamic Risk Draft Final Report Excerpts</u>
<u>Office of the Massachusetts Attorney General's Comments</u>

On January 2, 2020, Dynamic Risk provided the Massachusetts Office of the Attorney General ("AGO") with a draft copy of Section 10.2 of Dynamic Risk's draft Final Report (the "Excerpts"). Because the AGO has not yet had the opportunity to review the entirety of the Final Report, it limits its comments to the Excerpts.

The Attorney General's Role as Ratepayer Advocate.
After public outcry over high electric and gas rates during the 1970s energy crisis, the Massachusetts Legislature established the Office of Ratepayer Advocacy within the AGO to serve an invaluable role in the Commonwealth's regulatory compact whereby for-profit utilities are granted a monopoly to provide service in defined territories in exchange for being regulated by the Department of Public Utilities ("DPU").[1] The DPU, rather than the competitive market, determines utilities' profit margins. Among other duties, the Legislature charged the AGO with advocating for and protecting the interest of utility customers. As the only Massachusetts state entity with this responsibility, the AGO is essential to ensuring that utility customers receive reliable and safe service at the lowest possible cost. One way the AGO carries out this role is by intervening in regulatory cases at the DPU in matters that affect the safety and quality of utility service and how much consumers pay for that service. In cases involving utilities that provide gas service, the AGO, as the independent legal representative for ratepayers, advocates for customers' interests through the regulatory process. For example, in a rate case, where a gas utility petitions the DPU for an increase in customer rates for services that the utility provides, the AGO asks the utility questions about the utility's petition, cross examines the utility's witnesses, and often presents its own expert witnesses. This process ensures that the DPU has all the relevant information that it needs to make an informed decision rather than relying on information solely provided by the interested utility. Thus, the AGO serves as a vital check on a utility's ability to undertake action that may run counter to the interests of ratepayers, and ensures that customers' interests remain central to the regulatory analysis. Similarly, the AGO's participation in and utilization of this process promotes transparency and is essential to preserving the integrity of the process.

The Excerpts imply that gas utilities are overly burdened by having to address customers' interests as advanced by the AGO in administrative litigation before the DPU.[2] But this is precisely the promise—and obligation—of the regulatory compact; it is the statutorily-mandated role of the consumer advocate in Massachusetts to protect the interests of consumers. Indeed, utilities across the country know that answering a consumer advocate's questions or responding to issues raised by a consumer advocate is a routine and critically important part of the regulatory process—without the participation of consumer advocates, consumers would be left without expert representation in cases that involve multiple, complex technical matters governed by often arcane legal and procedural norms.

The Excerpts also assert that there is a "perception" that the AGO's arguments or positions in these cases "deserve additional weight and deference"[3] and that the presence of a criminal bureau in the AGO may contribute to this "perception."[4] The DPU, as the decisionmaker, weighs the evidence presented by all parties in a case and determines case outcomes as it sees appropriate. The Excerpts point to no instance in which the DPU gave

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[1] G.L. c. 12, § 11E.
[2] In gas-related cases, other parties besides the utility companies do not usually answer AGO questions or respond to AGO arguments. For instance, in the most recent gas system enhancement program and gas rate case matters the gas companies are the only entities that consistently responded to the AGO's arguments.
[3] Excerpts, Section 10.2.3, at 77.
[4] Excerpts, Section 10.2.3, at 77 n.197.

improper deference to the AGO or where the AGO has failed to advance pipeline safety. In fact, the record demonstrates that the AGO consistently has been a strong proponent of pipeline safety.[5]

Of course, regardless whether a state's consumer advocate is housed in the AGO or within an independent state entity, a utility that has committed a criminal violation of the law, like any corporation, may be subject to criminal prosecution.[6]

Pipeline Safety Expert on the AGO Team.[7]

The AGO agrees that it would be helpful for the AGO's Office of Ratepayer Advocacy to include a full-time pipeline safety analyst or engineer on staff.[8] This would require a new analyst FTE position and the funding to support that position.[9]

Balancing Costs and Safety.

The Excerpts state that meeting the AGO's role of advocating for safe and reliable service at the lowest cost possible "requires balancing the innate tension between costs and safety."[10] The AGO notes that it has never opposed expenditures necessary for safety nor do the Excerpts cite to any instance where a gas company was not able to make a prudent safety investment because of the AGO. Rather, the Excerpts only cite to instances where the AGO supported safety expenditures.[11] To the extent that the Final Report advocates for accelerating pipeline replacement, the AGO urges Dynamic Risk to stress that any replacement acceleration should not take place until the gas companies demonstrably achieve the necessary safety improvements.[12] As the Merrimack Valley tragedy demonstrates, unsafe operations during pipeline replacement activities can have enormous and deadly consequences.

Costs Outside Gas Companies' Control.

The AGO does not have authority over the costs that municipalities charge gas utilities.[13]

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[5] *See* Excerpts, Section 10.2.1, at 76 n.194 (citing instances where the AGO has supported gas utility proposals). Similarly, as indicated in the AGO's Phase I Summary Report Comments dated May 31, 2019, the AGO has consistently raised safety concerns and advocates for accountability when gas companies endanger public safety.

[6] For example, federal prosecutors brought criminal charges against Pacific Gas and Electric ("PG&E") after the 2010 San Bruno pipeline explosions. *See* Case No. CR-14-00175, U.S.D.C. Northern District of California; Thomas Fuller, *California Utility Found Guilty of Violations in 2010 Gas Explosion That Killed 8*, New York Times (Online) (published August 9, 2016). Prosecutors declined to charge PG&E after 2017 wildfires. Alene Tchekmedyian, *No Criminal Charges for PG&E in 2017 Northern California Wildfires, Prosecutors Say*, Los Angeles Times (Online) (published March 12, 2019). Butte County prosecutors are also investigating PG&E as a result of last year's deadly Camp Fire. J.D. Morris, *FBI to Test PG&E Equipment in Camp Fire Criminal Investigation*, San Francisco Chronicle (Online) (published April 18, 2019).

[7] Contrary to the assertion in the Excerpts, from 2014 to 2019, the AGO's ratepayer advocacy team included a pipeline safety expert who was also an attorney that previously worked at the DPU in the Pipeline Safety Division where he conducted pipeline safety enforcement actions and investigated gas pipeline incidents, among other things. Given his extensive pipeline experience, while at the AGO, this attorney played a critical role on a number of gas-related DPU matters including, but not limited to, rate cases, forecast and supply plans, and all Gas System Enhancement Program dockets. He also worked on gas safety and gas company related legislation. On January 10, 2020, the AGO notified Dynamic Risk of this error in the Excerpts.

[8] *See* Excerpts, Section 10.2.1, at 76.

[9] In addition to in-house experts, the AGO has the statutory authority to hire outside experts to assist the AGO in matters before the Department, including gas-related matters. G.L. c. 12, sec. 11E.

[10] Excerpts, Section 10.2.1, at 76.

[11] Excerpts, Section 10.2.1, at 76 n.194.

[12] *See* Excerpts, Section 10.2.1, at 76 n.192.

[13] *See* Excerpts, Section 10.2.2., at 76. Dynamic Risk does not allege any illegal and/or fraudulent acts associated with these costs that might subject them to the AGO's jurisdiction through the Commonwealth's consumer protection statute, G.L. c. 93A, or otherwise.

C.14 Union Representative of the Community Stakeholder Group

NEW ENGLAND GAS WORKERS ALLIANCE
100 MEDWAY ROAD #403, MILFORD, MASSACHUSETTS 01757

January 15, 2020

Mr. Patrick Vieth,
Executive Vice President, Dynamic Risk
Waterway Plaza Two, Suite 250
10001 Woodloch Forest Drive
The Woodlands, TX 77380

Re: Statewide Assessment of Gas Pipeline Safety, Commonwealth of Massachusetts, Review of Relevant Excerpt from Draft Final Report

The New England Gas Workers Alliance is comprised of four unions representing approximately 1,800 workers employed at Berkshire Gas, Eversource and National Grid.

We are writing in response to the excerpt from the Statewide Assessment of Gas Pipeline Safety Draft Final Report provided to our members Joe Kirylo, United Steelworkers Local 12003 and John Buonopane, United Steelworkers Local 12012-4.

Dynamic Risk asked us to 'identify any errors in the data or information' provided in their excerpt of the final report on Gas Pipeline Safety. This is unfortunately impossible since the two paragraphs on labor/management relations provided to us from the draft final report includes no information on where the anecdotal information was compiled, who the crews and contractors were or when and where the work took place.

In addition, while we appreciate the opportunity to offer feedback on this one section, we are frustrated and dismayed that Dynamic Risk deemed this two-paragraph excerpt as the only section that "pertains to observations made by the Panel that relate to the Labor Unions," when we have relayed many pressing safety issues to Dynamic Risk as workers with decades of experience on the ground in the Commonwealth. It is unclear to us whether they are substantially addressed in this report as we have not been provided materials beyond these two paragraphs on labor relations. It is shocking that after six months and 150 site visits by Dynamic Risk, where NEGWA members provided dozens of serious safety issues, the only feedback requested is to an allegation from a contractor about poor communication with a pipeline inspector.

Paragraph One of the Labor Relations excerpt notes a number of work sites in the Berkshire Gas service area where contractors and labor worked in harmony, communicated well and completed work together with no difficulties. However, as Dynamic Risk knows, relations with National Grid have been poor since the company locked out 1,200 gas workers more than a year ago for seven months. The 'anecdotal' reports from National Grid's service area relayed in Paragraph Two **without any specific information** appear to be little more than an attempt by National Grid-associated contractors to continue its battle with union gas workers.

The facts are simple:

- In areas where contractors are doing shoddy and potentially dangerous work, the best line of defense for the public and for first defenders is union gas workers who have repeatedly pointed out dangerous or defective work **including the example below**

- In keeping with union gas worker concerns about the quality of work, we have filed dozens of complaints regarding shoddy and potentially dangerous work from contractors over the last several years – and are still awaiting answers from utilities and the state

- There is no mention in these anecdotal reports of any presence of DPU inspectors at these jobs sites where labor and contractor relations were alleged to be so bad: A better question for Dynamic Risk and the Baker Administration to pursue is "where were the DPU inspectors?" when these alleged problems were encountered.

Finally, in order for us to understand what Dynamic Risk was told at the sites it observed we need real information that is not included in the draft. We are requesting all notes from the Dynamic Risk workers who compiled the anecdotal information and emails, texts and written materials submitted that contributed to this report. It is important for us to see where these alleged incidents occurred, and what union workers and contractors were involved.

Sincerely,

Danny O'Connell

Danny O'Connell	John Buonopane	Kathy Laflash	Judy Toomey
USW Local 12003	USW Local 12012-4	USW Local 12004	USW Local 12325

NEGWA Union Workers Are Stopping Natural Gas Contractors From Doing Unsafe Work

In November, 2019 a member of United Steelworkers Local 12004 was working as an inspector overseeing 3 separate 5-person crews of Eversource contractors.

One crew, working on the Avalon Oaks development in Marlborough was observed to have laid 80 feet of plastic piping at a depth less than the required 3 foot minimum. This depth is important as future utility service – water, sewer, etc. – relies on these depths for future digging. Pipe laid too shallow is at risk of being struck by an excavator, causing a hazardous gas leak that expels greenhouse gas into the atmosphere, and is in danger of igniting.

Non-union contractor crews should be educated in these safety requirements and other Operations & Maintenance rules. In this case however, when asked to remove the shallow piping to allow for a deeper trench, the foreman working for the contractor objected, disagreeing with the inspector from Local 12004, and initially refusing to remove the mislaid piping. The Local 12004 inspector is confident the contractor would have improperly backfilled this mislaid piping had he not been on site to witness the improper work.

This is one of many examples of contractors attempting to take shortcuts, creating disagreement with the union inspectors who insist on substandard work being corrected.

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Appendix D Personnel and Organizations that Supported the Assessment

This appendix lists personnel and organizations that supported the assessment.

D.1 Independent Review Panel

These individuals comprise the Independent Review Panel:

- Patrick H. Vieth, Executive Vice President, Dynamic Risk (Project Lead);
- Elizabeth Herdes, Contractor to Dynamic Risk (Project Co-Lead);
- Chery Campbell, Contractor to Dynamic Risk (Technical Lead); and
- Chris Hart, Advisor, Contractor to Dynamic Risk.

Todd Conklin, Advisor and Contractor to Dynamic Risk serves as an Advisor to the Independent Review Panel.

D.2 Project Technical Support Team

These individuals comprise the Project Technical Support Team:

- Terri Larson, Contractor to Dynamic Risk;
- Michael Courtien, Contractor to Dynamic Risk;
- Curtis Parker, Technical Director, Dynamic Risk;
- Bill Ho, Project Manager, Dynamic Risk;
- Karen Bowes, Project Administrator, Dynamic Risk
- Benjamin Mittelstadt, Director – Technical Services, Dynamic Risk ; and
- Trevor MacFarlane, President and CEO, Dynamic Risk.

D.3 DPU and EEA Representatives

DPU and EEA representatives are:

- Shane Early, General Counsel – Department of Public Utilities;
- George Yiankos, Director of Natural Gas Division, Department of Public Utilities; and
- Jamie Tosches, Deputy General Counsel – Energy, Executive Office of Energy and Environmental Affairs.

D.4 Gas Companies

Table D-1 lists Gas Companies.

Table D-1: Gas Companies

Gas Company	Gas Company Address	Primary Contact	Abbreviation	PHMSA Identification Code
Investor-Owned Local Distribution Companies				
Columbia Gas of Massachusetts (Bay State Gas Company)	Bay State Gas Company d/b/a Columbia Gas of Massachusetts 4 Technology Drive, Suite 250 Westborough, MA 01581	Mark Kempic, President	CGM	1209
Berkshire Gas Company	Berkshire Gas Company 115 Sheshire Road Pittsfield, MA 01202	Franklyn Reynolds	BER	1344
Blackstone Gas Company	Blackstone Gas Company 61 Main Street Blackstone, MA 01504	James Wojcik	BLA	1504
Eversource Energy (NSTAR Gas Company)	NSTAR Gas Company d/b/a Eversource Energy 247 Station Drive Westwood, MA 02090	William Akley, President	EVE	2652
Liberty Utilities (New England Natural Gas Company)	Liberty Utilities 36 5th Street Fall River, MA 02722-0911	Mark Smith, President	LIB	31770
Boston Gas Co (National Grid)	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid) 40 Sylvan Road Waltham, MA 02451	Marcy Reed, President	NGC	1640
Essex County Gas Co (National Grid)	NA	NA	-	4547
Colonial Gas Co - Lowell Div (National Grid)	NA	NA	-	11856
Cape Cod Gas Co (Div Of Colonial Gas Co) (National Grid)	NA	NA	-	2066
Unitil (Fitchburg Gas and Electric Light Company)	Unitil 6 Liberty Lane WestHampton, NH 03842	Thomas Meissner	UNI	5200
Municipal Gas Companies (4)				
Holyoke Gas & Electric	Holyoke Gas & Electric Department 99 Suffolk Street Holyoke, MA 01040	Brian Roy, Gas Superintendent	HOL	7330

Gas Company	Gas Company Address	Primary Contact	Abbreviation	PHMSA Identification Code
Middleborough Gas & Electric	Middleborough Gas & Electric Dept 2 Vine Street Middleborough, MA 02346	Richard Labossiere	MID	12444
Wakefield Municipal Gas & Light	Wakefield Municipal Gas and Light Department 480 North Avenue Wakefield, MA 01880	Peter Dion, General Manager	WAK	22035
Westfield Gas & Electric Light	Westfield Gas & Electric Light Dept. 100 Elm Street P.O. Box 990 Westfield, MA 01086-0990	Anthony Contrino, General Manager	WES	22511

D.5 Stakeholder Groups

This appendix lists Stakeholders that contributed to Phase 1 of this Assessment.

D.5.1 Elected Officials Group

This group comprises elected and appointed officials, including Massachusetts legislative leadership, Merrimac Valley officials, and town mayors. Members include:

- Honorable Robert A. DeLeo, House Speaker;
- Honorable Mike Barrett, State Senator;
- Honorable Thomas Golden, State Representative, Chairman;
- Honorable Bruce Tarr, Senate Minority Leader;
- Honorable Frank Moran, State Representative - 17th Essex District;
- Honorable Diana DiZoglio, Senator - 1st Essex District;
- Honorable Tram Nguyen, State Representative 18th Essex District;
- Honorable Barry Finegold, State Senator -2nd Essex & Middlesex District; and
- Mayor Dan Rivera, Mayor & CEO, City of Lawrence (MA).

D.5.2 Community Representatives Group

This group comprises union representatives, interested members from the general public, and selected State officials and/or other individuals with subject matter expertise. Members include:

- John Buonopane, USW Local 12012;
- Joe Kirylo, USW Local 12003;
- James (Red) Simpson, IBEW Local 326;
- Craig Pinkham, UWUA Local 369;

- Rebecca Tepper, Energy Chief, Mass. AG's Office;
- Peter Ostroskey, State Fire Marshall;
- Carl Weimer, Pipeline Safety Trust; and
- Zeyneb Magavi, Mothers Out Front.

D.5.3 Industry Representatives Group

This group comprises select executives from natural gas pipeline operators, key pipeline industry associations and/or experts working in complex operations in other industries such as nuclear power and commercial aviation. Members include:

- Jay Sutton, Southern Company Gas;
- Eric DeBonis, P.E., Southwest Gas;
- Christina Sames, AGA;
- Jose Costa, Northeast Gas Association;
- Clifford Johnson, PRCI;
- CJ Osman, INGAA;
- Professor Najmedin Meshkati, USC Viterbi School of Engineering; and
- Earl Carnes, Retired, Dept. of Energy.

Appendix E DPU Initial Questions for Assessment

Appendices E.1 and E.2 list questions the DPU seeks to answer through this Assessment.

E.1 Physical Integrity of the Statewide Gas Distribution System

1. Are the gas distribution companies' respective system designs of low/medium/high -pressure mains and associated service lines compliant with applicable Federal and state regulations?
2. Are there weaknesses or deficiencies (e.g., leaks, corrosion, asset condition, etc.) in the distribution system, and if so, what are recommendations for system changes? Are the gas distribution companies already addressing these changes pursuant to law, policy or regulation?
3. Based on a representative sample of site inspections, are there any additional distribution system weaknesses or deficiencies not otherwise identified through an assessment of system design?
4. Is the current inspection and replacement work optimized to properly manage risk?

E.2 Operation and Maintenance Policies and Practices of Gas Distribution Companies

1. What is the current level of adoption of best industry safety management practices, including API RP 1173, and what is the overall commitment to integrating safe practices in all distribution system operations and maintenance?
2. How adequate are the gas distribution companies' written operation and maintenance policies and procedures for their respective distribution systems, including policies and procedures for pipeline construction safety protocols and incident response?
3. Are there sufficient personnel, including Gas Company inspectors, and management structures and communication protocols in place at the gas distribution companies to ensure that safety and incident response protocols can be operationalized in all circumstances, including catastrophic situations?
4. What is your assessment of the operating pressure of each gas distribution company's system and its flow rates, including MAOP, any restrictions in pressure, flow and capacity, and the adequacy of response procedures in the event of abnormalities?
5. What is each gas distribution companies' degree of compliance with the Dig Safe statute, including compliance with notifications and inspections for pipeline construction?
6. Does the company keep effective records, including system maps, in such a way to complement all safety and incident response protocols?
7. Are there weaknesses or deficiencies in (a) any of the operation and maintenance policies, procedures and practices evaluated or, (b) the ability to operationalize policies and procedures in all circumstances, and if so, what are recommendations for improvement?

Based on a representative sample of site inspections, are there any additional weaknesses or deficiencies not otherwise identified through an assessment of written policies and procedures?

Appendix F Comparing Leaks Discovered to Leaks Repaired

As discussed in Section 8.1, the Gas Companies are required to report certain information to PHMSA each year. This information, submitted in the form of an Annual Report, provides detailed information related to the gas pipeline infrastructure for each Gas Company. The Gas Companies also provide information about the number of gas leaks *repaired* in a given year.

To provide a better view of the condition of the gas systems of the assets, the Panel asked the Gas Companies to provide data on the number of gas leaks *discovered* in each year from 2013-2018.

The analysis of the discovered leak data provided the Panel with an opportunity to better assess the condition of the Gas Companies' systems at a given point, and review the pace and trajectory of their pipe replacement programs in reducing leaks.

Table F-1 compares each of the Gas Companies' discovered leaks to the PHMSA-reported repaired leaks in 2018.

Table F-1: Comparison of Discovered and Repaired Leaks on Mains and Services (2018)

Gas Company	PHMSA ID	2018 MAINS - Leaks Discovered	2018 SERVICES - Leaks Discovered	2018 MAINS - Leaks Repaired (PHMSA)	2018 SERVICES - Leaks Repaired (PHMSA)
NGC		8,633	2,371	4,724	2,113
BOS	1640			4,254	1,669
ESS	4547			131	101
COL	11856			249	147
CAP	2066			90	196
CGM	2652	1,517	1,515	615	472
EVE	1209	735	460	1,231	1,430
BER	31770	185	63	188	173
LIB	1344	292	47	202	88
UNI	5200	111	289	239	131
BLA	1504	-	32		32
WES	7330	41	35	58	150
HOL	12444	58	39	3	13
MID	22035	3	13	53	8
WAK	22511	50		35	38
TOTAL		**11,625**	**4,887**	**7,348**	**4,648**

Appendix G Average National Leak and Representative Gas Company Leak Ratio[312]

Leak ratios are a straightforward method to determine if pipeline renewal programs are staying ahead of gas system deterioration. To assist in its Assessment of the Gas Companies, the Panel analyzed and developed a national leak ratio for mains and services. In addition, the Panel selected a gas company outside the Commonwealth (the Representative Gas Company) to demonstrate how effective pipeline renewal programs can reduce risk and help manage this aspect of public safety, customer satisfaction, and environmental issues over time.

The Representative Gas Company started an aggressive renewal program in the 1980s to replace its mains and services. By the end of 2018, the Representative Gas Company's gas distribution system was comprised entirely of plastic and protected steel assets, with no pipelines installed earlier than the 1950s.

The leak ratios presented in Table G-1 provide a high-level view of the condition of a gas system and should be viewed over time as trends. The progress in the trend is set out in Table G-2.

The Panel notes there are a number of variables that can impact leaks from year-to-year, some of which are outside the control of a gas company. A general downward trend over time indicates a reduction in risk or an improvement in overall asset condition over time.

Table G-1: National and Representative Gas Ratios for Mains and Services (2013 and 2018)

Gas Company	2013		2018	
	Mains	Services	Mains	Services
National	9.85	4.27	8.00	5.00
Representative Gas Company	1.35	0.11	0.69	0.14

Table G-2: Leak Ratio Trends on Mains and Services (2013-2018)

Year	National – Mains	National – Services	Representative Gas Company – Mains	Representative Gas Company - Services
2013	9.85	4.27	1.35	0.11
2014	10.10	4.52	1.20	0.12
2015	9.47	4.99	0.90	0.08
2016	8.57	4.97	0.78	0.11
2017	8.32	4.92	0.55	0.12
2018	8.00	5.00	0.69	0.14

[312] These leak ratios are calculated based on leaks reported to PHMSA from 2013-2018. The data likely contains some unknown number of leaks discovered in earlier years that have *remained on the books* over time. This is not true for the data the Panel relied on in calculating the leak ratios for each Gas Company as part of this Assessment, which only reflects leaks discovered during a limited period. Like the data used to calculate the leak ratios for the Gas Companies, the leak data used for the tables in this appendix exclude leaks caused by excavation because such leaks do not reflect the condition of the assets. While the leak ratios in this appendix may contain some variation in absolute values, the Panel has confidence that ratios in this appendix provide the correct order of magnitude that can be compared to the Gas Company leak ratios.

Appendix H Safety Case Issued to Gas Companies

Figure H-1 is a safety case issued to Gas Companies by the Panel on September 9, 2019.

Safety Case
From Gas Pipeline Safety Assessment

This bulletin is intended to heighten awareness and to provide observations, findings, and recommendations for enhancing safety.

Observations:
Through the course of visiting numerous field sites involving excavation of gas pipeline mains and services, the Panel observed inconsistent understanding and application of the tolerance zone for excavation using mechanical equipment near live gas mains and services. (see photos).

As a follow up to this observation, the Panel reviewed Gas Company's O&M Manuals, industry guidance, and the language in the MA Dig Safe laws and regulations. We observed in many cases, it may be giving rise to unintended ambiguity as to when hand-digging is required to create an appropriate safety or tolerance zone. Since the practice of hand digging may serve as an essential control in preventing failures, understanding what is occurring in the field is important and provides an opportunity to learn why deviations may occur.

Findings:
There may be unintended divergence between management's expected application of the tolerance zone and the actual use of mechanical means to excavate around live gas mains and services in the field. For example, a typical industry-leading practice is to use hand-digging to not only locate the gas asset, but to excavate within 18-inches on top of, on each side of, and below the gas asset.

The Panel observed variances in:

- When to begin hand-digging instead of using the backhoe. A few began a foot or more away, others 2-3"; one operator stated he could brush the back of the bucket along the top of the cast iron pipe.
- When to return to using the backhoe. There is widespread practice of hand-digging only until the asset becomes visible. Often the return to using the backhoe is accompanied by placing the face of the blade of a shovel against the asset as protection while the backhoe bucket brushes against the back of the shovel blade.

As a Recommendation: The Panel recommends each Gas Company review its own field practices with regard to mechanical excavation and hand-digging requirements, and take appropriate steps to align field practices with the Company's view of the appropriate practices, processes and procedures necessary to ensure application of safe and consistent excavation practices.

Figure H-1: Issued Safety Case

Appendix I Assessment Data from the Phase 1 Summary Report

Table I-1 to Table I-3 contain Assessment data (2017).

I.1 Tables of PHMSA Data of Mains and Services in NE and MA 2017

Table I-1: PHMSA Data of Mains in Northeast (2017)

State	Miles Main (% Total Main)		
	Total Main	**Cast Iron**	**Steel (Unprotected)**
NY	49,126	3,420 (7%)	6,522 (13%)
PA	48,346	2,661 (6%)	7,681 (16%)
NJ	34,961	4,143 (12%)	1,688 (5%)
MA	21,669	3,049 (14%)	2,251 (10%)
CT	8,109	1,251 (15%)	188 (2%)
RI	3,205	730 (23%)	395 (12%)
NH	1,968	86 (4%)	22 (1%)
ME	1,239	39 (3%)	13 (1%)
VT	848	---	---
NE Total	**169,472**	**15,378 (9%)**	**18,760 (11%)**
US		24,493	54,847
NE % of US	13% of US	63% of US	34% of US
MA % of US	2% of US	12% of US	4% of US

Table I-2: PHMSA Data of Services in Northeast (2017)

State	Count of Services (% Total Services)		
	Total Services	**Cast Iron**	**Steel (Unprotected)**
NY	3,241,702	4,449 (0.1%)	369,316 (11%)
PA	2,879,281	73 (0%)	309,229 (11%)
NJ	2,389,910	---	163,642 (7%)
MA	1,336,678	1,397 (0.1%)	199,010 (15%)
CT	450,680	22 (0%)	52,023 (12%)
RI	196,505	129 (0.1%)	42,969 (22%)
NH	93,963	16 (0%)	6,473 (7%)
ME	36,511	26 (0%)	205 (1%)
VT	39,818	---	---
NE Total	**10,665,048**	**6,112**	**1,142,867**
US	68,636,596	7,652	3,095,829
NE % of US	16% of US	80% of US	37% of US
MA % of US	1.9% of US	18.3% of US	6.4% of US

Table I-3: PHMSA Data of Mains and Services for Massachusetts Gas Companies (2017)

Doc ID Prefix	PHMSA ID	Total Main			Total Services		
		Total Main	Cast Iron	Steel (Unp)	Total Services	Cast Iron	Steel (Unp)
Investor-Owned Local Distribution Companies (7)							
CGM	1209	4,985	471	218	271,552	-	37,002
BER	1344	761	58	34	32,155	1	2,915
BLA	1504	55	-	-	1,440	-	-
EVE	2652	3,280	335	666	203,472	8	31,285
LIB	31770	619	110	83	36,687	-	10,840
NGC		-	-	-	-	-	-
BOS	1640	6,367	1,768	1,087	506,905	1,368	98,873
ESS	4547	866	73	18	52,100	4	4,296
COL	11856	1,397	90	66	77,525	-	4,761
CAP	2066	2,475	0	48	117,390	15	3,317
UNI	5200	274	49	5	11,046	-	2,316
Municipal Gas Companies (4)							
HOL	7330	186	53	-	7,949	-	1,275
MID	12444	106	7	1	4,750	-	196
WAK	22035	87	1	24	5,000	-	930
WES	22511	209	34	-	8,707	1	1,004
Total		**21,666**	**3,049**	**2,251**	**1,336,678**	**1,397**	**199,010**

Appendix J Abbreviations and Glossary

Table J-1 lists and provides the meanings for terms and abbreviations used in this Final Report. Table J-2 lists and defines terms and phrases used in this Final Report. In documents that pre-date this Final Report, the definitions presented herein shall take precedence.

Table J-1: Abbreviations

Abbreviation	Meaning
AG	Attorney General
AG Office	Attorney General's office
AGA	*American Gas Association*
API	*American Petroleum Institute*
API 1173	*See API RP 1173*
API RP 1173	API Recommended Practice for Pipeline Safety Management System
Approx.	Approximately
ASME	American Society of Mechanical Engineers
ASME B31.8S	Managing System Integrity of Gas Pipelines
ASRS	Aviation Safety Reporting System, operated by the National Aeronautics and Space Administration
Assessment	Statewide Assessment of Gas Pipeline Safety conducted for the Commonwealth of Massachusetts. *See also* "Project"
BD	Business development
BER	Berkshire Gas Company
BLA	Blackstone Gas Company
BOS	Boston Gas Co (National Grid)
BP	British Petroleum
BSEE	*Bureau of Safety and Environmental Enforcement*, which regulates the US offshore energy industry
CA	California
CAP	Cape Cod Gas Co (Div Of Colonial Gas Co) (National Grid)
CAST	Commercial Aviation Safety Team
CEO	Chief executive officer
CER	Canada Energy Resource (formerly National Energy Board)
CFR	*Code of Federal Regulations*
CGM	Columbia Gas of Massachusetts (Bay State Gas Company)
CI	Cast Iron
CMR	*Code of Massachusetts Regulations*
CNG	Compressed Natural Gas
COL	Colonial Gas Co - Lowell Div (National Grid)
Commonwealth	Commonwealth of Massachusetts

Abbreviation	Meaning
Country	Reference to the United States of America
CP	Cathodic Protection
CT	Connecticut
CV	Curriculum Vitae, or Resume
DEP	Department of Environmental Protection
Dig Safe	Dig Safe is a not-for-profit clearinghouse that notifies participating utility companies of your plans to dig
DIMP	Distribution Integrity Management Plan
DOER	Department of Energy Resources (Massachusetts)
DPU	Department of Public Utilities (Commonwealth of Massachusetts)
Dynamic Risk	Dynamic Risk Assessment Systems, Inc.
EEA	Executive Office of Energy and Environmental Affairs for the Commonwealth of Massachusetts
ER	Emergency response
ESS	Essex County Gas Co (National Grid)
EVE	Eversource Energy (NSTAR Gas Company)
FAA	Federal Aviation Administration
FAQ	Frequently asked questions
Gas	Natural gas
GHG	Green House Gas
GIS	Geographical Information System
GSEP	Gas System Enhancement Plan
HDD	Horizontal directional drilling
HOL	Holyoke Gas & Electric
HP	High pressure (generally 60 psig or higher)
IBEW	International Brotherhood of Electrical Workers
IC	Internal corrosion
ICS	Incident Command Structure
ID	Inside diameter
INGAA	Interstate Natural Gas Association of America
IP	Intermediate pressure (generally less than 60 psig)
IR	Information Request
LAUF	Lost and unaccounted for (gas)
LDC	Local Distribution Company (natural gas)
LIB	Liberty Utilities (New England Natural Gas Company)
LNG	Liquid natural gas
LP	Low pressure (generally inches of water column)
LPG	Liquified petroleum gas

Abbreviation	Meaning
MA	Commonwealth of Massachusetts
MAOP	Maximum allowable operating pressure
ME	Maine
MID	Middleborough Gas & Electric
MTR	Mill test report
NA	Not applicable
NE	Northeast
NGA	Northeast Gas Association
NGC	National Grid Companies comprised of Boston Gas Co, Essex County Gas Co, Colonial Gas Co – Lowell Div, and Cape Cod Gas Co
NH	New Hampshire
NJ	New Jersey
NLOPB	Newfoundland and Labrador Offshore Petroleum Board (Canada)
NOPV	Notice of Probable Violation
NRC	Nuclear Regulatory Commission
NSTAR	NSTAR gas utility; subsidiary of Eversource
NY	New York
O&M	Operations and Maintenance
OF	Outside force
OPP	Over Pressure Protection
OSHA	Occupational Safety and Health Administration
P.E.	Professional engineer
PA	Pennsylvania
PDCA	Plan-Do-Check-Act
PDF	Portable document file (Adobe filename extension)
PE	Professional engineer
Phase 1	The first approved portion of this Assessment.
Phase 2	The expected second phase of this Assessment.
PHMSA	Pipeline and Hazardous Materials Safety Administration (part of the U.S. Department of Transportation)
PPE	Personal protective equipment
PRCI	Pipeline Research Council International
Project	*See Assessment*.
PSMS	Pipeline Safety Management System
Q&A	Question and Answer
QA	Quality assurance
QC	Quality control
QR	Quick response

Abbreviation	Meaning
RI	Rhode Island
SCADA	Supervisory Control and Data Acquisition
SME	Subject matter expert
SMS	Safety Management System
SOP	Standard operating procedure
SVP	Senior Vice President
SW	Southwest
TGP	Tennessee Gas Pipeline Company (a gas transmission company)
TX	Texas
U.S.	United States
UNI	Unitil
US	United States
USC	United States Code
USW	United Steelworkers; trade union
UWUA	Utility Workers Union of America; trade union
VA	Virginia
VP	Vice President
VT	Vermont
WAK	Wakefield Municipal Gas & Light
WES	Westfield Gas & Electric Light

Table J-2: Glossary

Abbreviation	Meaning
220 CMR	Code of Massachusetts Regulations Title 220 (220 CMR); Specifically, applicable Sections 100.00 through 113.00
49 CFR Part 192	Code of Federal Regulations (CFR) for the Transportation Of Natural And Other Gas By Pipeline
Affected Stakeholder Group	*See Elected Officials Group.*
CAST	Commercial Aviation Safety Team, a voluntary cooperative Government-Industry initiative and is co-chaired by the Federal Aviation Administration (FAA) and the Aviation Industry
Chatham House Rules	Procedure where information that is received can be used subject to guideline restrictions. However, neither the identity nor the affiliation of the speaker(s) may be revealed
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board, joint agency of the Governments of Canada and Nova Scotia responsible for the regulation of petroleum activities in the Newfoundland and Labrador Offshore Area
C-NSOPB	Canada-Nova Scotia Offshore Petroleum Board, is the independent joint agency of the Governments of Canada and Nova Scotia responsible for the regulation of petroleum activities in the Nova Scotia Offshore Area
Commonwealth of Massachusetts	Commonwealth, or State, of Massachusetts.
Community Representatives Group	Stakeholder group of 7-9 individuals comprised of union representatives, interested members from the general public, and selected State officials and/or other individuals with subject matter experts, chosen by the Panel with input and advice from the Commonwealth. (Note this was formerly referred to as the External Stakeholder Group. Stakeholder Group comprised primarily of certain parties that have expressed direct interest in this Assessment (Note: this was formerly referred to as the External Stakeholder Group)
Customer	A *customer* is an individual or corporation who pays a regular fee to use a public utility (e.g., gas or electricity). Fees are usually based on the quantity of utility consumed by the customer. This term is synonymous with *ratepayer*.
Designated Participants	Individuals that have been invited and accepted to serve as a member of a Stakeholder Group
Dig-ins	External force that impacts a buried pipeline, most commonly via exaction equipment
DPU Leadership Team	Designated Individuals from the DPU and other agencies that provide support and direction in the execution of this Assessment.
Elected Officials Group	Stakeholder Group of 10-15 individuals comprised of elected or appointed government officials (Note: this was formerly referred to as the Affected Stakeholder Group)
Evaluator	*See Panel*
External Stakeholder Group	*See Community Representatives Group*
Gas Companies	Seven (7) Investor-Owned Local Distribution Companies and four (4) Municipal Gas Companies (4) designated by the DPU to participate in this Assessment
Gas Company Representatives	Generally, two (2) individuals that shall serve as the lead and co-lead points of contact plus, one individual designated by the DPU as the Gas Company representative, if different from the lead or co-lead.
Guidelines for Engagement	Guidelines for participation this Assessment, one each for the Gas Companies, DPU, and the Stakeholder Groups

Abbreviation	**Meaning**
Independent Evaluator	*See Panel*
Independent Panel Members	Five (5) designated individuals that comprise the Panel
Independent Review Panel	*See Panel*
Industry Advisory Group	*See Industry Representatives Group*
Industry Representatives Group	Stakeholder Group comprised of approximately 5 individuals including select Executives from natural gas pipeline operators, key pipeline industry associations and/or experts working in complex operations in other industries such as nuclear power and commercial aviation. Note: this was formerly referred to as the Industry Advisory Group)
Integrity	In the context of pipelines, *integrity* refers to programs, practices and actions used to effectively manage and mitigate hazards and risks related to pipeline integrity management
Interested Parties	Individuals and organizations that can affect gas pipeline safety include State Legislators, U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA), Attorney General's (AG) Ratepayer Advocacy Office, Utility Unions, Environmentalists, Customers, and Municipal Governments (local rule state). This also includes the EEA, DPU, and Gas Companies
Leak prone pipe	Certain pipes that are more susceptible to failures that result in a release of gas; most commonly comprised of cast iron pipe and steel that is not cathodically protected.
Listening Session	Session for sharing information about the process and soliciting input; not a Q & A Session
Operator(s)	*See Gas Companies*
Panel	Collectively, the five (5) Independent Panel Members; Also referred to as the Independent Review Panel, Evaluator, and Independent Evaluator
Project Leadership Team	Designated representatives from the project team and designated project leadership representatives from the DPU and/or other supporting agencies. For clarity, this currently includes Patrick Vieth, Elizabeth Herdes, Bill Ho, Shane Early George Yiankos, and Jamie Tosches.
Project Team	Dynamic Risk team that is executing this Assessment and includes the Panel.
Ratepayer	A *ratepayer* is an individual or corporation who pays a regular fee to use a public utility (e.g., gas or electricity). Fees are usually based on the quantity of utility consumed by the customer. This term is synonymous with *customer*.
Rev	Revision number, typically “A,” “B” etc., to reflect substantive modifications from the previously marked revision.
Review Panel	*See Panel*
Sharefile	ShareFile, operated by Citrix, is a privately-owned company that allows users to send and receive documents securely that uses a trusted method of encrypted document transfer.