The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 15-GLR-01 September 18, 2015

Report on the Prevalence of Natural Gas Leaks in the Natural Gas System to the Joint Committee on Telecommunications, Utilities, And Energy, and the Joint Committee on Public Safety and Homeland Security, pursuant to An Act Relative to Natural Gas Leaks, St. 2014, c. 149, § 9.

REPORT TO THE LEGISLATURE ON THE PREVALENCE OF NATURAL GAS LEAKS IN THE NATURAL GAS SYSTEM

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I. INTRODUCTION

On June 26, 2014, Governor Patrick signed into law An Act Relative to Natural Gas Leaks, St. 2014, c. 149 ("the Act"). Section 9 of the Act requires the Department of Public Utilities ("Department") to issue a report addressing the prevalence of natural gas leaks in the natural gas system. Specifically, Section 9 requires that the Department's report include, but not be limited to, the following: (1) the total number of Grade 1, Grade 2, and Grade 3 leaks as classified in Section 144 of Chapter 164 of the General Laws and reported in the previous year; (2) estimates for lost and unaccounted for natural gas ("LAUF") and methane emissions as a result of such Grade 1, Grade 2, and Grade 3 leaks; and (3) the time and cost estimates for eliminating the backlog of Grade 1, Grade 2, and Grade 3 leaks. The Department must submit its report to the House and Senate Chairs of the Joint Committee on Telecommunications, Utilities and Energy, and the House and Senate chairs of the Joint Committee on Public Safety and Homeland Security within one year of the effective date of the Act, on or before September 24, 2015. See St. 2014, c. 149, § 9. The Department is pleased to present this report to the Joint Committee on Telecommunications, Utilities and Energy, and the Joint Committee on Public Safety and Homeland Security.

Natural gas leaks occur in the gas distribution system for a number of reasons, including the age of the infrastructure, corrosion, and damage due to other underground construction projects, also referred to as encroachment.[1] A significant reason for the

[1] Encroached pipe includes cast-iron pipe that is eight inches or smaller in diameter that has been exposed and undermined by a trench crossing the natural gas pipeline or by an adjacent, parallel excavation. 220 C.M.R. §§ 113.06, 113.07.

occurrence of natural gas leaks in Massachusetts is the presence of certain aging, leak-prone infrastructure, including non-cathodically protected steel,[2] cast-iron pipe,[3] and wrought-iron pipe.[4] A recent study commissioned by the Department estimates that there are over 6,000 miles of aging infrastructure in Massachusetts that is comprised of materials that are vulnerable to natural gas leakage. The Department has recognized that there may be public safety, service reliability, and environmental issues associated with the continued existence and aging of leak-prone facilities in gas companies' distribution systems. Bay State Gas Company, D.P.U. 09-30, at 133 (2009); New England Gas Company, D.P.U. 10-114, at 56 (2011). The Department has determined that a sustained replacement of aging infrastructure facilities is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121 (2010); D.P.U. 10-114, at 56; D.P.U. 09-30, at 133-134.

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[2] Cathodic protection is a technique to control the corrosion of metal surface by making the structure work as a cathode of an electrochemical cell. NACE International Standard Practice, SP0169-2007.

[3] Applies to gray cast iron that is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal. Because the carbon flakes do not bond with the ferrous material on the molecular level, the metal is brittle and susceptible to stress cracking under pressure situations. American Gas Association, Gas Piping Technology Committee.

[4] Together with cast iron, wrought iron pipelines are among the oldest energy pipelines constructed in the United States. The degrading nature of iron alloys, the age of the pipelines, and pipe joints design have greatly increased the risk involved with continued use of such pipeline. http://opsweb.phmsa.dot.gov/pipeline_replacement/.

As discussed below, pursuant to Section 9, the Department has gathered data from local gas distribution companies and municipal gas operators regarding the number of Grade 1, Grade 2, and Grade 3 gas leaks on the Commonwealth's natural gas system as reported in 2014, estimates of LAUF and methane emissions, and estimated costs to eliminate identified Grade 1, Grade 2, and Grade 3 leaks. It is important to note that while this report provides the total number of Grade 1, Grade 2, and Grade 3 leaks identified during 2014, as required by Section 9, this data does not represent the number of ongoing, unrepaired leaks as of the date of this report. Rather, the actual number of natural gas leaks may change daily as gas distribution companies and municipal gas operators repair identified leaks,[5] and where, because of the nature of certain aging infrastructure as well as other causes of natural gas leaks, new leaks are identified and classified. The number of Grade 1, Grade 2, and Grade 3 gas leaks reported in 2014 is presented in Section II, below.

Additionally, the Department's report shows that the challenges posed by certain aging infrastructure are being addressed by the Department and the gas industry in several ways. First, in recognizing the public safety and environmental issues posed by natural gas leaks, the Department has taken proactive steps to address issues regarding the replacement or repair of leak-prone infrastructure. In the early 1990s, the Department promulgated regulations (220 C.M.R. §§ 113.00 et seq.) prohibiting the installation of cast-iron pipe for the distribution

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5 Gas distribution companies are required to repair Grade 1 leaks, which present an existing or probable hazard, as immediately as possible and to take continuous action until conditions are no longer hazardous, and to repair Grade 2 leaks, which are non-hazardous but justify repair based on probably future hazard, within twelve months from the date of classification. G.L. c. 164, § 144(b)(2) & (3).

of gas after April 12, 1991. Beginning in 2009, the Department began approving targeted infrastructure replacement factor programs ("TIRFs") for several gas distribution companies in order to accelerate the replacement of leak-prone infrastructure. Similarly, pursuant to G.L. c. 164, § 145,[6] gas distribution companies may, in the interest of public safety and to reduce LAUF, submit to the Department accelerated infrastructure replacement plans to replace aging natural gas pipeline infrastructure. On October 31, 2014, seven gas distribution companies each submitted to the Department their first annual accelerated infrastructure replacement plan,[7] referred to as gas system enhancement plans ("GSEPs").[8] The Department approved the GSEPs on April 30, 2015. Because the intent of the pipeline replacement program is to reduce the number of natural gas leaks in the natural gas system, as well as to reduce LAUF and methane emissions, we discuss the pipeline replacement programs in more detail in Section III, below.[9]

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[6] Section 2 of the Act added G.L. c. 164, § 145.

[7] The seven gas distribution companies are: the Berkshire Gas Company; Bay State Gas Company d/b/a Columbia Gas of Massachusetts; Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities; Boston Gas Company and Colonial Gas Company d/b/a National Grid; NSTAR Gas Company d/b/a Eversource Energy; and Fitchburg Gas and Electric Light Company d/b/a Unitil.

[8] Under the proposed GSEPs, the seven gas distribution companies plan to replace a total of approximately 6,023 miles of aging infrastructure in Massachusetts over the next 20 years, with the exception that Colonial Gas Company intends to complete replacement of aging infrastructure within eight years, and NSTAR Gas Company plans to do so within 25 years.

[9] This section will also provide information on the amount of leak-prone infrastructure within each gas distribution company's system.

Additionally, in 2012, the Department hired an independent consultant, ICF International ("ICF"), to perform a comprehensive review of issues pertaining to natural gas leaks, LAUF, and methane emissions as a result of natural gas leaks. ICF recently submitted its report to the Department, and the Department is reviewing ICF's recommendations. We discuss the ICF report in Section IV, below. Further, G.L. c. 164, § 144[10] prescribes a timeline in which gas distribution companies must repair and/or monitor natural gas leaks depending on the hazard posed by the leak. We discuss uniform gas leak classification requirements in more detail in Section V, below.

For purposes of this report, the Department gathered data through information requests issued to each local gas distribution company and each municipal gas operator in the Commonwealth, as follows: The Berkshire Gas Company ("Berkshire"); Blackstone Gas Company ("Blackstone"); Bay State Gas Company d/b/a Columbia Gas of Massachusetts ("Bay State"); Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities ("Liberty Utilities"); Boston Gas Company and Colonial Gas Company d/b/a National Grid ("National Grid"); NSTAR Gas Company d/b/a Eversource Energy ("NSTAR"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); Holyoke Gas & Electric Department ("Holyoke"), Middleborough Gas & Electric Department ("Middleborough"), Wakefield Municipal Gas and Light Department ("Wakefield"), and Westfield Gas & Electric Light Department ("Westfield"). The Department directed each gas operator to provide detailed information on (i) the total number of Grade 1, Grade 2, and Grade 3 leaks as

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10 Section 2 of the Act added G.L. c. 164, § 144.

classified in Section 144 of Chapter 164 of the General Laws and reported in 2014; (ii) estimates for lost and unaccounted for natural gas and methane emissions as a result of such Grade 1, Grade 2, and Grade 3 leaks; and (iii) the time and cost estimates for eliminating the backlog of Grade 1, Grade 2, and Grade 3 leaks.[11] The Department issued a second set of information requests to the gas companies and municipal gas operators in order to clarify the first round of responses. Additionally, the Department reports gas leakage data submitted in the Massachusetts addendum to an annual filing required by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA"), referred to as Form PHMSA F 7100.1-1 ("2014 PHMSA Addendum")[12].

II. PREVALENCE OF NATURAL GAS LEAKS IN THE NATURAL GAS SYSTEM

A. Introduction

General Law c. 164 § 144, requires the gas distribution companies to assess a grade to all reported natural gas leaks based upon the hazard posed by the leak and, in turn, prescribes

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11 Pursuant to G.L. c. 164, § 144, the gas distribution companies are required to report in their annual service quality ("SQ") reports the location of each Grade 1, Grade 2, and Grade 3 leaks existing as of the date of the report, the date each leak was classified, and the dates of repairs performed on each Grade 1, Grade 2, and Grade 3 leak. While the gas companies submitted lists of gas leaks by location and grade, the SQ reports did not provide total numbers of leaks by grade. The Department issued information requests to require the companies to calculate total number of leaks by grade, and to gather additional information on the companies' methods for estimating LAUF and methane emissions. Nearly all gas distribution companies confirmed that the data for the reported number of Grade 1 through Grade 3 gas leaks provided in response to information requests is the same as that reported in their SQ reports. Any exceptions are noted and explained in the company-specific data sections, below.

12 40 C.F.R. Part 191 requires submittal of Form PHMSA F 7100.1-1 to PHMSA. The Department requires filing of the PHMSA Addendum.

a timeline in which gas distribution companies and municipal gas operators must repair and/or monitor natural gas leaks depending on the hazard posed by the leak. Pursuant to G.L. c. 164, § 144(b)(2), a Grade 1 leak is considered an existing or probable hazard that gas distribution companies are required to repaired "as immediately as possible" and for which the gas distribution company must provide continued monitoring until the leak is eliminated. A Grade 2 leak is non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard. G.L. c. 164, § 144(b)(3). Gas distribution companies and municipal gas operators are required to repair Grade 2 leaks, or replace the associated main, within twelve months, and to reevaluate Grade 2 leaks every six months until eliminated. G.L. c. 164, § 144(b)(3). A Grade 3 leak is considered non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. G.L. c. 164, § 144(b)(4). Gas distribution companies and municipal gas operators must reevaluate Grade 3 leaks during the next scheduled survey, or within twelve months from the date last evaluated, whichever occurs first, until the leak is eliminated or the main is replaced. G.L. c. 164, § 144(b)(4).[13]

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13 The following are complete definitions of Grade 1, Grade 2, and Grade 3 gas leaks as provided in G.L. c.164, § 144:

> A Grade 1 leak shall be a leak that represents an existing or probable hazard to persons or property. Grade 1 leaks require repair as immediately as possible and continuous action until the conditions are no longer hazardous. The gas company shall immediately schedule a completion of repairs and the condition shall be kept under continuous surveillance until the hazard or source of the leak is eliminated. Whenever appropriate and feasible, a gas company shall notify the fire department and chief law enforcement officer in each city or town where a Grade 1 leak is identified;

Section II.B, below, presents company- and operator-specific gas-leak data, as follows: (1) Grade 1, Grade 2, and Grade 3 gas leaks in calendar year 2014 as reported to the Department; (2) estimates for LAUF and methane emissions; and (4) the time and cost estimates for eliminating the backlog of Grade 1, Grade 2, and Grade 3 leaks. Section II.C, below, provides a summary of all Grade 1, Grade 2, and Grade 3 leaks.

As stated above, it is important to note that the total number of natural gas leaks as discussed below does not represent the number of ongoing, unrepaired leaks as of the date of this report. The number of gas leaks on the gas distribution system may fluctuate daily for a number of reasons, including that gas distribution companies are required to repair Grade 1 leaks "as immediately as possible", gas distribution companies engage in ongoing repair of other Grade 2 and Grade 3 leaks, and new Grade 1, Grade 2, and Grade 3 leaks arise as a

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A Grade 2 leak shall be a leak that is recognized as non-hazardous to persons or property at the time of detection, but justifies scheduled repair based on probable future hazard. The gas company shall repair Grade 2 leaks or replace the main within 12 months from the date the leak was classified. All Grade 2 leaks shall be reevaluated by a gas company at least once every 6 months until eliminated; provided, however, that the frequency of reevaluation shall be determined by the location and magnitude of the leakage condition; and

A Grade 3 leak shall be a leak that is recognized as non-hazardous to persons or property at the time of detection and can be reasonably expected to remain non-hazardous. The gas company shall reevaluate Grade 3 leaks during the next scheduled survey, or within 12 months from the date last evaluated, whichever occurs first, until the leak is eliminated or the main is replaced. A municipal or state public safety official may request a reevaluation of a Grade 3 leak prior to the next scheduled survey, or sooner than 12 months of the date last evaluated, if the official reasonably believes that the Grade 3 leak poses a threat to public safety.

result of encroachment or due to certain aging infrastructure. Accordingly, the data provided in this report should be viewed as a cumulative total of Grade 1, Grade 2, and Grade 3 leaks as reported in calendar year 2014, along with the associated cost estimates to fix the unrepaired leaks that existed on each reporting entity's gas distribution system as of the end of calendar year 2014. The report also identifies the number of unrepaired leaks, by grade, existing as of the end of calendar year 2014.

Second, it is important to note that the gas distribution companies and municipal gas operators report that there is no standard industry approach for calculating LAUF or methane emissions by leak grade (i.e., LAUF or methane emissions associated only with Grade 1, Grade 2, or Grade 3 leaks that excludes other causes) (see Exhs. DPU-Bay State 1-6; DPU-Berkshire 2-2; DPU-Liberty Utilities 1-7; DPU-National Grid 1-6; DPU-NSTAR 1-7; DPU-Unitil 1-7). Therefore, the LAUF and methane values contained in this report, unless otherwise indicated, are not broken down by leak grade. Further, the Department has determined that the LAUF value associated with leakage, as reported to the Department by each gas distribution company and municipal gas operator in its annual 2014 PHMSA Addendum, is the appropriate measurement to include in this report.

Third, all gas distribution companies and municipal operators that are required to report methane emissions currently do so in accordance with the Massachusetts Greenhouse Gas Reporting Regulation, 310 CMR § 7.71 ("310 C.M.R. § 7.71")(see, e.g., Exhs. DPU-Bay State 1-7; DPU-Berkshire 1-6; DPU-National Grid 1-7). 310 C.M.R. § 7.71 requires that gas distribution companies and operators estimate methane emissions by applying the leak factors identified in the United States Environmental Protection Agency ("US EPA") Greenhouse Gas regulations, 40 C.F.R. Part 98, subpart W, Table W-7 ("40 C.F.R. Part 98"), to various types of pipe material in order to estimate the average volume of methane released into the environment through fugitive emissions or leaks ("40 C.F.R Part 98 Methodology"). Per the 40 C.F.R. Part 98 Methodology, the total amount of methane emissions resulting from the main and service leakage calculation is based on the total inventory of pipe sorted by material type multiplied by the published leakage rate per length of pipe type, service or main, for any given pipe material. Factors for fugitive methane emissions associated with individual regulator stations, commercial meter and regulator installations, and residential meter and regulator stations are also used to estimate methane emissions from total leakage. The gas companies and municipal operators that use this approach state that it is the most widely accepted methodology used by the natural gas industry as a means to estimate methane emissions from natural gas facilities and, therefore, all leakage on the natural gas system (see, e.g., Exhs. DPU-Bay State 1-7; DPU-Berkshire 1-6; DPU-National Grid 1-7).

Finally, in order to present the data in a consistent manner, the Department reports LAUF in one thousand cubic feet ("Mcf") and methane emissions in metric tons ("MT").

B. Gas Leaks on Gas Distribution Company and Municipal Gas Operator Distribution Systems

1. Bay State

Bay State reports that it had a total of 2,797 Grade 1 leaks, 2,162 Grade 2 leaks, and 3,145 Grade 3 leaks on its distribution system in 2014 (Exh. DPU-Bay State 1-3). At the end of 2014, Bay State had a total of 3,439 remaining unrepaired leaks, consisting of 494 Grade 2 leaks, and 2,945 Grade 3 leaks (Exh. DPU-Bay State 2-2, Att.). Bay State estimates that it would cost $25,030,937, and take 135,615 person hours, to repair the 3,439 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exh. DPU-Bay State 2-2, Att.).

Bay State does not directly estimate methane emissions or LAUF associated with Grade 1, Grade 2, and Grade 3 leaks (Exhs. DPU-Bay State 1-6; DPU-Bay State 1-7). Bay State states that it is, however, able to estimate volumes of gas, or LAUF gas volumes, associated with the overall leaks on its system (Exh. DPU-Bay State 1-6). Bay State calculates and reports fugitive greenhouse gas emissions due to leakage in accordance with 310 C.M.R. § 7.71 (Exh. DPU-Bay State 1-7). Bay State provides estimated leakage information as part of its report for the Massachusetts Greenhouse Gas Emissions Reporting Program that is filed annually with the Massachusetts Department of Environmental Protection ("DEP"). Bay State explains that the LAUF and associated methane emissions for calendar year 2014 are based on the DEP Greenhouse Gas Inventory for which the DEP requires Bay State to use the EPA protocols in estimating volume of gas lost from its gas mains, services, and measurement and regulator ("M&R") stations (Exh. DPU-Bay State 1-6). The protocols provide typical gas loss estimating factors for a given length of different main material types, and a unit basis for services and M&R stations (Exh. DPU-Bay State 1-6).

Bay State explains that it applies the EPA emissions factors as provided in the 40 C.F.R. Part 98 Methodology to calculate fugitive methane emissions required for Massachusetts reporting (Exh. DPU-Bay State 1-7). Bay State estimates a system-wide LAUF leakage volume of 278,532.2 Mcf of LAUF and 6,133.8 MT of methane emissions in 2014 (Exh. DPU-Bay State 2-1, Tab. 2-1; Bay State 2014 PHMSA Addendum). Table 1, below, provides a summary of Bay State-specific gas leak and emissions data for calendar year 2014.

Table 1: Bay State

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage [14] (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
2,979*	2,162	3,145	8,104	278,532.2	6,133.8	$25,030,937

*As stated above, no Grade 1 leaks existed on Bay State's gas distribution system at the end of calendar year 2014.

2. Berkshire

Berkshire reports that it had a total of 75 Grade 1 leaks, 227 Grade 2 leaks, and 356 Grade 3 leaks on its gas distribution system in 2014 (Exh. DPU-Berkshire 2-1).[15] At the end of 2014, Berkshire had a total of 346 remaining unrepaired leaks, consisting of 61 Grade 2 leaks, and 285 Grade 3 leaks (Exh. DPU-Berkshire 2-4). Berkshire estimates that it would

14 Data provided in this column for Table 1 through Table 10 was pulled from the 2014 PHMSA Addendums to Form PHMSA F7100.1-1, as reported to the Department. LAUF due to leakage is reported in MMBTU; the Department converted MMBTU to Mcf by dividing the MMBTU by 1.026 per 40 C.F.R. Part 98, Subpart C, Table C-1.

15 Berkshire explains that the data provided in response to information request DPU-Berkshire 1-3 is the same as provided in Berkshire's 2014 SQ report except that Berkshire's 2014 SQ report also contains leak reported in 2015 (1/1/2015 – 2/28/15) because of an updated request to provide all data up to time of submission of the report (Exh. DPU-Berkshire 1-4).

cost $1,583,596, and take 8,304 person hours, to repair the 346 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exh. DPU-Berkshire 2-4).

Berkshire does not directly estimate LAUF or methane emissions associated with Grade 1, Grade 2, and Grade 3 leaks (Exh. DPU-Berkshire 1-6). Rather, Berkshire calculates and reports fugitive greenhouse gas emissions due to leakage in accordance with 310 C.M.R. § 7.71 (Exh. DPU-Berkshire 1-6, Att. (a)). As required by 310 C.M.R. § 7.71, Berkshire uses the 40 C.F.R. Part 98 Methodology to calculate fugitive methane emissions required for Massachusetts reporting (Exh. DPU-Berkshire 1-6, Att. (b)). Berkshire estimates a system-wide leak volume of 35,987.3 Mcf of LAUF and 724 MT of methane emissions in 2014 (Exhs. DPU-Berkshire 1-7; DPU-Berkshire 2-2 (rev.); Berkshire 2014 PHMSA Addendum). Table 2, below, provides a summary of Berkshire-specific gas leak and emissions data for calendar year 2014.

Table 2: Berkshire

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
75*	227	356	658	35,987.3	724	$1,583,596

* As stated above, no Grade 1 leaks existed on Berkshire's gas distribution system at the end of calendar year 2014.

3. Blackstone

Blackstone reports that it had no Grade 1 or Grade 2 leaks on its gas distribution in 2014. Blackstone reports that it had a total of 19 Grade 3 leaks on its gas distribution system in 2014, that all of the 19 Grade 3 leaks were repaired by the end of 2014, and that 95 percent of the leaks were due to a loose fitting or bad washer on a meter set (Exhs. DPU-Blackstone 1-3; DPU-Blackstone 1-8). Blackstone states that it costs approximately $200.00 and takes one hour of labor to repair each Grade 3 leak (Exh. DPU-Blackstone 1-8).

Blackstone estimates a system-wide LAUF volume of 60.1 Mcf and approximates that ten percent of the total LAUF is attributable to gas leaks in 2014 (Exhs. DPU-Blackstone 1-7 Att.; DPU-Blackstone 2-1; Blackstone 2014 PHMSA Addendum). Blackstone, however, does not directly estimate methane emissions associated with various grade leaks (Exh. DPU-Blackstone 1-7). Blackstone states that, pursuant to 310 C.M.R. § 7.71, it is not required to calculate and report fugitive greenhouse gas emissions due to leakage because its total unaccounted for emissions are below the applicable threshold of 238 short tons of methane (Exh. DPU-Blackstone 1-7). Table 3, below, provides a summary of Blackstone-specific gas leak and emissions data for calendar year 2014.

Table 3: Blackstone

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
0	0	19	19	60.1	N/A	N/A

4. Liberty Utilities

Liberty Utilities reports that it had a total of 86 Grade 1 leaks, 151 Grade 2 leaks, and 652 Grade 3 leaks on its gas distribution system in 2014 (Exhs. DPU-Liberty Utilities 1-3; DPU-Liberty Utilities 2-3). At the end of 2014, Liberty Utilities had a total of 424 remaining unrepaired leaks, consisting of 13 Grade 2 leaks, and 411 Grade 3 leaks (Exh. DPU-Liberty Utilities 2-3). Liberty Utilities estimates that it would cost $1,484,000, and take 10,176 person hours, to repair the 424 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exh. DPU-Liberty Utilities 2-3).

Liberty Utilities reports that it has undertaken measures to reduce LAUF on its system, and identifies a variety of factors that contribute to LAUF including: system leakage; metering variances; theft of service; purging during construction activities; and third-party damages (Exh. DPU-Liberty Utilities 1-6). Liberty Utilities reports that it uses a format provided by the US EPA to estimate the amount of LAUF attributable to system leakage. However, it is not able to provide a more reliable breakdown of the percentage of LAUF on its system by leak type because Liberty Utilities has no way of providing reasonable estimates attributable to the other causes (Exh. DPU-Liberty Utilities 1-6).

Liberty Utilities explains that it tracks gas volumes as: (1) those volumes received through purchases from its pipeline supplier; and (2) the liquefied natural gas ("LNG") boil off distributed and the vaporized LNG distributed into and out of the distribution system on a daily basis (Exh. DPU-Liberty Utilities 1-6). Liberty Utilities then summarizes those daily totals into monthly reports, one of which shows total volumes of gas purchased or otherwise delivered into the Company gas distribution system, plus the amount of gas produced (i.e., vaporized LNG), while the other report shows the total of gas volumes sold or transported to end use customers for the month, plus any gas used by the Company (Exh. DPU-Liberty Utilities 1-6). Twice annually, on June 30 and December 31, Liberty Utilities compares these monthly totals and calculates the total amount of LAUF by comparing the total annual gas delivered on the Company's system, or sendout, versus the calculation of the sum of gas sold directly, including transportation volumes and company-use (Exh. DPU-Liberty Utilities 1-6). Liberty Utilities states that the difference from these two totals derives the annual percentage LAUF (Exh. DPU-Liberty Utilities 1-6).

Similarly, Liberty Utilities reports that it has no means by which to isolate, discern, or specifically allocate, methane emissions to Grade 1, Grade 2, or Grade 3 leaks (Exh. DPU-Liberty Utilities 1-7). Liberty Utilities reports that, similar to Bay State, it calculated its estimated emissions using 40 C.F.R. Part 98 Methodology (Exhs. DPU-Liberty Utilities 1-7; DPU-Liberty Utilities 2-2; DPU-Bay State 1-7).[16]

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16 Liberty Utilities notes that the reported volume of fugitive emissions calculated using the 40 C.F.R. Part 98 Methodology leak factors is an estimate and does not represent actual methane emissions (Exh. DPU-Liberty Utilities 1-7). Moreover, Liberty

Liberty Utilities estimates a system-wide leak volume of 126,109.2 Mcf of LAUF,[17] and 1,297 MT of methane emissions in 2014 (see Exhs. DPU-Liberty Utilities 2-1 (rev.); DPU-Liberty Utilities 2-2). Table 4, below, provides a summary of Liberty Utilities-specific gas leak and emissions data for calendar year 2014.

Table 4: Liberty Utilities

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
86*	151	652	889	126,109.2	1,297	$1,484,000

*As stated above, no Grade 1 leaks existed on Liberty Utilities' gas distribution system at the end of calendar year 2014.

5. National Grid

National Grid reports that it had a total of 5,386 Grade 1 leaks, 4,386 Grade 2,[18] and 12,994 Grade 3 leaks on its gas distribution system in 2014 (Exh. DPU-National Grid 1-3).[19]

Utilities notes that methane emissions calculated using the 40 C.F.R. Part 98 Methodology is separate and distinct from LAUF and the two estimations do not correlate (Exh. DPU-Liberty Utilities 2-2).

17 Liberty does not identify LAUF due to leakage in its 2014 PHMSA Addendum, but has reported to the Department a total LAUF volume of 129,388 MMBTU or 126,109.2 Mcf.

18 National Grid's Grade 2 leak classification includes a higher priority subsection of leaks identified as Grade 2A leaks (Exhs. DPU-National Grid 1-3).

19 National Grid explains that the data provided in the National Grid's 2014 SQ report did not contain leaks eliminated without repair. The Company queried its leak management system for this data and included it along with the SQI data in the table shown in National Grid's response to information request DPU-National Grid 1-3 (Exh. DPU-National Grid 1-4).

At the end of 2014, National Grid had a total of 11,991 remaining unrepaired leaks, consisting of 86 Grade 1 leaks,[20] 470 Grade 2 leaks, and 11,435 Grade 3 (Exhs. DPU-National Grid 1-3; DPU-National Grid 2-3). National Grid estimates that it would cost $59,468,101, and take 389,418 person hours, to repair the 11,991 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exhs. DPU-National Grid 1-3; DPU-National Grid 2-3).

National Grid does not estimate the amount of LAUF by leak grade. National Grid also uses the 40 C.F.R. Part 98 Methodology to calculate estimated gas loss through system leakage. National Grid reports an estimated 967,517.5 Mcf of LAUF solely from pipe leakage in 2014 (Exh. DPU-National Grid 2-1 (rev.)).

Similarly, National Grid does not directly measure or estimate methane emissions associated with various leak grades (Exh. DPU-National Grid 1-7). Rather, National Grid calculates and reports fugitive greenhouse gas emissions due to leakage in accordance with 310 C.M.R. § 7.71 and uses the 40 C.F.R. Part 98 Methodology to calculate fugitive methane emissions required for Massachusetts reporting (Exh. DPU-National Grid 1-7). National Grid estimates 18,209 MT of methane emissions from system-wide leakage in 2014 (Exhs. DPU-National Grid 1-7; DPU-National Grid 2-2).

Table 5, below, provides a summary of National Grid-specific gas leak and emissions data for calendar year 2014.

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[20] National Grid has repaired all 86 Grade 1 leaks that were unrepaired at the time National Grid generated the SQ data at the end of calendar year 2014 (Exh. DPU-National Grid-1-3).

Table 5: National Grid

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
5,386*	4,386	12,994	22,766	967,517.5	18,209	$59,468,101

*As stated above, 86 Grade 1 leaks existed on National Grid's gas distribution system at the end of calendar year 2014. National Grid has now repaired all 86 Grade 1 leaks.

6. NSTAR

NSTAR reports that it had a total of 892 Grade 1 leaks, 1,230 Grade 2 leaks, and 3,915 Grade 3 leaks on its gas distribution system in 2014 (Exh. DPU-NSTAR 1-3).[21] At the end of 2014, NSTAR had a total of 3,978 remaining unrepaired leaks, consisting of 89 Grade 2 leaks, and 3,889 Grade 3 leaks (Exh. DPU-NSTAR 2-3). NSTAR estimates that it would cost $12,300,000, and take 111,384 person hours, to repair the 3,978 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exh. DPU-NSTAR 2-3).

[21] NSTAR notes that there is a difference between the data provided in response to information request DPU 1-3 and the data provided in NSTAR's 2014 SQ report. This is due to the timing that information on leak repairs and the detection of new leaks is received from the field and recorded in the leak database. There were additional leak repairs and leaks detected in 2014 that were reported from the field between the time the data was prepared for NSTAR's 2014 SQ report and the time the data was prepared for the Massachusetts Addendum (Sections 4.0 and 5.0) to the PHMSA Gas Distribution System Annual report in response to information request DPU-NSTAR 1-3 (Exh. DPU-NSTAR 1-4).

NSTAR does not directly estimate or report LAUF by leak grade (Exh. DPU-NSTAR 1-6). NSTAR asserts that there is no recognized industry standard to accurately determine LAUF from natural gas leaks (Exh. DPU-NSTAR 1-6). NSTAR explains that the amount of gas lost due to leaks cannot be accurately determined by leak or leak grade because the time at which the leak began is unknown (Exh. DPU-NSTAR 1-6). Therefore, NSTAR relies on its annual report to US EPA under 40 C.F.R. Part 98 to estimate LAUF due to system leaks (Exh. DPU-NSTAR 1-6). NSTAR calculates the total amount of natural gas emissions resulting from main and service leakage using the 40 C.F.R. Part 98 Methodology (Exh. DPU-NSTAR 1-6).

Similarly, NSTAR does not directly estimate the methane emissions associated with various grade leaks (Exh. DPU-NSTAR 1-7). NSTAR calculates and reports fugitive greenhouse gas emissions due to leakage in accordance with 310 C.M.R. § 7.71, and uses the 40 C.F.R. Part 98 Methodology to calculate fugitive methane emissions required for Massachusetts reporting.

NSTAR estimates a system-wide leak volume of 223,518.5 Mcf of LAUF and 4,085.5 MT of methane emissions in 2014 (Exhs. DPU-NSTAR 1-6; DPU-NSTAR 2-1; DPU-NSTAR 2-2). Table 6, below, provides a summary of NSTAR-specific gas leak and emissions data for calendar year 2014.

Table 6: NSTAR

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
892*	1,230	3,915	6,037	223,518.5	4,085.5	$12,300,000

*As stated above, no Grade 1 leaks existed on NSTAR's gas distribution system at the end of calendar year 2014.

7. Unitil

Unitil reports that it had a total of 329 Grade 1 leaks, 585 Grade 2 leaks, and 144 Grade 3 leaks on its distribution system in 2014 (Exh. DPU-Unitil 1-3). Unitil estimates that it would cost $487,655, and take a crew of three 150 working days (or approximately 3,600 person hours), to repair the 105 unrepaired Grade 3 leaks that existed on its distribution system at the end of 2014 (Exhs. DPU-Unitil 1-3; DPU-Unitil 1-8 (rev.)).

Unitil does not measure or track LAUF by sub-category, and, therefore, the LAUF associated specifically with gas leaks are an estimate by Unitil's leak management program. Unitil estimates 209.6 Mcf of the total LAUF attributed to gas leaks (Exh. DPU-Unitil 1-6; DPU-Unitil 2-1).

Unitil presumes that each Grade 1, Grade 2, and Grade 3 leak results in methane emissions. Unitil explains, however, that because there is no industry-accepted methodology to calculate the methane emissions for a specific grade leak given the unknowns, such as, the date and time that a leak commenced and the leak rate, the calculated methane emissions value represents the fugitive emissions for the entire natural gas distribution system

(Exh. DPU-Unitil 1-7). Unitil estimates a total amount of methane emissions due to leakage of 431.8 MT using the 40 C.F.R. Part 98 Methodology (DPU-Unitil 2-2).[22]

Table 7, below, provides Unitil-specific gas leak and emission data for calendar year 2014.

Table 7: Unitil

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
329*	585	144	1,058	209.6	431.8	$487,655

*As stated above, no Grade 1 leaks existed on Unitil's gas distribution system at the end of calendar year 2014.

8. Holyoke

Holyoke reports that it had a total of 55 Grade 1 leaks, 80 Grade 2 leaks, and 179 Grade 3 leaks on its gas distribution system in 2014 (Exh. DPU-Holyoke 1-3). At the end of 2014, Holyoke had a total of 161 remaining unrepaired leaks, consisting of 11 Grade 2 leaks, and 150 Grade 3 leaks (Exh. DPU-Holyoke 1-7). Holyoke estimates that it would cost $517,124, and take 5,715 person hours, to repair the 161 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (Exh. DPU-Holyoke 1-7).

Holyoke reports that it determined the LAUF and methane associated with each classification of leaks by calculating the fugitive emissions for mains and services using the

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22 Unitil adds that the accuracy of estimates of methane emissions cannot be verified and subsequent conclusions are limited to speculation (Exhs. DPU-Unitil 1-7; DPU-Unitil 2-2).

40 C.F.R. Part 98 Methodology (Exhs. DPU-Holyoke 1-5; DPU-Holyoke 1-6). Holyoke estimates a system-wide leak volume of 21,109.2 Mcf of LAUF and 340.9 MT of methane emissions in 2014 (Exhs. DPU-Holyoke 1-5; DPU-Holyoke 1-6). Table 8, below, provides a summary of Holyoke-specific gas leak and emissions data for calendar year 2014.

Table 8: Holyoke

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
55*	80	179	314	21,109.2	340.9	$517,124

* As stated above, no Grade 1 leaks existed on Holyoke's gas distribution system at the end of calendar year 2014.

9. Middleborough

Middleborough reports that it had a total of 21 Grade 1 leaks, 26 Grade 2 leaks, and 30 Grade 3 leaks in 2014 (Exh. DPU-Middleborough 1-3). Middleborough does not have time and repair costs to eliminate leaks on its distribution system at the end of 2014 because it repaired all 77 leaks in 2014 (Exh. DPU-Middleborough 1-7).

Middleborough is not able to determine the percentage of LAUF or methane emissions associated with each category of Grade 1, Grade 2, and Grade 3 leaks (Exhs. DPU-Middleborough 1-5; DPU-Middleborough 1-6).

Middleborough calculates fugitive greenhouse gas emissions due to leakage utilizing the 40 C.F.R. Part 98 Methodology. Middleborough estimates a system-wide leak volume of

292.4 Mcf of LAUF and 70.3 MT of methane emissions in 2014 (Exh. DPU-Middleborough 1-6).

Table 9, below, provides Middleborough-specific gas leak and emission data for calendar year 2014.

Table 9: Middleborough

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
21*	26	30	77	292.4	70.3	N/A

* As stated above, no Grade 1 leaks existed on Middleborough's gas distribution system at the end of calendar year 2014.

10. Wakefield

Wakefield reports that it had a total of 13 Grade 1 leaks, 133 Grade 2 leaks, and 89 Grade 3 leaks on its gas distribution system in 2014 (Exh. DPU-Wakefield 1-3). At the end of 2014, Wakefield had a total of 162 remaining unrepaired leaks, consisting of 90 Grade 2 leaks and 72 Grade 3 leaks (Exh. DPU-Wakefield 1-7). Wakefield explains that it implemented a plastic main upgrade program that eliminated 30 of the leaks, at a cost of $600,000 (Exh. DPU-Wakefield 2-2). Wakefield estimates that it would cost $459,175, and take a four person crew between eight to twelve hours per leak (or approximately 5,280 person hours), to repair the remaining 132 leaks (Exh. DPU-Wakefield 2-2).

Wakefield estimates approximately 25,138.2 Mcf of LAUF on its distribution system in 2014, and 4,766 Mcf of LAUF attributable to leaks on its distribution system in 2014 (Exh.

DPU-Wakefield 1-5; DPU-Wakefield 2-1 (rev.)). Wakefield does not estimate LAUF by leak grade.

Wakefield reports that it does not directly estimate methane emissions associated with Grade 1, Grade 2, and Grade 3 leaks because it has no means by which to isolate or discern estimates of methane emissions for 2014 limited specifically to Grade 1, Grade 2, and Grade 3 leaks (Exh. DPU-Wakefield 1-6). Moreover, Wakefield states that it is not required to report fugitive greenhouse gas emissions due to leakage in accordance with 310 C.M.R. § 7.71, because it produced less than 5,000 short tons of greenhouse gases in carbon dioxide equivalents (Exh. DPU-Wakefield 1-6).

Table 10, below, provides Wakefield-specific gas leak and emission data for calendar year 2014.

Table 10: Wakefield

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
13*	133	89	235	4,766	N/A	$1,059,175

*As stated above, no Grade 1 leaks existed on Wakefield's gas distribution system at the end of calendar year 2014.

11. Westfield

Westfield reports that it had a total of 19 Grade 1 leaks, 59 Grade 2 leaks, and 190 Grade 3 gas leaks in its gas distribution system in 2014 (see Exh. DPU-Westfield 1-3). At the end of 2014, Westfield had a total of 169 remaining unrepaired leaks, consisting of 2 Grade

2 leaks and 167 Grade 3 leaks (see Exhs. DPU-Westfield 1-3; DPU-Westfield 1-7). Westfield estimates that it would cost $525,200, and take 6,060 person hours, to repair the 169 remaining unrepaired leaks that existed on its distribution system at the end of 2014 (see Exhs. DPU-Westfield 1-3; DPU-Westfield 1-7).

Westfield estimates LAUF associated with Grade 1, Grade 2, and Grade 3 leaks at 25.2 Mcf for 2014 (see Exh. DPU-Westfield 1-5). Westfield estimates its leak rates based on Methane Emissions from the Natural Gas Industry, Vol. 9: Underground Pipelines, EPA Office of Research and Development, Washington, D.C. (June 1996). Westfield estimates that its total LAUF in 2014 is approximately 20,493.1 Mcf (Exh. DPU-Westfield 1-5).

Westfield estimates the amount of annual methane volume by multiplying the volume of LAUF natural gas by its methane content (0.934) (Exh. DPU-Westfield 1-6). Westfield then multiplied the methane volume by a soil oxidation factor to estimate annual methane emissions (Exh. DPU-Westfield 1-6). Westfield estimates that methane emissions associated with Grade 1, Grade 2, and Grade 3 leaks is 6.8 MT and the total methane emissions for Westfield's natural gas distribution system is approximately 9,178.5 MT (Exh. DPU-Westfield 1-6).

Table 11, below, provides Westfield-specific gas leak and emission data for calendar year 2014.

Table 11: Westfield

Grade 1 Leaks	Grade 2 Leaks	Grade 3 Leaks	Total Leaks	LAUF Leakage (Mcf)	Total Methane Emissions (MT)	2014 Repair Cost Estimate
19*	59	190	268	25.2[23]	9,178.5	$525,200

* As stated above, no Grade 1 leaks existed on Westfield's gas distribution system at the end of calendar year 2014.

C. Summary of Findings

Collectively, the gas distribution companies and municipal operators report a total of 9,855 Grade 1 leaks, 9,039 Grade 2 leaks, and 21,713 Grade 3 leaks (a cumulative total of 40,425 leaks) on the gas distribution system in calendar year 2014. At the end of 2014, there were 86 Grade 1 leaks, 1,230 Grade 2 leaks, and 19,459 Grade 3 leaks (a cumulative total of 20,773 leaks) remaining on the gas distribution system. The gas distribution companies and municipal operators estimate that it would cost $102,455,788 to repair the 20,773 remaining unrepaired leaks that existed on its distribution system at the end of 2014. As calculated and described above, the gas distribution companies and municipal operators estimate 1,658,102 Mcf of LAUF related to leakage, and 40,470.82 MT of methane emissions in 2014.

The data demonstrates that while the natural gas system incurred numerous Grade 1, Grade 2, and Grade 3 leaks during calendar year 2014, gas distribution companies and municipal gas operators also continuously engage in the ongoing repair of these leaks, with

[23] Westfield did not report LAUF due to leakage in its 2014 PHMSA Addendum. Westfield reported this measurement in response to the Department's information request DPU-Westfield 1-5.

specific prioritization being given to Grade 1 leaks, but with repair of significant numbers of outstanding Grade 2 leaks, as well as some Grade 3 leaks. The vast majority of unrepaired leaks as of the end of calendar year 2014 are those specifically classified as non-hazardous. Additionally, although National Grid reports that it had 86 Grade 1 leaks unrepaired at the time it generated the SQ data, it has now repaired all of those leaks (Exh. DPU-National Grid-1-3). All other gas distribution companies and municipal gas operators had repaired all Grade 1 leaks existing during calendar year 2014 by the end of calendar year 2014. Accordingly, any Grade 1 leaks identified in this report have now been repaired.

III. PIPELINE REPLACEMENT PROGRAMS

A. Introduction

As discussed above, a major reason for the number of natural gas leaks on the natural gas system is the presence of certain aging infrastructure. The Department has recognized that there may be public safety, service reliability, and environmental issues associated with the continued existence and aging of leak-prone facilities in gas companies' distribution systems. Bay State Gas Company, D.P.U. 09-30, at 133 (2009); New England Gas Company, D.P.U. 10-114, at 56 (2011). The Department has concluded that a sustained replacement of leak-prone facilities is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121 (2010); D.P.U. 10-114, at 56; D.P.U. 09-30, at 133-134. In the early 1990s, the Department promulgated regulations (220 C.M.R §§ 113.00 et seq.) prohibiting the installation of cast-iron pipe for the distribution of gas after April 12, 1991. Included in these regulations is the requirement that each gas distribution company develop and implement cast-iron replacement programs. There is also a mandatory provision requiring gas distribution companies to immediately replace cast-iron pipe that has been encroached upon.[24] In addition, there are currently two types of programs by which a gas distribution company may accelerate the repair or replacement of certain types of aging infrastructure: the TIRFs and the GSEPs. We discuss those programs below.

B. TIRFs

In order to accelerate replacement of leak-prone mains and associated facilities on gas company distribution systems, some companies requested, and the Department approved, implementation of a TIRF program. Specifically, the Department approved Bay State's proposal to implement a TIRF in 2009, National Grid's proposal to implement a TIRF program in 2010, and Liberty Utilities' proposal to implement a TIRF in 2010. D.P.U. 10-55, at 122; D.P.U. 09-30, at 134; D.P.U. 10-114, at 56, 76-77. The TIRF program allows National Grid, Liberty Utilities, and Bay State to recover the revenue requirement (including depreciation, return on investment, and property taxes) on investments made to replace leak-

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24 "Cast-iron pipe, eight inches or less in nominal diameter, that is exposed and undermined by a trench crossing the pipeline shall be replaced immediately: (a) When there is less than 24 inches of cover; or (b) When there is 24 inches or more of cover and the trench widths set forth in Table 1 are exceeded." 220 CMR 113.06(1). "Cast-iron pipe eight inches or less in nominal diameter, that is adjacent to parallel excavation shall be replaced immediately, provided that the excavation exceeds eight feet in length and a condition exists as set forth in 220 CMR 113.07(2), (3) or (4)." 220 C.M.R. §113.07(1).

prone mains, services, and other facilities through a reconciling mechanism outside of base rates. D.P.U. 10-55, at 137-138, 145; D.P.U. 10-114, at 35; Bay State Gas Company, D.P.U. 13-75, at 21 (2014). The Department has recognized that approval of a TIRF mechanism is likely to provide an incentive for more sustained and aggressive replacement of aging infrastructure, while lessening the impediment of current capital constraints. D.P.U. 10-55, at 122; D.P.U. 10-114, at 56.

While their service territories are unique and consist of different sizes with different infrastructure challenges, through the TIRFs, National Grid, Bay State, and Liberty Utilities replaced significant amounts of leak-prone infrastructure. Specifically, between 2010 and 2013, Boston Gas eliminated 335 miles of cast iron and non-cathodically protected steel mains, along with 8,000 services, and Colonial Gas eliminated 154 miles of cast iron and non-cathodically protected steel mains, along with 969 services. Boston Gas Company/Colonial Gas Company, D.P.U. 14-132, at 10 n.14 (2015). Between 2010 and 2013, Bay State eliminated 177 miles of cast iron and non-cathodically protected steel mains, along with 10,079 services. Bay State Gas Company d/b/a Columbia Gas of Massachusetts, D.P.U. 14-134, at 9 n.13 (2015). Finally, between 2010 and 2013, Liberty Utilities eliminated approximately 25 miles of non-cathodically protected steel or cast iron/wrought iron mains, along with replacement of 1,994 services. Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 14-133, Exh. LU-1, at 4 (2015).

C. GSEPs

1. Overview

Although several companies were operating under TIRFs to accelerate replacement of leak-prone infrastructure, the Act provided a new program by which gas distribution companies could replace aging infrastructure. Pursuant G.L. c. 164, § 145 each gas distribution company may annually submit a plan to accelerate the replacement of leak-prone infrastructure.[25] Any plan filed with the Department shall include, but not be limited to: (i) eligible infrastructure replacement of mains, services, meter sets and other ancillary facilities composed of non-cathodically protected steel, cast iron and wrought iron, prioritized to implement the federal gas distribution pipeline integrity management plan ("DIMP") annually submitted to the Department and consistent with the requirements of 49 C.F.R. §§ 192.1001 through 192.1015; (ii) an anticipated timeline for the completion of each project; (iii) the estimated cost of each project; (iv) rate change requests; (v) a description of customer costs and benefits under the plan; and (vi) any other information the Department considers necessary to evaluate the plan. G.L. c. 164, § 145(c). Additionally, the initial plan submitted to the Department must also include a timeline for removing all leak-prone infrastructure on an accelerated basis specifying an annual replacement pace and program end date with a target end date of either (i) not more than 20 years, or (ii) a reasonable target end

[25] For those gas distribution companies operating under a TIRF, the GSEP will effectively replace the TIRF for replacement of eligible infrastructure as of January 1, 2015.

date considering the allowable cost recovery cap established pursuant to subsection (f). G.L. c. 164, § 145(c).[26]

If a plan complies with Section 145, and the Department determines that it reasonably accelerates eligible infrastructure replacement and provides benefits to customers, the Department must preliminarily accept the plan either in whole or in part. G.L. c. 164, § 145(e). The gas distribution company may begin recovering the estimated plan revenue requirement beginning on May 1 of the year following submission of the plan. G.L. c. 164, § 145(e). Subsequently, on or before May 1 of each year, the gas distribution company must file final project documentation for construction completed the previous calendar year in order to demonstrate substantial compliance with the plan, and to demonstrate that the costs were reasonably and prudently incurred. G.L. c. 164, § 145145(f).

26 G.L. c. 164, § 145 further provides that annual changes in the revenue requirement eligible for recovery pursuant to the plan shall not exceed (i) 1.5 percent of the gas company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers, or (ii) an amount determined by the Department that is greater than 1.5 percent of the gas company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers. G.L. c. 164, § 145(f). The Department may modify a plan prior to approval at the request of a gas company, or make other modifications to a plan as a condition of approval. G.L. c. 164, § 145(d). The Department is required to consider the costs and benefits of the plan including, but not limited to, impacts on ratepayers, reductions of LAUF through a reduction in natural gas system leaks, and improvements to public safety. G.L. c. 164, § 145(d). The Department is also required to give priority to plans narrowly tailored to addressing leak prone infrastructure most immediately in need of replacement. G.L. c. 164, § 145(d).

2. 2015 GSEPs

a. Introduction

On October 31, 2014, seven gas distribution companies, Unitil, Berkshire, Liberty Utilities, National Grid,[27] Bay State, and NSTAR, each submitted to the Department their first annual GSEP to the Department.[28] As part of its proposed GSEP, each company, among other things, (1) submitted a plan to repair or replace eligible leak-prone infrastructure during calendar year 2015, (2) estimated a revenue requirement associated with that replacement, and (3) provided a timeline to repair or replace all leak-prone infrastructure in its gas distribution system. On April 30, 2015, the Department approved each company's proposed GSEP. The following provides a high-level summary of each approved GSEP, including the amount of leak-prone infrastructure on each company's system, the anticipated infrastructure that each company anticipates replacing during calendar year 2015, the revenue requirement associated with the 2015 GSEP, and the company's proposed timeline to repair or replace all leak-prone infrastructure. As demonstrated by the GSEPs, Massachusetts has set a course to eliminate leak-prone infrastructure on an accelerated basis.

b. Unitil 2015 GSEP

Unitil distributes natural gas to approximately 15,700 customers in six communities in Massachusetts. Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 14-130, at 9 (2015). D.P.U. 14-130, at 9. Unitil owns and operates approximately 275 miles of

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27 Both Boston Gas Company and Colonial Gas Company submitted a GSEP.

28 Blackstone did not submit a GSEP because its gas distribution system contains no leak-prone infrastructure.

distribution mains and 10,930 services. Unitil states that approximately 3.48 percent (9.56 miles) of its distribution system mains are composed of unprotected bare steel and wrought iron, and approximately 23.86 percent of its distribution system (65.54 miles) is composed of cast iron, which means that approximately 27.34 percent of the distribution system mains (75.1 miles) are composed of leak-prone materials. D.P.U. 14-130, at 9. Unitil states that these facilities account for approximately 86 percent of the leaks occurring on the Unitil's mains in a year D.P.U. 14-130, at 9.

Historically, Unitil has replaced a minimum of two miles of leak-prone pipe per year. D.P.U. 14-130, at 9. Under the approved GSEP, Unitil anticipates replacing 3.69 miles of leak-prone mains and 381 associated services in 2015. D.P.U. 14-130, at 9. Unitil estimates that it will require a 20-year period to replace all eligible leak-prone infrastructure, including mains, services, meter sets, and other ancillary facilities, with an anticipated replacement rate of 3.75 miles per year. D.P.U. 14-130, at 9. Unitil's revenue requirement associated with recovery of 2015 GSEP costs is $284,456. D.P.U. 14-130, at 10.

c. Berkshire 2015 GSEP

Berkshire distributes natural gas to 40,000 customers in Berkshire county and portions of Hampshire and Franklin counties. Berkshire Gas Company, D.P.U. 14-131, at 9 (2015). Berkshire operates a network of approximately 759 miles of natural gas mains and over 31,000 active services. D.P.U. 14-131, at 9. Berkshire states that about 18 percent of its system mileage consists of leak-prone mains and services comprising cast iron, bare steel, and non-cathodically protected coated steel pipe. D.P.U. 14-131, at 9. Berkshire further states that these cast iron and unprotected steel facilities account for approximately 81 percent of all leaks that occurred on its system in 2013. D.P.U. 14-131, at 9.

Historically, Berkshire has replaced these leak-prone mains at a rate of 3.4 to 4.4 linear miles per year. D.P.U. 14-131, at 9. Berkshire anticipates replacing 109 miles of leak-prone cast iron and bare steel infrastructure on an accelerated basis through its GSEP over the next 20 years, beginning January 1, 2015, and ending December 31, 2034. D.P.U. 14-131, at 9. Berkshire states that it intends to retire approximately 5.5 miles of main each year of the GSEP, depending on a variety of factors and opportunities. D.P.U. 14-131, at 9. (Exh. Berkshire-DMG-1, at 6; Tr. 1, at 26). Berkshire's revenue requirement associated with recovery of 2015 GSEP costs is $226,850. D.P.U. 14-131, at 10.

d. National Grid 2015 GSEP

In Massachusetts, National Grid distributes natural gas to approximately 876,000 customers in 116 cities and towns. D.P.U. 14-132, at 9. As of December 31, 2013, National Grid owns and operates 11,021 miles of distribution mains and over 720,000 services. D.P.U. 14-132, at 9. For Boston Gas, National Grid states that approximately 17 percent of the distribution system mains are composed of non-cathodically protected steel and 29 percent of the distribution system mains are composed of cast iron and wrought iron; thus, approximately 46 percent of the distribution system mains are composed of leak-prone pipe. D.P.U. 14-132, at 9. For Colonial Gas, National Grid states that approximately five percent of the distribution system mains are composed of non-cathodically protected steel and three percent of the distribution system mains are composed of cast iron and wrought iron; thus, approximately eight percent of the distribution system mains are composed of leak-prone pipe. D.P.U. 14-132, at 9.

Between 2010 and 2013, Boston Gas replaced an average of 84 miles of leak-prone pipe per year, and Colonial Gas replaced an average of 39 miles of leak-prone pipe per year D.P.U. 14-132, at 9-10. Under its approved GSEP, Boston Gas anticipates replacing 113 miles of leak-prone mains in 2015, increasing to 150 miles per year by 2021, and again increasing to 170 miles per year by 2023. D.P.U. 14-132, at 10. Under its approved GSEP, Colonial Gas anticipates replacing 43 miles of leak-prone mains in 2015, and decreasing to less than 30 miles in 2019. D.P.U. 14-132, at 10. For Boston Gas, National Grid anticipates it will take 20 years to replace all eligible leak-prone facilities. D.P.U. 14-132, at 10. For Colonial Gas, National Grid anticipates it will take eight years to replace all eligible leak-prone facilities. D.P.U. 14-132, at 10.

Boston Gas's revenue requirement associated with recovery of 2015 GSEP costs is $8,292,527; Colonial Gas revenue requirement associated with recovery of 2015 GSEP costs is $1,417,131. D.P.U. 14-132, at 85 n.40.

e. Liberty Utilities

Liberty Utilities distributes natural gas to approximately 54,000 customers in the Fall River, North Attleboro, Plainville, Swansea, Somerset, and Westport communities of Massachusetts. Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 14-133, at 9 (2015). As of December 31, 2013, approximately 16.48 percent of Liberty Utilities' distribution system is composed of non-cathodically protected steel mains and approximately

20.33 percent is composed of smaller diameter cast iron and wrought iron mains, which means that more than one-third of the distribution mains on the system are composed of relatively higher risk materials (36.81 percent). D.P.U. 14-133, at 9. With large diameter cast iron mains included, approximately 37.57 percent of the distribution system qualifies as "leak prone" by industry standards. 13,711, or approximately 39 percent, of the services existing on the Liberty Utilities distribution system are composed of non-cathodically protected steel. D.P.U. 14-133, at 9.

Pursuant to the GSEP, Liberty Utilities anticipates that it will repair or replace nine miles of leak-prone pipe in 2015 and twelve miles per year by year five of the GSEP. D.P.U. 14-133, at 29. Liberty Utilities plans to implement a 20-year GSEP to replace a total of 230 miles of leak-prone main and 13,711 unprotected steel services. D.P.U. 14-133, at 39. Liberty Utilities' revenue requirement associated with recovery of 2015 GSEP costs is $588,575. D.P.U. 14-133, at 92.

f. Bay State

Bay State distributes natural gas to approximately 295,000 customers in 61 communities in three operating areas in Massachusetts: the Brockton operating area, the Springfield operating area, and the Lawrence operating area. Bay State Gas Company d/b/a Columbia Gas of Massachusetts, D.P.U. 14-134, at 9 (2015). As of December 31, 2013, Bay State owns and operates 4,857 miles of distribution mains and over 260,097 services. D.P.U. 14-134, at 9. Bay State states that approximately 6.1 percent of Bay State's distribution system mains are composed of non-cathodically protected steel and 14.5 percent is composed of smaller diameter cast iron and wrought iron, which means that more than one-fifth of the system is composed of relatively higher risk materials (20.6 percent). D.P.U. 14-134, at 9. Bay State states that with large diameter cast iron mains included, approximately 20.9 percent of the distribution system qualifies as leak prone per industry standards. D.P.U. 14-134, at 9. Bay State asserts that almost 19 percent of the services existing on the its distribution system are composed of non-cathodically protected steel. D.P.U. 14-134, at 9.

Historically, Bay State has replaced an average of 35 miles of leak-prone pipe per year. D.P.U. 14-134, at 9. Under its approved GSEP, Bay State anticipates replacing 44 miles of leak-prone mains and 4,900 priority services in 2015. D.P.U. 14-134, at 9-10. Bay State states that under the GSEP, it anticipates replacing over 1,000 miles of leak-prone pipe and 48,000 leak-prone services within the Company's three service areas. D.P.U. 14-134, at 10. Bay State estimates that it will replace all eligible leak-prone infrastructure, including mains, services, meter sets and other ancillary facilities in a 20-year period, with the first five years comprising the ramp-up period, the next five years comprising a level run-rate for replacement, and the remaining ten years comprising a ramp-down period for replacing the remaining leak-prone infrastructure. D.P.U. 14-134, at 10.[29] During the ramp-up period, the Company intends to increase the rate of leak-prone main replacement by five miles each year.

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[29] Bay State states that it requires a ramp-up period in order to develop, train, and qualify additional internal and contractor personnel to construct and install pipelines, as well as field personnel to inspect replacement work. D.P.U. 14-134, at 10. Additionally, the Company will need to retain additional office personnel to manage the intake and closing of the work orders associated with the accelerated replacement of leak-prone infrastructure. D.P.U. 14-134, at 10 n.14.

D.P.U. 14-134, at 10. Bay State's revenue requirement associated with recovery of 2015 GSEP costs is $2,625,905. D.P.U. 14-134, at 10.

g. NSTAR

NSTAR distributes natural gas to approximately 300,000 customers in 51 communities in central and eastern Massachusetts covering 1,067 square miles with an aggregate population of 1.2 million people. NSTAR Gas Company, D.P.U. 14-135, at 9 (2015). As of December 31, 2013, the Company owns and operates 3,213 miles of distribution mains and over 195,000 services. D.P.U. 14-135, at 9. NSTAR states that approximately 23 percent (745 miles) of the Company's distribution system mains are composed of non-cathodically protected steel and wrought iron, and approximately 12 percent of its distribution system (388 miles) is composed of cast iron, which means that approximately 35 percent of the distribution system mains (1,133 miles) are composed of leak-prone materials. D.P.U. 14-135, at 9. NSTAR states that these facilities account for approximately 91 percent of the leaks occurring on the Company's mains in a year. D.P.U. 14-135, at 9.

Historically, NSTAR has replaced an average of 25 miles of leak-prone pipe per year. D.P.U. 14-135, at 10.[30] Under the approved GSEP, NSTAR anticipates replacing 30 miles of leak-prone mains and 2,480 associated services in 2015. D.P.U. 14-135, at 10. NSTAR estimates that it will require a 25-year period to replace all eligible leak-prone infrastructure,

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30 Between 2001 and 2013, NSTAR states that it eliminated 260 miles of cast iron and non-cathodically protected steel mains, along with 19,545 services, and has reduced the profile of leak-prone mains from 49 percent of the system to the current 35 percent, and leak-prone services from 34 percent to the current 20 percent. D.P.U. 14-135, at 10 n.15.

including mains, services, meter sets and other ancillary facilities, with an anticipated replacement rate of 50 miles per year following an initial five-year ramp-up period. D.P.U. 14-135, at 10.[31] During the ramp-up period, the Company intends to increase the rate of leak-prone main replacement by five miles each year (Exh. NSTAR-RJB-2, at 10).

In its GSEP, NSTAR proposed to defer for one year the collection of its calendar year 2015 GSEP revenue requirement, estimated at $2,906,000. D.P.U. 14-135, at 1, 10-11. Among other things, the AG Settlement required that the base distribution rates in effect on January 1, 2012 for the operating utility companies be frozen for 44 months, and that in no event would new rates go into effect before January 1, 2016. D.P.U. 14-135, at 137, citing D.P.U. 10-170-B, AG Settlement, Art. II(3). The Department determined that the rate freeze approved in D.P.U. 10-170-B, pursuant to the AG Settlement, prohibited the Company from recovering costs incurred during the rate freeze period, unless those costs were incurred as a result of a statutory mandate enacted following the AG Settlement. D.P.U. 14-135, at 142. The Department determined that the rate freeze prohibited NSTAR from recovering costs incurred during the rate freeze period associated with a voluntary program such as the GSEP. D.P.U. 14-135, at 142-143. Accordingly, while the Department approved NSTAR's GSEP, we denied NSTAR the associated revenue requirement for 2015. D.P.U. 14-135, at 143-144.

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31 NSTAR states that it requires a ramp-up period in order to develop, train, and qualify additional internal and contractor personnel to construct and install pipelines, as well as field personnel to inspect replacement work. D.P.U. 14-135, at 10. Additionally, the Company will need to retain additional office personnel to manage the intake and closing of the work orders associated with the accelerated replacement of leak-prone infrastructure. D.P.U. 14-135, at 10 n.16.

IV. ICF REPORT

Beyond the TIRF and GSEP proceedings, the Department commissioned ICF to conduct a study regarding both LAUF and methane emissions from the gas distribution system in Massachusetts. Among other things, and pertinent to this report, the study concludes that LAUF is not an appropriate surrogate for methane emissions, and that the Department should not use LAUF, as currently defined in Massachusetts, to draw conclusions on the efficiency of the natural gas distribution systems (ICF International, LAUF Report, December 23, 2014, §4.1.1). The ICF study distinguishes three concepts: (1) LAUF; (2) lost gas; and (3) methane emissions (ICF International, LAUF Report, December 23, 2014, at i):

> LAUF refers to the difference between the total amount of gas that a gas distribution company purchases and the amount it delivers to customers. It includes all components of loss, such as leakage, venting, theft, and gas used by the distribution company itself, adjusted by some companies for meter errors, billing cycle issues, and other considerations. LAUF is essentially an accounting concept.
>
> Lost gas refers to all natural gas that escapes from the distribution system. For example, all vented gas is lost to the distribution system, but stolen gas does not escape from the distribution system and does not count as "lost." Lost gas is a subset of LAUF.
>
> Methane emissions refers to the methane portion of natural gas that actually reaches the atmosphere. It is important to understand that not all LAUF or even lost gas results in methane emissions. For example, some leaking gas never reaches the atmosphere, and thus does not end up as "methane emissions" (although it is "lost"). Methane emissions are a subset of lost gas (and therefore also of LAUF).

The ICF study found that the current definitions do not provide a uniform set of LAUF components to be included in the LAUF calculation, and do not define methods to quantify each component (ICF International, LAUF Report, December 23, 2014, §4.1.1). Moreover, the ICF study found that, under the current definitions, gas distribution companies may account for none, some, or all components, and may choose how they calculate the component values (id.). Therefore, values of LAUF cannot be compared among gas distribution companies because of the inconsistency in how they are calculated (id.). The ICF study recommends that a standardized method for the calculation and reporting of LAUF be developed. The Department is currently reviewing the ICF recommendations.

V. UNIFORM GAS LEAK CLASSIFICATION

As discussed above, G.L. c. 164, § 144, provides for a uniform gas leak classification based upon the hazard presented by a gas leak. Depending on the hazard presented, a leak will be classified either as a Grade 1, Grade 2, or Grade 3 leak. Based upon that classification, and as discussed above, G.L. c. 164, § 144, provides a timeline for replacement of the leak and, for Grade 2 and Grade 3 leaks, which are deemed non-hazardous, further outlines ongoing monitoring and reevaluation requirements until the leak is fixed.

Additionally, G.L. c. 164, § 144(d) requires prioritization of repairs of gas leaks detected within a school zone, and G.L. c. 164, § 144(e) requires the gas distribution companies to, beginning in 2014, report in their annual service quality ("SQ") reports the location of each Grade 1, Grade 2, and Grade 3 leaks existing as of the date of the report, the date each leak was classified, and the dates of repairs performed on each Grade 1, Grade 2, and Grade 3 leak.

To date, gas operators have formed a working group to develop uniform procedures/guidelines in response to the requirements of G.L. c. 164, § 144. The

Department's Pipeline Division continues to work with the gas operators to finalize those guidelines. Once finalized, the Department will initiate a formal rulemaking wherein we intend to codify: (1) the uniform natural gas leak classifications for Grade 1, Grade 2, and Grade 3 leaks; (2) the requirement to prioritize pipeline repairs for gas leaks detected within a school zone; and (3) the associated SQ reporting requirement. The Department may also consider directives to gas distribution companies regarding the format in which companies should report SQ gas leak data.

VI. CONCLUSION

Pursuant to Section 9, the Department has gathered data from gas distribution companies and municipal gas operators regarding the prevalence of natural gas leaks on the natural gas system. As indicated above, that data represents the total, cumulative leaks by grade during calendar year 2014, as well as system-wide LAUF and methane emissions. The data demonstrates that while the natural gas system incurred numerous Grade 1, Grade 2, and Grade 3 leaks during calendar year 2014, gas distribution companies and municipal gas operators also continuously engage in the ongoing repair of these leaks, with specific prioritization being given to Grade 1 leaks, which are defined as hazardous leaks, but with repair of significant numbers of outstanding Grade 2 leaks, as well as some Grade 3 leaks, which are non-hazardous leaks. With the exception of one gas distribution company, all Grade 1 leaks that existed on the gas distribution system during calendar year 2014 had been repaired by the end of 2014. Additionally, National Grid has repaired the 86 Grade 1 leaks that existed on its gas distribution system at the end of 2014.

As discussed above, a major reason for the occurrence of natural gas leaks in the Massachusetts is the presence of certain types of older infrastructure, including non-cathodically protected steel, cast-iron pipe, and wrought-iron pipe. The Department has historically recognized public safety and environmental issues posed by natural gas leaks, and believes that those are being addressed in several ways, including through implementation of a cast-iron replacement program, approval of TIRF programs for certain gas distribution companies, and approval of GSEPs submitted by seven of the eight gas distribution companies to accelerate the replacement of aging infrastructure. The Department will continue to monitor progress of gas distribution companies in replacing aging infrastructure through review of the gas distribution companies' annual GSEP filings to repair or replacing aging or leak-prone infrastructure the following calendar year, and through review of the companies' final project documentation filings that will detail the repair or replacement work performed in the previous calendar year. Further, the Department commissioned the ICF study to consider issues of natural gas leaks, LAUF, and methane emissions, and the Department is presently reviewing the ICF recommendations for potential action. Finally, although gas distribution companies are classifying gas leaks pursuant to the uniform gas leak classification requirements prescribed in G.L. c. 164, § 144, the Department will be initiating a formal rulemaking to codify those provisions as well as associated SQ reporting requirements.

The Department thanks the Joint Committee on Telecommunications, Utilities and Energy and the Joint Committee on Public Safety and Homeland Security for the opportunity to present this report addressing gas leaks in the natural gas distribution system. As discussed above, the Department will continue to monitor and work with the gas distribution companies to ensure that gas leaks are repaired in a timely and cost-efficient manner in order to ensure continued public safety in the Commonwealth of Massachusetts.

Respectfully Submitted,

Angela M. O'Connor

Angela M. O'Connor, Chairman

Jolette A. Westbrook, Commissioner

Robert E. Hayden

Robert E. Hayden, Commissioner